Premium Value.
Defined Growth.
Independent.
Canadian Natural.

2018 ANNUAL REPORT

2018 Performance Highlights

Canadian Natural's diverse and balanced asset base, continued focus on effective and efficient operations along with capital flexibility delivered a strong year for the Company, creating significant value for its shareholders.

		2018		2017		2016
FINANCIAL ($ millions, except per common share amounts)						
Product sales [1]	**$**	**22,282**	$	18,360	$	12,002
Net earnings (loss)	**$**	**2,591**	$	2,397	$	(204)
Per common share – basic	**$**	**2.13**	$	2.04	$	(0.19)
– diluted	**$**	**2.12**	$	2.03	$	(0.19)
Adjusted net earnings (loss) from operations [2]	**$**	**3,263**	$	1,403	$	(669)
Per common share – basic	**$**	**2.68**	$	1.19	$	(0.61)
– diluted	**$**	**2.67**	$	1.19	$	(0.61)
Cash flows from operating activities	**$**	**10,121**	$	7,262	$	3,452
Adjusted funds flow [3]	**$**	**9,088**	$	7,347	$	4,293
Per common share – basic	**$**	**7.46**	$	6.25	$	3.90
– diluted	**$**	**7.43**	$	6.21	$	3.89
Cash flows used in investing activities	**$**	**4,814**	$	13,102	$	3,811
Net capital expenditures [4]	**$**	**4,731**	$	17,129	$	3,794
Long-term debt [5]	**$**	**20,623**	$	22,458	$	16,805
Shareholders' equity	**$**	**31,974**	$	31,653	$	26,267
OPERATING						
Daily production, before royalties						
Crude oil and NGLs (Mbbl/d)						
North America – excluding Oil Sands Mining and Upgrading		**351**		360		351
North America – Oil Sands Mining and Upgrading		**426**		282		123
North Sea		**24**		23		24
Offshore Africa		**20**		20		26
		821		685		524
Natural gas (MMcf/d)						
North America		**1,490**		1,601		1,622
North Sea		**32**		39		38
Offshore Africa		**26**		22		31
		1,548		1,662		1,691
Barrels of oil equivalent (MBOE/d) [6]		**1,079**		962		806

(1) 2017 and 2016 comparative figures have been restated in accordance with adoption of IFRS 15 on January 1, 2018. See note 2 of the Company's consolidated financial statements.
(2) Adjusted net earnings (loss) from operations is a non-GAAP measure that the Company utilizes to evaluate its performance, as it demonstrates the Company's ability to generate after-tax operating earnings from its core business areas. The derivation of this measure is discussed in the Management's Discussion and Analysis ("MD&A").
(3) Adjusted funds flow (previously referred to as funds flow from operations) is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital reinvestment and to repay debt. The derivation of this measure is discussed in the MD&A.
(4) Net capital expenditures is a non-GAAP measure that the Company considers key as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. The derivation to this measure is discussed in the MD&A.
(5) Includes the current portion of long-term debt.
(6) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.

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	2018	2017	2016
Drilling activity (net wells) (1)			
North America	**504**	521	188
North Sea	**4**	2	1
Offshore Africa	**2**	–	1
	510	523	190
Core unproved property (thousands of net acres)			
North America	**19,736**	18,795	17,579
North Sea	**61**	72	78
Offshore Africa	**993**	2,194	2,194
	20,790	21,061	19,851
Company Gross proved plus probable reserves (2)			
Crude oil and NGLs (MMbbl)			
North America	**11,453**	9,958	7,281
North Sea	**186**	180	253
Offshore Africa	**121**	125	133
	11,760	10,263	7,667
Natural gas (Bcf)			
North America	**9,633**	9,520	8,911
North Sea	**38**	32	85
Offshore Africa	**63**	67	80
	9,734	9,619	9,076
Barrels of oil equivalent (MMBOE)	**13,382**	11,866	9,179

(1) Excludes net stratigraphic test and service wells.
(2) Year-end proved plus probable reserves were prepared using forecast prices and costs.

14%

ANNUAL BOE PRODUCTION PER SHARE GROWTH

52%

OF BOE PRODUCTION IS SCO, LIGHT CRUDE OIL & NGLS

Letter to our Shareholders

In 2018, Canadian Natural demonstrated the strength of our diverse, balanced and vast asset base, and our ability to create value for our shareholders throughout the commodity price cycle. Canadian Natural's continued focus on effective and efficient operations, ability to exercise capital flexibility within our four pillars of capital allocation and our combination of long life low decline and low capital exposure assets resulted in annual adjusted funds flow of over $9.0 billion. 2018 was a strong year operationally as the Company was able to react quickly and strategically to changing market conditions, resulting in record annual production of approximately 1,079,000 BOE/d, delivering 12% production growth and 14% production per share growth over 2017 levels. Returns to shareholders were significant in 2018 totaling $2.8 billion, which included an increase in the Company's dividend for the 18th consecutive year by 22% from 2017 levels and over $1.2 billion in share purchases. Throughout 2018, Canadian Natural demonstrated its commitment to balance sheet strength through a reduction in absolute long-term debt by approximately $1.8 billion, resulting in an upgrade to our already investment grade credit ratings.

The Company's industry leading Oil Sands Mining and Upgrading area continued to deliver strong results in 2018, driving high reliability of operations and capturing synergies which significantly lowered the cost structure. As a result, the Company's combined Oil Sands Mining and Upgrading assets achieved record low annual cash production costs of $21.75/bbl (US$16.78/bbl) of synthetic crude oil ("SCO"). The year 2018 represented the first full year of production following the successful completion of the Horizon Phase 3 expansion in late 2017, which increased productive capacity to 250,000 bbl/d of SCO at the Horizon site. At the Company's 70% owned and operated Athabasca Oil Sands Project ("AOSP"), teams achieved an impressive milestone of a cumulative lifetime production to date of 1 billion barrels on July 18, 2018, supported by net annual production of approximately 199,000 bbl/d of SCO in 2018. Additionally, due to the opportunistic acquisition of the Joslyn lease directly south of Horizon, Canadian Natural targets to optimize its mine plan going forward at Horizon, targeting future savings of approximately $500 million.

The Company's thermal in situ teams worked together effectively to enhance our growth projects in 2018. At Kirby North, construction and drilling activities continued in 2018 and as a result of top tier execution and strong productivity from our teams, the project is on budget and the timeline has been accelerated by two quarters, with first steam targeted in late Q2/19. Additionally, work on the Company's Primrose pad additions are also on budget and ahead of schedule, with the first twelve months of production targeted to be 26,000 bbl/d. The Company continues to advance technology to enhance performance and improve steam-to-oil ratios with the installation of vacuum insulated tubing ("VIT") on step-out wells at Kirby South. The wells with VIT installed have improved operations as expected, lowering steam use by approximately 30%, which if applied to additional wells will add value for shareholders.

In the Company's conventional North American Exploration and Production assets, average crude oil and NGL production in 2018 was just over 243,000 bbl/d and natural gas production was approximately 1,550 MMcf/d. Crude oil and NGL production represented an improvement of approximately 4,000 bbl/d over 2017 levels, impressive results given strategic voluntary production curtailments throughout the year. With a focus on execution excellence, drilling teams worked together to complete the 2018 Wembley drilling program, achieving enhanced drilling performance with drilling days reduced by 30% and cost reductions of 17%. New multilateral technology has been successfully deployed in the Company's Smith primary heavy crude oil play with production continuing to exceed sanctioned rates. As a result, the Company is looking to leverage this technology further within the Company's vast heavy crude oil land base. Within the Company's natural gas assets, at Septimus, a natural gas reinjection pilot is being advanced in 2019. If successful, natural gas reinjection technology has the potential to add

$2.8 BILLION

RETURNED TO SHAREHOLDERS

$1.8 BILLION

LONG-TERM DEBT REDUCTION

N. MURRAY EDWARDS
Executive Chairman

STEVE W. LAUT
Executive Vice-Chairman

TIM S. MCKAY
President

COREY B. BIEBER
Chief Financial Officer & Senior Vice-President, Finance

significant value by leveraging the Company's strategically owned and operated facilities and unlocking liquids rich development without producing incremental natural gas into a constrained takeaway environment.

International production was strong in 2018, averaging approximately 43,600 bbl/d. International teams hit a key production milestone at Baobab (Offshore Africa) in November 2018 with 100 million barrels of light crude oil produced from the field since first production in 2005. The Company drilled 1.7 net producer wells in Baobab in the second half of 2018 and performance from the wells has exceeded production expectations. As a result Canadian Natural targets to drill one additional producer well at Baobab in 2019. The Company also targets to drill an appraisal well at Kossipo which, if successful, could lead to development drilling and a pipeline tied-back to the Baobab Floating Production Storage and Offloading vessel, adding future value with significant potential production capability. Additionally, in the North Sea 3.9 net producer wells were drilled on time and on budget during 2018, with strong light crude oil production results.

Effective and efficient operations and capital discipline will continue to be a focus for the Company in 2019. Our 2019 base capital budget is disciplined and is targeted to be approximately $3.7 billion driving corporate production volumes of approximately 1,075,000 BOE/d at the midpoint of the Company's annual corporate guidance. Additionally, if commodity prices remain stable and as visibility to market access improves, the Company has identified opportunities to invest incremental capital in the latter half of 2019 of up to approximately $680 million, which would add future value beyond 2019 within the Company's Oil Sands Mining and Upgrading, thermal in situ and conventional areas.

Canadian Natural is a unique E&P company that is delivering free cash flow, strong and growing returns to shareholders and increasing returns on capital combined with the vast inventory of assets and discipline to allocate capital to maximize shareholder value and drive per share value growth. Canadian Natural has a strong track record of optimizing capital allocation to our four pillars; balance sheet strength, returns to shareholders, economic resource development and opportunistic acquisitions, to maximize shareholder value and 2019 will be no different. Canadian Natural has the strength and ability to continue to deliver top tier effective and efficient operations, a robust balance sheet, low maintenance capital and low breakeven prices. Canadian Natural's biggest strength, our people, will continue to make a significant difference in our performance, driven by continuous improvement and our top tier safety performance, while minimizing the Company's environmental footprint through leveraging technology and innovation.

Canadian Natural looks forward to building on the many successes achieved in 2018.

N. MURRAY EDWARDS
Executive Chairman

STEVE W. LAUT
Executive Vice-Chairman

TIM S. MCKAY
President

COREY B. BIEBER
Chief Financial Officer
& Senior Vice-President,
Finance

Our World-Class Team

Our proven strategy and disciplined business approach are supported by our dedicated teams and experienced management team.

G. Aalders, E. Aasen, A. Abadier, L. Abadier, Z. Abbas, T. Abbasi, D. Abbott, J. Abbott, M. Abbott, I. Abdi, A. Abdolmaleki, M. Abdulrhman, A. Abeda, W. Abeda, D. Abel, R. Abel, T. Abercrombie, G. Abou Mechrek, R. Abrams, A. Abramyan, J. Abramyk, J. Abreu, N. Abro, C. Acharya, D. Acheson, R. Ackerman, J. Acosta, J. Acteson-Grill, N. Adair, T. Adair, S. Adam, I. Adam, B. Adams, D. Adams, K. Adams, M. Adams, D. Adamson, P. Adamson, R. Adamson, C. Adan, D. Addinall, A. Adebayo, Y. Adebayo, K. Adejare, S. Adel, M. Aden, A. Adesanya, O. Adigun, M. Aditiakusuma, B. Adkins, R. Adzabe Ella, J. Agate, F. Agbadou, A. Agnihotri, K. Agombar, I. Agu, U. Agu, A. Agustin, E. Agyemang, C. Agyemang-Badu, J. Ahmad, M. Ahmad, N. Ahmad, O. Ahmad, R. Ahmad, S. Ahmad, A. Ahmadi, M. Ahmadi, F. Ahmadloo, A. Ahmari, A. Ahmed, R. Ahmed, S. Ahmed, M. Ahoonmanesh, T. Aickelin, R. Aidoo, R. Aikens, G. Ailsby, K. Airth, J. Airton, C. Aitchison, K. Aitchison, S. Aitken, T. Ajayi, J. Ajedegba, L. Ajijolaiya, S. Akhtar, R. Akinde, I. Akinnola, D. Akins, A. Akinsanya, J. Akolkar, N. Akolkar, S. Akolkar, I. Alallam, C. Alarcon, J. Albert, J. Alcala, E. Alconcel, M. Al-Dhabbi, J. Aleman, A. Alexander, B. Alexander, D. Alexander, J. Alexander, P. Alexander, S. Alexander, B. Alfred, A. Ali, G. Ali, S. Ali, R. Aliazas, H. Aljanabi, C. Allan, J. Allan, E. Allan, E. Allard, J. Allard, L. Allegretto, H. Allen, J. Allen, T. Allen, W. Allerton, D. Allibone, S. Allport, J. Allsop, B. Almen, M. Almestar Bustamante, S. Almstrong, Y. Alnumi, Y. Al-Saeedi, A. Al-Saleem, R. Al-Samarrai, S. Al-Siani, A. Alstad, C. Altrogge, J. Alvarez, J. Alvarez Luzon, B. Alyman, D. Amalaman, J. Aman, M. Amar, T. Amara, A. Amay, A. Amer, B. Amer, K. Amer, J. Amero, D. Ames, E. Amos, W. Amy, D. Anctil, J. Andel, D. Anders, D. Andersen, T. Andersen, A. Anderson, B. Anderson, C. Anderson, D. Anderson, G. Anderson, J. Anderson, K. Anderson, L. Anderson, M. Anderson, N. Anderson, P. Anderson, R. Anderson, W. Anderson, D. Andreoli, C. Andres, J. Andres, B. Andrews, D. Andrews, K. Andrews, T. Andrews, C. Angeles, P. Angell, L. Angen, K. Angerman, N. Ango Mfene, M. Anis, S. Annis, L. Anongba, M. Ansah-Sam, A. Ansell, C. Ansong-Danquah, D. Ansorger, R. Anstett, G. Anstey, V. Anstey, L. Antal, E. Antle, J. Antle, M. Antoine, K. Antonishyn, A. Antunes, H. Aparicio Ramos, P. Appiah, J. Aquila, R. Aranguren, F. Arano, L. Arbour, C. Arcand, L. Archer, J. Argan, M. Arguin, H. Arias, L. Arias, J. Arizaleta, S. Arjomandi, J. Arkley, T. Armfelt, M. Armour, A. Armstrong, D. Armstrong, J. Armstrong, P. Armstrong, R. Armstrong, J. Arnault, B. Arneson, B. Arnold, C. Arnold, J. Arnold, V. Aron, F. Arrieta, M. Arsenault, L. Arthur, A. Arthur Brown, B. Artz, S. Arunachalam, B. Asake, J. Ashe, Z. Ashmore, A. Aslam, R. Aslin, R. Asmundson, S. Aspden, R. Aspden, H. Aspeslet, M. Asselstine, D. Assinger, J. Asso, V. Assohou-Ouattara, F. Assoko-Mve, A. Assoum, S. Assoumane, A. Astalos, R. Astalos, I. Astete, M. 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Blanchette, A. Blanco, G. Blanco, U. Blanco, W. Blanco, S. Blaydes, K. Blencowe, J. Blesa, M. Blinkhorn, R. Blonar, R. Blondin, P. Bluemke, J. Blume, C. Blyan, C. Boadas Salazar, J. Bobbett, H. Bocalan, D. Bochek, R. Bock, G. Boddy, J. Bodell, R. Bodell, S. Bodell, A. Bodnar, K. Bodnar, J. Bodnarchuk, V. Bodnarchuk, B. Bodner, G. Bodner, D. Bodoano, D. Boehmer, D. Boettcher, D. Boettger, M. Boggust, T. Bohach, A. Bohemier, J. Bohlken, N. Bohning, J. Bohorquez, G. Bohrson, J. Boire, J. Boissoneault, C. Boisvert, M. Boisvert, D. Bokota, R. Boksteyn, S. Bolduc, C. Boleski, C. Bolger, G. Bolin, D. Bolster, B. Bolt, J. Bolt, G. Bolzon, J. Bonami-McRae, K. Bond, N. Bond, S. Bond, T. Bond, E. Bondarenko, T. Bondaruk, C. Bonebrake, A. Bonilla, E. Bonnefon, C. Bonogofski, A. Bonwick, T. Bonwick, R. Booker, S. Booker, P. Booklall, J. Boomgaarden, A. Boone, B. Boone, C. Boos, K. Booth, B. Borbely, A. Borbon, K. Bordeleau, R. Borg, C. Borgel, O. Borghesan, C. Borgland, J. Borkowski, D. Borle, M. 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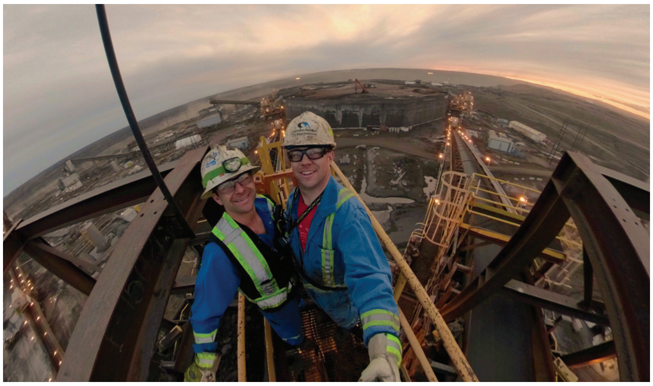

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Stevens, J. Stevens, N. Stevens, R. Stevens, A. Stevens-Dicks, A. Stevenson, H. Stevenson, N. Stevenson, R. Stevenson, T. Stevers, R. Steward, C. Stewart, D. Stewart, I. Stewart, J. Stewart, L. Stewart, M. Stewart, R. Stewart, W. Stickel, R. Stieben, M. Stiefel, D. Stinn, S. Stirling, M. St-Jacques, M. Stobart, D. Stobbe, J. Stober, M. Stockes, C. Stocking, M. Stockton, J. Stokes, C. Stolz, T. Stolz, D. Stone, M. Stone, M. Stordahl, J. Storey, D. Stormo, L. Storsley, B. Stortz, D. Stout, R. Stoutenberg, D. Stoyles, K. Stoyles, S. Strachan, N. Strain, A. Stranaghan, R. Stranberg, W. Strand, J. Strandquist, C. Strang, D. Strang, R. Strang, N. Strantz, B. Stratichuk, D. Stratmoen, M. Street, S. Street, C. Stretch, R. Stretch, W. Stretch, T. Strickland, R. Striegler, J. Strilchuk, M. Stroh, J. Strong, R. Strong, M. Stronski, R. Struski, D. Strynadka, D. Stuart, L. Stuart, P. Stuart, C. Stubbs, G. Stuber, V. Stuckey, L. Stuckless, N. Stuckless, R. Stuckless, T. Stuckless, J. Stuebing, F. Sturge, J. Sturge, P. Sturge, J. Sturgeon, P. Sturgeon, D. Sturrock, A. Styles, L. Su, W. Su, M. Suarez, G. Suarez Caicedo, V. Subasic, I. Subasinghe, V. Subban, J. Subramaniam, R. Subramaniam, S. Suche, R. Sukkel, J. Sullivan, M. Sullivan, R. Sullivan, T. Sullivan, P. Sultanian, B. Summerfelt, C. Summers, E. Summers, T. Sun, X. Sun, U. Sundar, U. Sundaram, P. Sundaravadivelu, C. Surgenor, A. Surugiu, G. Surugiu, C. Sutherland, D. Sutherland, H. Sutherland, K. Sutherland, L. Sutherland, S. Sutherland, C. Suttie, B. Sutton, P. Sutton, S. Sverdahl, T. Svoboda, A. Swain, D. Swain, S. Swain, J. Swampy, D. Swan, M. Swan, J. Swannack, C. Swanson, J. Swanson, N. Swanson, R. Swarnkar, E. Sweeney, S. Sweetapple, C. Swenarchuk, N. Swennumson, D. Swiegocki, E. Switzer, A. Sychak, K. Sydorko, C. Syed, D. Syed, J. Sykes, T. Sylvester, D. Sylvestre, G. Sylvestre, B. Symington, A. Symons, M. Symons, T. Sypher-Michel, D. Syrnyk, N. Szalay, E. Szeto, C. Szmata, A. Szoke, C. Szpecht, D. Sztukowski, D. Sztym, C. Szutiak, K. Szydlik, J. Ta, V. Ta, C. Tacadena, M. Tade, D. Taggart, A. Taghipour, P. Taiani, M. Tainsh, D. Tainton, D. Tait, O. Tait, G. Tait, J. Taite, A. Tajik, D. Tajiri, D. Takala, S. Takala, G. Talati, S. Talati, C. Talbot, J. Talbot, M. Talerico, C. Tallack, D. Tallas, B. Talma, K. Tam, N. Taman, B. Tamas, B. Tan, C. Tan, K. Tan, S. Tan, M. Tanasescu, B. Tancowny, E. Tang, L. Tang, X. Tang, G. Tangonan, T. Tanigami, J. Tanner, H. Tansley, M. Tapley, G. Tapp, C. Tarache, A. Tarasenco, C. Tardif, G. Tarditi, K. Targett, B. Tarkowski, M. Taron, D. Tarrant, B. Tasek, J. Tatarin, N. Tavassoli, A. Taylor, B. Taylor, G. Taylor, J. Taylor, K. Taylor, L. Taylor, M. Taylor, N. Taylor, P. Taylor, R. Taylor, S. Taylor, W. Taylor, C. Taylor, H. Taylor, B. Teare, C. Tearoe, M. Teeple, A. Tegnander, S. Tejpar, A. Telan, M. Teleptean, R. Tellier, B. Temesgen, J. Temple, C. Templeton, K. Tenney, J. Teppin, G. Teske, C. Tessier, W. Teszeri, W. Tetachuk, C. Tetreau, J. Tettensor, B. Tetz, J. Tetz, S. Tetz, I. Tewfik, E. Tezcan, F. Thaddaues, L. Thai, T. Tham, J. Thauberger, S. Theoret, G. Therriault, G. Therriault, B. Thevarajah, W. Thew, R. Thibodeau, C. Thiessen, J. Thiessen, L. Thiessen, T. Thiessen, W. Thijs, P. Thimaiah, S. Thind, M. Thoen, D. Thomas, E. Thomas, L. Thomas, M. Thomas, N. Thomas, P. Thomas, S. Thomas, J. Thomas Cotton, C. Thompson, D. Thompson, E. Thompson, H. Thompson, I. Thompson, J. Thompson, L. Thompson, R. Thompson, S. Thompson, T. Thompson, J. Thomsen, P. Thomsen, A. Thomson, K. Thomson, M. Thomson, P. Thomson, S. Thomson, T. Thomson, J. Thomson, W. Thomson, K. Thorburn, T. Thorburne, W. Thorburne, J. Thorleifson, B. Thorn, A. Thorne, D. Thorne, L. Thorne, B. Thornhill, E. Thornton, K. Thornton, N. Thorp, K. Thors, E. Thunaes, D. Thurman, M. Thyer, T. Tian, M. Tiedje, S. Tieh, P. Tieu, B. Tiffin, T. Tigere, D. Tillapaugh, D. Tilley, K. Tilley, M. Tilley, K. Tillotson, T. Tillotson, B. Timmons, S. Timothy, N. Tindall, M. Tineo, D. Tipper, B. Titus, D. Tiwary, R. Tiwary, C. Tkach, D. Tkachuk, E. To, B. Tobin, K. Tobin, V. Tobin, K. Tobler, B. Todd, C. Todd, S. Todd, W. Todoschuk, T. Tolen, D. Tomar, B. Tomchuk, G. Tomchuk, D. Tomiuk, C. Tomlinson, A. Tomszak, N. Tomte, W. Tong, M. Tonon, S. Tookey, V. Topacio, S. Topolnitsky, K. Tordon, L. Torrance, P. Torrance, C. Torraville, F. Torraville, J. Torraville, N. Torres, D. Torriero, D. Toth, K. Totten, D. Touchette, S. Touchette, D. Toullelan, K. Tourand, T. Tourand, M. Townsend, D. Tozer, O. Tozser, C. Tran, D. Tran, R. Trant, C. Trapp, L. Trautman, M. Travers, J. Traverse, M. Traverse, P. Traverse, J. Tredger, D. Tredou, G. Treen, J. Treen, J. Trelinski, W. Trelinski, J. Treliving, L. Tremblay, M. Tremblay, C. Tremblett, M. Tremblett, W. Tremblett, S. Tremel, J. Trenholm, D. Trentham, J. Trieu, J. Trieu-Ly, J. Trifaux, S. Trifonov, W. Trigger, A. Trinh, D. Trinh, J. Trinier, E. Trip-De-Roche, E. Triumbari, C. Troake, B. Troy, P. Troy, J. Trto, J. Trudeau, R. Trudeau, B. Trumpf, A. Truong, S. Truong, H. Tsagalas, S. Tschetters, C. Tse, Y. Tse, P. Tso, Y. Tu, A. Tuck, B. Tucker, D. Tucker, J. Tucker, R. Tucker, A. Tuico, D. Tuite, S. Tulan, B. Tulk, J. Tulk, L. Tulk, B. Tulloch, N. Tulloch, B. Tumbach, M. Tunke, T. Tupper, T. Turbide, D. Turcotte, J. Turcotte, D. Turgeon, T. Turgeon, B. Turner, C. Turner, D. Turner, J. Turner, S. Turner, D. Turpin, T. Turpin, V. Turska, S. Turton, A. Turtulga, S. Tutkaluk, W. Tutt, R. Tuttle, S. Tuttle, I. Tutto, L. Tuttosi, T. Twist, P. Twomey, D. Twyne, O. Tyan, A. Tyler, M. Tyler, W. Tymchuk, D. Tymchyna, R. Tymchyna, Z. Tymo, N. Tynan, S. Tyrell, G. Tyrer, C. Tyssen, J. Uddin, D. Uduwara Merennage, T. Uhrich, S. Ulloa, C. Ulrich, E. Ulrich, J. Umali, O. Umana, U. Umoh, L. Underhill, K. Underwood, N. Underwood, R. Underwood, T. Ung, D. Unger, K. Unger, B. Unrath, L. Unrau, H. Unruh, P. Unruh, S. Upadhyay, U. Upadhyaya, C. Upham, M. Uponi, D. Urban, L. Urbina, J. Urdaneta, C. Urlacher, A. Ustariz, K. Uyanwune, B. Vacheresse, R. Vachon, S. Vadnai, K. Vaideswaran, G. Valencia, A. Valentine, D. Valin, T. Valin, A. Valiquette, G. Valiquette, J. Valle, L. Vallee, M. Vallee, W. Vallee, G. Vallis, A. Valmadrid, K. Van Buskirk, A. Van De Reep, C. Van de Reep, W. Van den Oever, M. van der Burgh, N. Van Der Merwe, V. Van Der Merwe, A. Van Donkervoort, H. Van Dyck, M. Van Dyk, B. van Dyke, N. Van Dyke, P. van Eerde, D. Van Genne, L. Van Genne, L. van Heerden, S. Van Jaarsveld, J. Van Nes, C. van Niekerk, S. Van Rensburg, D. Van Rootselaar, C. Van Schoor, R. Van Steinburg, R. van Zanden, M. Vanberg, D. Vanbocquestal, M. Vance, J. Vancoughnett, K. Vandaelle, J. Vandeligt, R. Vandemark, T. Vandemark, D. Vandenberg, G. Vander Veen, J. Vanderkley, T. Vandermeer, J. Vandervoort, G. van't Wout, C. Vare, S. Varey, M. Varga, D. Varty, N. Vaschetto, A. Vashisht, A. Vasquez, M. Vasquez-Placid, J. Vasseur, R. Vassov, A. Vaters, R. Vaudan, N. Vaughan, A. Vaughan, J. Veale, O. Vedmedenko, S. Vekved, B. Velagapudi, B. Velichka, S. Venkatesh, R. Venn, D. Venning, J. Vera, L. Verbaas, D. Verbeek, D. Verbicky, M. Verburg, A. Verge, J. Verge, M. Verge, N. Veriotes, S. Veroba, J. Verot, B. Verreau, D. Versnick-Brown, K. Veysey, J. Vezina, E. Viale Tudela, C. Viana, G. Vibert, J. Vicic, S. Vicic, N. Vick, K. Vierboom, A. Vihristencu, G. Viljoen, R. Villanueva, J. Villemaire, M. Villemaire, C. Villemere, P. Villeneuve, R. Vincent, S. Vineham, B. Viney, R. Vinkle, B. Vinoly, J. Virtanen, G. Virus, K. Virus, A. Visotto, R. Vivian, N. Vizcuna Alvarado, R. Vloet, M. Vogan, S. Voight, V. Volk, B. Volkmann, R. Volkmann, J. Vollman, W. Volschenk, E. von Hertzberg, L. Vondermuhll, B. Von-Grat, A. Vosburgh, G. Vose, A. Votta, A. Vredegoor, J. Vrolson, N. Vucic, J. Vuong, Q. Vuong, B. Vye, G. Wack, E. Waddell, C. Wadden, K. Waddy, J. Wade, W. Wade, T. Wagil, C. Wagner, D. Wagner, G. Wagner, J. Wagner, K. Wagner, N. Wagner, M. Wahl, N. Waite, F. Wajih, D. Wakaruk, L. Wakaruk, L. Wakefield, A. Walchuk, D. Waldner, D. Waldo, K. Waldron, A. Walintschek, C. Walker, D. Walker, G. Walker, J. Walker, S. Walker, T. Walker, K. Walko, D. Wall, S. Wall, A. Wallace, C. Wallace, E. Wallace, H. Wallace, K. Wallace, V. Wallace, G. Wallin, N. Wallin, M. Wallis, V. Wallwork, T. Walraven, A. Walsh, B. Walsh, D. Walsh, E. Walsh, P. Walsh, R. Walsh, S. Walsh, T. Walsh, W. Walsh, L. Walter, A. Walters, C. Walters, D. Walters, J. Walters, T. Waltmans, K. Wambolt, N. Wan, D. Wanchuk, C. Wang, H. Wang, J. Wang, L. Wang, R. Wang, S. Wang, T. Wang, W. Wang, X. Wang, Y. Wang, Z. Wang, B. Wangler, D. Wannas, L. Waquan, S. Waquan, T. Warburton, D. Ward, E. Ward, K. Ward, M. Ward, D. Warford, W. Warholik, J. Waring, C. Wark, W. Warman, F. Warraich, G. Warren, J. Warren, K. Warren, R. Warren, S. Warren, D. Warrington, M. Warsame, K. Warwaruk, A. Wasikowski, P. Wassell, C. Wasylciw, W. Wasylucha, D. Waterfield, S. Waterfield, C. Waters, R. Waters, D. Watson, G. Watson, J. Watson, K. Watson, M. Watson, S. Watson, D. Watt, G. Watt, B. Watton, B. Watts, J. Watts, B. Weatherby, D. Weatherby, C. Weatherhead, H. Weaver, L. Weaving, A. Webb, G. Webb, P. Webb, R. Webb, B. Webber, D. Webber, J. Webber, O. Websdale, K. Webster, D. Weed, E. Weening, E. Weenink, B. Wegenast, B. Wei, Z. Wei, J. Weibrecht, J. Weigl, J. Weik, D. Weimer, C. Weiner, C. Weingarten, R. Weir, G. Weisbeck, R. Weisbrot, M. Weishaar, C. Weiss, J. Weller, B. Wellman, A. Wells, C. Wells, D. Wells, E. Wells, L. Wells, N. Wells, R. Wells, S. Wells, T. Wells, K. Wellwood, A. Welsh, J. Welsh, W. Welte, W. Welygan, Z. Wen, G. Weng, M. Wenger, P. Wenger, J. Wenisch, J. Wentworth, K. Wenzel, D. Werbowy, D. Werle, C. Werner, N. Wert, B. Weslake, D. West, R. West, M. Westad, D. Westbrook, K. Westland, R. Westland, B. Wetthuhn, K. Whalen, D. Wheating, L. Wheating, J. Wheaton, S. Wheaton, C. Wheaton, B. Wheeler, C. Wheeler, J. Wheeler, K. Wheeler, L. Wheeler, N. Wheeler, A. Wheeler, C. Whelan, D. Whelan, K. Whelan, R. Whelan, R. Whelan-Maloney, G. Whelen, L. Whillans, A. White, B. White, D. White, F. White, G. White, H. White, J. White, K. White, L. White, M. White, N. White, P. White, R. White, S. White, T. White, J. Whitehead, L. Whitehead, T. Whitehead, V. Whitehead, D. Whitehouse, K. Whiteknife, N. Whiteknife, C. Whiteley, A. Whiteside, C. Whitford, H. Whitmore, M. Whittaker, A. Whitten, H. Whitten, A. Whitwell, R. Whyte, A. Wickins, C. Wickwire, A. Wiebe, D. Wiebe, M. Wiebe, T. Wiebe, D. Wiege, T. Wielgus, S. Wiens, B. Wiesener, C. Wietzel, Z. Wigglesworth, S. Wight, T. Wight, S. Wightman, D. Wijesingha, C. Wilbee, M. Wilcox, R. Wild, D. Wilde, E. Wildeman, M. Wilders, D. Wiles, R. Wiles, C. Wilk, T. Wilk, C. Wilkes, C. Wilkin, L. Wilkin, D. Wilkins, D. Wilkinson, J. Wilkinson, K. Wilkinson, P. Will, D. Willard, E. Willard, B. Willburn, A. Willcott, B. Willcott, J. Willems, C. Willey, R. Willey, A. Williams, B. Williams, C. Williams, G. Williams, L. Williams, M. Williams, N. Williams, P. Williams, R. Williams, S. Williams, T. Williams, W. Williams, C. Williamson, D. Williamson, K. Williamson, M. Williamson, J. Williamson, J. Willick, M. Willis, J. Williston, D. Willms, S. Wills, C. Willson, D. Willson, M. Wilschut, B. Wilson, C. Wilson, D. Wilson, G. Wilson, H. Wilson, J. Wilson, K. Wilson, M. Wilson, R. Wilson, S. Wilson, W. Wilson, A. Winfield, B. Wingate, A. Wingert, J. Winia, B. Winiarz, I. Winland, R. Winnicky, T. Winquist, D. Winship, R. Winslow, J. Winsor, O. Winsor, A. Winter, T. Winter, G. Winters, R. Winters, G. Wirachowsky, J. Wirachowsky, T. Wire, M. Wiseman, W. Wiseman, P. Wiseman, I. Wishart, M. Witmer, Z. Witt, B. Wittenborn, C. Wlad, A. Wlos, D. Woitas, J. Woitas, T. Woitte, R. Wojtowicz, S. Wolf, D. Wolfe, J. Wolfe, D. Wollum, C. Woloshyn, J. Wolstenholme, B. Wolstoncroft, J. Wolter, R. Wolters, A. Wong, J. Wong, L. Wong, N. Wong, T. Wong, C. Woo, J. Woo, K. Woo, L. Woo, G. Wood, J. Wood, L. Wood, P. Wood, R. Wood, R. Woodburne, J. Woodd, M. Woodfin, S. Woodfine, N. Woodford, S. Woodford, T. Woodford, A. Woodger, M. Woodhead, D. Woods, J. Woods, S. Woods, T. Woods, M. Woodske, J. Wooldridge, B. Wooley, S. Woolfitt, T. Woolley, R. Woolner, R. Wootton, M. Workman, M. Workun, M. Woroniuk, C. Worthman, P. Wortman, H. Wossey Ogandaga Mbourou, J. Wotten, B. Wright, C. Wright, J. Wright, L. Wright, S. Wright, R. Wright, G. Wrinn, B. Wu, C. Wu, D. Wu, J. Wu, M. Wu, S. Wu, Y. Wu, B. Wurzer, K. Wutzke, G. Wyman, G. Wyndham, D. Wyshynski, L. Wysocki, S. Wytrychowski, Y. Xia, Y. Xie, C. Xu, H. Xu, J. Xu, Q. Xu, Z. Xu, M. Xue, D. Yackel, N. Yagolnyk, K. Yakemchuk, K. Yakimowich, L. Yakiwchuk, B. Yang, D. Yang, J. Yang, L. Yang, X. Yang, D. Yanke, M. Yanota, L. Yao, K. Yao, H. Yare, A. Yaremko, R. Yarmuch, J. Yaroslawsky, S. Yasin, M. Yaychuk, P. Yazdani, B. Ye, B. Yeboue, B. Yee, G. Yee, R. Yee, C. Yen, C. Yeoman, D. Yep, P. Yepes, J. Yeske, O. Ying, Y. Ying, Z. Ying, J. Yip, K. Yip, L. Yip, M. Yniguez, L. Yogasundaram, F. Yohannes, R. Yong, F. York, P. York, A. Yoshikawa, X. You, D. Youck, B. Young, C. Young, D. Young, E. Young, G. Young, J. Young, K. Young, L. Young, M. Young, P. Young, S. Young, T. Young, N. Younis, K. Yousaf, R. Yowney, E. Yu, G. Yu, J. Yu, M. Yu, C. Yuen, D. Yuill, J. Yuill, R. Yuristy, R. Zabek, A. Zacharias, C. Zacharias, T. Zachoda, C. Zackowski, J. Zaderey, N. Zaderey, B. Zagoruy, S. Zagozewski, E. Zahacy, A. Zahorszky, B. Zaitsoff, D. Zambrano Suarez, B. Zandstra, C. Zaparyniuk, H. Zarazun, D. Zarowny, K. Zarowny, K. Zayac, D. Zazula, R. Zazula, S. Zbrodoff, T. Zeiser, I. Zelazny, D. Zelman, B. Zembik, D. Zemlak, A. Zenide, W. Zeniuk, G. Zeran, J. Zerpa, K. Zerr, M. Zerr, S. Zgurski, Y. Zhai, B. Zhang, J. Zhang, M. Zhang, Q. Zhang, W. Zhang, X. Zhang, Y. Zhang, Z. Zhang, B. Zhao, L. Zhao, G. Zheng, S. Zheng, W. Zheng, H. Zhou, Q. Zhou, X. Zhou, Y. Zhou, L. Zhu, W. Zhu, E. Zhuromsky, P. Zia, S. Ziadeh, A. Zielke, F. Zilahy, D. Zilinski, E. Zilinski, D. Zimmer, E. Zimmer, L. Zseder, A. Zubot, J. Zuk, S. Zukanovic, N. Zukiwski, S. Zukowski, D. Zurabyan, J. Zwolak, S. Zwyer

2018 Year-End Reserves

DETERMINATION OF RESERVES

For the year ended December 31, 2018, the Company retained Independent Qualified Reserves Evaluators (IQREs), Sproule Associates Limited, Sproule International Limited and GLJ Petroleum Consultants Limited, to evaluate and review all of the Company's proved and proved plus probable reserves. The IQREs conducted the evaluation and review in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook. The reserves disclosure is presented in accordance with NI 51-101 requirements using forecast prices and escalated costs.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with the IQREs as to the Company's reserves. All reserves values are Company Gross unless stated otherwise.

Corporate Total

- Canadian Natural's 2018 performance has resulted in another year of excellent finding and development costs:
  - Finding, Development and Acquisition ("FD&A") costs, excluding changes in Future Development Capital ("FDC"), are $3.11/BOE for proved reserves and $2.31/BOE for proved plus probable reserves.
  - FD&A costs, including changes in FDC, are $9.39/BOE for proved reserves and $10.79/BOE for proved plus probable reserves.
- Proved reserves additions and revisions replaced 2018 production by 359%. Proved plus probable reserves additions and revisions replaced 2018 production by 485%.
- Proved reserves increased 12% to 9.893 billion BOE with reserves additions and revisions of 1.416 billion BOE. Proved plus probable reserves increased 13% to 13.382 billion BOE with reserves additions and revisions of 1.910 billion BOE.
- The proved BOE reserves life index is 27.7 years and the proved plus probable BOE reserves life index is 37.4 years.
- Proved developed producing reserves additions and revisions are 1.109 billion BOE, replacing 2018 production by 281%. The total proved developed producing BOE reserves life index is 21.3 years.
- Recycle ratios are 8.7 times and 11.8 times for proved and proved plus probable reserves respectively, excluding changes in FDC, recycle ratios are 2.9 times and 2.5 times for proved and proved plus probable reserves respectively, including changes in FDC.
- The net present value of future net revenues, before income tax, discounted at 10%, increased 19% to $106.6 billion for proved reserves and increased 14% to $131.0 billion for proved plus probable reserves. The net present value for proved developed producing reserves increased 24% to $84.2 billion reflecting the impact of the Horizon South Pit addition and decreased production expenses at AOSP.

North America Exploration and Production

- Canadian Natural's North America conventional and thermal assets delivered strong reserves results in 2018:
  - FD&A costs, excluding changes in FDC, are $6.51/BOE for proved reserves and $3.50/BOE for proved plus probable reserves.
  - FD&A costs, including changes in FDC, are $7.23/BOE for proved reserves and $10.54/BOE for proved plus probable reserves.
- Proved reserves additions and revisions replaced 187% of 2018 production. Proved plus probable reserves additions and revisions replaced 349% of 2018 production.
- Proved reserves increased 6% to 3.588 billion BOE. This is comprised of 2.488 billion bbl of crude oil, bitumen, and NGL reserves and 6.597 Tcf of natural gas reserves.
- Proved plus probable reserves increased 10% to 6.027 billion BOE. This is comprised of 4.421 billion bbl of crude oil, bitumen, and NGL reserves and 9.633 Tcf of natural gas reserves.
- Proved reserves additions and revisions are 341 million bbl of crude oil, bitumen and NGL and 411 Bcf of natural gas. Proved plus probable reserves additions and revisions are 654 million bbl of crude oil, bitumen and NGL and 657 Bcf of natural gas.
- The proved BOE reserves life index is 18.9 years and the proved plus probable BOE reserves life index is 31.7 years.

North America Oil Sands Mining and Upgrading

- Canadian Natural's Oil Sands Mining and Upgrading segment delivered strong reserves results in 2018:
  - FD&A costs, excluding changes in FDC, are $1.47/bbl for proved reserves and $1.29/bbl for proved plus probable reserves.
  - FD&A costs, including changes in FDC, are $10.49/bbl for proved reserves and $11.33/bbl for proved plus probable reserves.
- Proved SCO reserves increased 16% to 6.091 billion bbl. Proved plus probable SCO reserves increased 16% to 7.032 billion bbl.
- SCO reserves account for 62% of the Company's proved BOE reserves and 53% of the proved plus probable BOE reserves.

International Exploration and Production

- North Sea proved reserves are unchanged at 124 million BOE and proved plus probable reserves increased 4% to 193 million BOE.
- Offshore Africa proved reserves increased 5% to 90 million BOE and proved plus probable reserves decreased 4% to 131 million BOE.

Summary of Company Gross Reserves
As of December 31, 2018
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	114	97	248	311	6,091	3,477	101	7,541
Developed Non-Producing	14	16	–	123	–	326	10	218
Undeveloped	66	69	57	1,106	–	2,794	156	1,920
Total Proved	194	182	305	1,540	6,091	6,597	267	9,679
Probable	74	70	140	1,519	941	3,036	130	3,379
Total Proved plus Probable	268	252	445	3,059	7,032	9,633	397	13,058
North Sea								
Proved								
Developed Producing	34					23		38
Developed Non-Producing	4					–		4
Undeveloped	81					4		82
Total Proved	119					27		124
Probable	67					11		69
Total Proved plus Probable	186					38		193
Offshore Africa								
Proved								
Developed Producing	41					17		44
Developed Non-Producing	–					–		–
Undeveloped	45					11		46
Total Proved	86					28		90
Probable	35					35		41
Total Proved plus Probable	121					63		131
Total Company								
Proved								
Developed Producing	189	97	248	311	6,091	3,517	101	7,623
Developed Non-Producing	18	16	–	123	–	326	10	222
Undeveloped	192	69	57	1,106	–	2,809	156	2,048
Total Proved	399	182	305	1,540	6,091	6,652	267	9,893
Probable	176	70	140	1,519	941	3,082	130	3,489
Total Proved plus Probable	575	252	445	3,059	7,032	9,734	397	13,382

Summary of Company Net Reserves
As of December 31, 2018
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	101	81	189	252	5,125	3,183	80	6,358
Developed Non-Producing	12	14	–	104	–	303	8	189
Undeveloped	56	59	48	911	(8)	2,519	131	1,616
Total Proved	169	154	237	1,267	5,117	6,005	219	8,163
Probable	61	57	100	1,210	761	2,676	104	2,740
Total Proved plus Probable	230	211	337	2,477	5,878	8,681	323	10,903
North Sea								
Proved								
Developed Producing	34					23		38
Developed Non-Producing	4					–		4
Undeveloped	81					4		82
Total Proved	119					27		124
Probable	67					11		69
Total Proved plus Probable	186					38		193
Offshore Africa								
Proved								
Developed Producing	36					12		38
Developed Non-Producing	–					–		–
Undeveloped	36					9		38
Total Proved	72					21		76
Probable	26					23		30
Total Proved plus Probable	98					44		106
Total Company								
Proved								
Developed Producing	171	81	189	252	5,125	3,218	80	6,434
Developed Non-Producing	16	14	–	104	–	303	8	193
Undeveloped	173	59	48	911	(8)	2,532	131	1,736
Total Proved	360	154	237	1,267	5,117	6,053	219	8,363
Probable	154	57	100	1,210	761	2,710	104	2,839
Total Proved plus Probable	514	211	337	2,477	5,878	8,763	323	11,202

Reconciliation of Company Gross Reserves
As of December 31, 2018
Forecast Prices and Costs

PROVED	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
December 31, 2017	171	198	327	1,350	5,264	6,730	229	8,661
Discoveries	–	–	–	–	–	–	–	–
Extensions	12	14	–	171	808	122	9	1,034
Infill Drilling	17	6	–	4	–	470	38	143
Improved Recovery	–	–	1	2	–	3	–	4
Acquisitions	3	2	–	–	–	82	4	22
Dispositions	–	(5)	–	–	–	(3)	–	(5)
Economic Factors	–	1	1	–	–	(305)	(4)	(53)
Technical Revisions	10	(2)	(1)	52	175	42	6	247
Production	(19)	(32)	(23)	(39)	(156)	(544)	(15)	(374)
December 31, 2018	**194**	**182**	**305**	**1,540**	**6,091**	**6,597**	**267**	**9,679**
North Sea								
December 31, 2017	120					21		124
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	1					–		1
Improved Recovery	–					–		–
Acquisitions	8					–		8
Dispositions	–					–		–
Economic Factors	5					–		5
Technical Revisions	(6)					18		(3)
Production	(9)					(12)		(11)
December 31, 2018	**119**					**27**		**124**
Offshore Africa								
December 31, 2017	83					20		86
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	10					17		13
Production	(7)					(9)		(9)
December 31, 2018	**86**					**28**		**90**
Total Company								
December 31, 2017	374	198	327	1,350	5,264	6,771	229	8,871
Discoveries	–	–	–	–	–	–	–	–
Extensions	12	14	–	171	808	122	9	1,034
Infill Drilling	18	6	–	4	–	470	38	144
Improved Recovery	–	–	1	2	–	3	–	4
Acquisitions	11	2	–	–	–	82	4	30
Dispositions	–	(5)	–	–	–	(3)	–	(5)
Economic Factors	5	1	1	–	–	(305)	(4)	(48)
Technical Revisions	14	(2)	(1)	52	175	77	6	257
Production	(35)	(32)	(23)	(39)	(156)	(565)	(15)	(394)
December 31, 2018	**399**	**182**	**305**	**1,540**	**6,091**	**6,652**	**267**	**9,893**

Reconciliation of Company Gross Reserves
As of December 31, 2018
Forecast Prices and Costs

PROBABLE	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
December 31, 2017	68	74	142	1,230	799	2,790	106	2,884
Discoveries	–	–	–	–	–	–	–	–
Extensions	4	7	–	59	71	93	5	162
Infill Drilling	6	2	–	1	–	391	22	97
Improved Recovery	1	–	2	2	–	1	–	4
Acquisitions	1	1	–	403	–	22	1	410
Dispositions	–	(1)	–	–	–	(2)	–	(2)
Economic Factors	(1)	–	–	–	–	(104)	(1)	(19)
Technical Revisions	(5)	(13)	(4)	(176)	71	(155)	(3)	(157)
Production	–	–	–	–	–	–	–	–
December 31, 2018	**74**	**70**	**140**	**1,519**	**941**	**3,036**	**130**	**3,379**
North Sea								
December 31, 2017	60					11		61
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	5					–		5
Dispositions	–					–		–
Economic Factors	(5)					–		(5)
Technical Revisions	7					–		8
Production	–					–		–
December 31, 2018	**67**					**11**		**69**
Offshore Africa								
December 31, 2017	42					47		50
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(7)					(12)		(9)
Production	–					–		–
December 31, 2018	**35**					**35**		**41**
Total Company								
December 31, 2017	170	74	142	1,230	799	2,848	106	2,995
Discoveries	–	–	–	–	–	–	–	–
Extensions	4	7	–	59	71	93	5	162
Infill Drilling	6	2	–	1	–	391	22	97
Improved Recovery	1	–	2	2	–	1	–	4
Acquisitions	6	1	–	403	–	22	1	415
Dispositions	–	(1)	–	–	–	(2)	–	(2)
Economic Factors	(6)	–	–	–	–	(104)	(1)	(24)
Technical Revisions	(5)	(13)	(4)	(176)	71	(167)	(3)	(158)
Production	–	–	–	–	–	–	–	–
December 31, 2018	**176**	**70**	**140**	**1,519**	**941**	**3,082**	**130**	**3,489**

Reconciliation of Company Gross Reserves
As of December 31, 2018
Forecast Prices and Costs

PROVED PLUS PROBABLE	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
December 31, 2017	239	272	469	2,580	6,063	9,520	335	11,545
Discoveries	–	–	–	–	–	–	–	–
Extensions	16	21	–	230	879	215	14	1,196
Infill Drilling	23	8	–	5	–	861	60	240
Improved Recovery	1	–	3	4	–	4	–	8
Acquisitions	4	3	–	403	–	104	5	432
Dispositions	–	(6)	–	–	–	(5)	–	(7)
Economic Factors	(1)	1	1	–	–	(409)	(5)	(72)
Technical Revisions	5	(15)	(5)	(124)	246	(113)	3	90
Production	(19)	(32)	(23)	(39)	(156)	(544)	(15)	(374)
December 31, 2018	**268**	**252**	**445**	**3,059**	**7,032**	**9,633**	**397**	**13,058**
North Sea								
December 31, 2017	180					32		185
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	1					–		1
Improved Recovery	–					–		–
Acquisitions	13					–		13
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	1					18		5
Production	(9)					(12)		(11)
December 31, 2018	**186**					**38**		**193**
Offshore Africa								
December 31, 2017	125					67		136
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	3					5		4
Production	(7)					(9)		(9)
December 31, 2018	**121**					**63**		**131**
Total Company								
December 31, 2017	544	272	469	2,580	6,063	9,619	335	11,866
Discoveries	–	–	–	–	–	–	–	–
Extensions	16	21	–	230	879	215	14	1,196
Infill Drilling	24	8	–	5	–	861	60	241
Improved Recovery	1	–	3	4	–	4	–	8
Acquisitions	17	3	–	403	–	104	5	445
Dispositions	–	(6)	–	–	–	(5)	–	(7)
Economic Factors	(1)	1	1	–	–	(409)	(5)	(72)
Technical Revisions	9	(15)	(5)	(124)	246	(90)	3	99
Production	(35)	(32)	(23)	(39)	(156)	(565)	(15)	(394)
December 31, 2018	**575**	**252**	**445**	**3,059**	**7,032**	**9,734**	**397**	**13,382**

Reserves Notes:

(1) Company Gross reserves are working interest share before deduction of royalties and excluding any royalty interests.
(2) Company Net reserves are working interest share after deduction of royalties and including any royalty interests.
(3) BOE values may not calculate due to rounding.
(4) Forecast pricing assumptions utilized by the Independent Qualified Reserves Evaluators in the reserves estimates were provided by Sproule Associates Limited:

	2019	2020	2021	2022	2023
Crude oil and NGL					
WTI at Cushing (US$/bbl)	63.00	67.00	70.00	71.40	72.83
Western Canada Select (C$/bbl)	59.47	62.31	67.45	69.53	71.66
Canadian Light Sweet (C$/bbl)	75.27	77.89	82.25	84.79	87.39
Cromer LSB (C$/bbl)	75.27	76.89	81.25	83.79	86.39
Edmonton Pentanes+ (C$/bbl)	75.32	80.00	83.75	85.50	87.29
North Sea Brent (US$/bbl)	70.00	72.00	73.00	74.46	75.95
Natural gas					
AECO (C$/MMBtu)	1.95	2.44	3.00	3.21	3.30
BC Westcoast Station 2 (C$/MMBtu)	1.35	1.94	2.60	2.81	2.90
Henry Hub (US$/MMBtu)	3.00	3.25	3.50	3.57	3.64

Note. All prices increase at a rate of 2%/year after 2023. A foreign exchange rate of 0.7700 US$/C$ for 2019 and 0.8000 US$/C$ after 2019 was used in the 2018 evaluation.

(5) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.
(6) Metrics included herein are commonly used in the oil and natural gas industry and are determined by Canadian Natural as set out in the notes below. These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies and may be misleading when making comparisons. Management uses these metrics to evaluate Canadian Natural's performance over time. However, such measures are not reliable indicators of Canadian Natural's future performance and future performance may vary.
(7) Reserves additions and revisions are comprised of all categories of Company Gross reserves changes, exclusive of production.
(8) Reserves replacement or Production replacement ratio is the Company Gross reserves additions and revisions, for the relevant reserves category, divided by the Company Gross production in the same period.
(9) Reserves Life Index is based on the amount for the relevant reserves category divided by the 2019 proved developed producing production forecast prepared by the Independent Qualified Reserves Evaluators.
(10) Finding, Development and Acquisition ("FD&A") costs are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2018 by the sum of total additions and revisions for the relevant reserves category. All values used in the calculation are not rounded.
(11) FD&A costs including changes in Future Development Capital ("FDC") are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2018 and net changes in FDC from December 31, 2017 to December 31, 2018 by the sum of total additions and revisions for the relevant reserves category. FDC excludes all abandonment and reclamation costs. All values used in the calculation are not rounded.
(12) Recycle Ratio is the operating netback ($27.13/BOE for 2018) divided by the FD&A (in $/BOE). Operating netback is production revenues, excluding realized gains and losses on commodity hedging, less royalties, transportation and production expenses, calculated on a per BOE basis.
(13) Abandonment and reclamation costs included in the calculation of the Future Net Revenue (FNR) for 2018 consist of both forecast estimates of abandonment and reclamation costs attributable to future development activity, as well as certain costs already included in the Company's Asset Retirement Obligation (ARO) for development existing as at December 31, 2018. The portion of the Company's estimated ARO included in the reserves FNR is escalated at 2.0% per year after 2019. Specifically, for North America (excluding SCO assets), FNR includes the ARO costs associated with abandonment and reclamation of wells (wells, well sites, well site equipment and pipelines) with assigned reserves. For SCO assets, FNR includes the ARO costs associated with the abandonment and reclamation of the mine site and all mining facilities and for Horizon assets, it also includes abandonment and reclamation of the upgrading facilities. For North Sea and Offshore Africa, FNR includes the ARO costs associated with the abandonment and reclamation of offshore wells and facilities with assigned reserves.

Management's Discussion and Analysis

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Definitions and Abbreviations

AECO	Alberta natural gas reference location
AIF	Annual Information Form
AOSP	Athabasca Oil Sands Project
API	specific gravity measured in degrees on the American Petroleum Institute scale
ARO	asset retirement obligations
bbl	barrel
bbl/d	barrels per day
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
BOE	barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
Bitumen	a naturally occurring solid or semi-solid hydrocarbon consisting mainly of heavier hydrocarbons that are too heavy or thick to flow at reservoir conditions, and recoverable at economic rates using thermal in situ recovery methods
Brent	Dated Brent
C$	Canadian dollars
CAGR	compound annual growth rate
CAPEX	capital expenditures
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
Crude oil	includes light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and synthetic crude oil
CSS	Cyclic Steam Stimulation
EOR	Enhanced Oil Recovery
E&P	Exploration and Production
FPSO	Floating Production, Storage and Offloading Vessel
GHG	greenhouse gas
GJ	gigajoules
GJ/d	gigajoules per day
Horizon	Horizon Oil Sands
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
Mbbl	thousand barrels
Mbbl/d	thousand barrels per day
MBOE	thousand barrels of oil equivalent
MBOE/d	thousand barrels of oil equivalent per day
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
Mcf/d	thousand cubic feet per day
MMbbl	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
NGLs	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
PRT	Petroleum Revenue Tax
SAGD	Steam-Assisted Gravity Drainage
SCO	synthetic crude oil
SEC	United States Securities and Exchange Commission
Tcf	trillion cubic feet
TSX	Toronto Stock Exchange
UK	United Kingdom
US	United States
US GAAP	generally accepted accounting principles in the United States
US$	United States dollars
WCS	Western Canadian Select
WCS Heavy Differential	WCS Heavy Differential from WTI
WTI	West Texas Intermediate reference location at Cushing, Oklahoma

Advisory

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, production expenses, capital expenditures, income tax expenses and other guidance provided throughout this Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of the Company, constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands ("Horizon"), the Athabasca Oil Sands Project ("AOSP"), Primrose thermal projects, the Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the cost and timing of construction and future operations of the North West Redwater bitumen upgrader and refinery, construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas, natural gas liquids ("NGLs") or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market, development and deployment of technology and technological innovations, the assumption of operations at processing facilities, and the "Outlook" section of this MD&A, particularly in reference to the 2019 guidance provided with respect to budgeted capital expenditures, also constitute forward-looking statements. These forward-looking statements are based on annual budgets and multi-year forecasts, and are reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, natural gas and NGLs reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserves and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital expenditures and production expenses); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

The Company's operations have been, and in the future may be, affected by political developments and by national, federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations.

Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this MD&A could also have adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by applicable law, the Company assumes no obligation to update forward-looking statements, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or the Company's estimates or opinions change.

SPECIAL NOTE REGARDING NON-GAAP FINANCIAL MEASURES

This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as: adjusted net earnings (loss) from operations; adjusted funds flow (previously referred to as funds flow from operations); net capital expenditures; adjusted cash production costs; adjusted depreciation, depletion, and amortization; and net asset value. These financial measures are not defined by International Financial Reporting Standards ("IFRS") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings (loss), cash flows from operating activities, and cash flows used in investing activities as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measure adjusted net earnings (loss) from operations is reconciled to net earnings (loss), as determined in accordance with IFRS, in the "Financial and Operational Highlights" section of this MD&A. Additionally, the non-GAAP measure adjusted funds flow is reconciled to cash flows from operating activities, as determined in accordance with IFRS, in the "Financial and Operational Highlights" section of this MD&A. The non-GAAP measure net capital expenditures is reconciled to cash flows used in investing activities, as determined in accordance with IFRS, in the "Net Capital Expenditures" section of this MD&A. The derivation of adjusted cash production costs and adjusted depreciation, depletion and amortization are included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

SPECIAL NOTE REGARDING CURRENCY, FINANCIAL INFORMATION, PRODUCTION AND RESERVES

This MD&A should be read in conjunction with the audited consolidated financial statements and related notes for the year ended December 31, 2018. It should also be read in conjunction with the Company's MD&A for the three months and year ended December 31, 2018, which is incorporated herein by reference. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's consolidated financial statements and this MD&A have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB").

Production volumes, per unit statistics and reserves data are presented throughout this MD&A on a "before royalties" or "company gross" basis, and realized prices are net of blending and feedstock costs and exclude the effect of risk management activities. In addition, reference is made to crude oil and natural gas in common units called barrel of oil equivalent ("BOE"). A BOE is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of this MD&A, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and SCO. Production on an "after royalties" or "company net" basis is also presented for information purposes only.

The following discussion and analysis refers primarily to the Company's 2018 financial results compared to 2017 and 2016, unless otherwise indicated. In addition, this MD&A details the Company's targeted capital program for 2019. Additional information relating to the Company, including its quarterly MD&A for the three months and year ended December 31, 2018, its Annual Information Form for the year ended December 31, 2018, and its audited consolidated financial statements for the year ended December 31, 2018 is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. Detailed guidance on production levels, capital expenditures and production expenses can be found on the Company's website at www.cnrl.com. This MD&A is dated March 6, 2019.

Objectives and Strategy

The Company's objectives are to increase crude oil and natural gas production, reserves, cash flow and net asset value [1] on a per common share basis through the economic development of its existing crude oil and natural gas properties and through the discovery and/or acquisition of new reserves. The Company strives to meet these objectives by having a defined growth and value enhancement plan for each of its products and segments. The Company takes a balanced approach to growth and investments and focuses on creating long-term shareholder value. The Company allocates its capital by maintaining:

- Balance among its products, namely light and medium crude oil and NGLs, primary heavy crude oil, Pelican Lake heavy crude oil [2], bitumen (thermal oil), SCO and natural gas;
- A large, balanced, diversified, high quality, long life low decline asset base;
- Balance among acquisitions, exploitation and exploration; and
- Balance between sources and terms of debt financing and a strong financial position.

(1) Discounted value of crude oil and natural gas reserves plus value of unproved land, less net debt.
(2) Pelican Lake heavy crude oil is 12–17° API oil, which receives medium quality crude netbacks due to lower production expense and lower royalty rates.

The Company's three-phase crude oil marketing strategy includes:

- Blending various crude oil streams with diluents to create more attractive feedstock;
- Supporting and participating in pipeline expansions and/or new additions; and
- Supporting and participating in projects that will increase the downstream conversion capacity for heavy crude oil and bitumen (thermal oil).

Operational discipline, safe, effective and efficient operations, and cost control are fundamental to the Company. By consistently managing costs throughout all cycles of the industry, the Company believes it will achieve continued growth. Effective and efficient operations and cost control are attained by developing area knowledge, and by maintaining high working interests and operator status in its properties.

The Company is committed to maintaining a strong balance sheet and flexible capital structure. The Company believes it has built the necessary financial capacity to complete its growth projects. Additionally, the Company periodically utilizes its risk management hedging program to reduce the risk of volatility in commodity prices and foreign exchange rates and to support the Company's cash flow for its capital expenditure programs.

Strategic accretive acquisitions are a key component of the Company's strategy. The Company has used a combination of internally generated cash flows and debt and equity financing to selectively acquire properties generating future cash flows in its core areas.

Financial and Operational Highlights

($ millions, except per common share amounts)		2018		2017		2016
Product sales	$	**22,282**	$	18,360	$	12,002
Crude oil and NGLs	$	**20,668**	$	16,522	$	10,396
Natural gas	$	**1,614**	$	1,838	$	1,606
Net earnings (loss)	$	**2,591**	$	2,397	$	(204)
Per common share – basic	$	**2.13**	$	2.04	$	(0.19)
– diluted	$	**2.12**	$	2.03	$	(0.19)
Adjusted net earnings (loss) from operations (1)	$	**3,263**	$	1,403	$	(669)
Per common share – basic	$	**2.68**	$	1.19	$	(0.61)
– diluted	$	**2.67**	$	1.19	$	(0.61)
Cash flows from operating activities	$	**10,121**	$	7,262	$	3,452
Adjusted funds flow (2)	$	**9,088**	$	7,347	$	4,293
Per common share – basic	$	**7.46**	$	6.25	$	3.90
– diluted	$	**7.43**	$	6.21	$	3.89
Dividends declared per common share (3)	$	**1.34**	$	1.10	$	0.94
Total assets	$	**71,559**	$	73,867	$	58,648
Total long-term liabilities	$	**34,823**	$	35,953	$	27,289
Cash flows used in investing activities	$	**4,814**	$	13,102	$	3,811
Net capital expenditures (4)	$	**4,731**	$	17,129	$	3,794
Average sales price						
Crude oil and NGLs - Exploration and Production ($/bbl)	$	**46.92**	$	48.57	$	36.93
Natural gas - Exploration and Production ($/Mcf)	$	**2.61**	$	2.76	$	2.32
Oil Sands Mining and Upgrading ($/bbl)	$	**68.61**	$	63.98	$	58.59
Daily production, before royalties (BOE/d)		**1,078,813**		962,264		805,782
Crude oil and NGLs (bbl/d)		**820,778**		685,236		523,873
Natural gas (MMcf/d)		**1,548**		1,662		1,691

(1) Adjusted net earnings (loss) from operations is a non-GAAP measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for the after-tax effects of certain items of a non-operational nature. The Company considers adjusted net earnings (loss) from operations a key measure in evaluating the Company's performance, as it demonstrates the Company's ability to generate after-tax operating earnings from its core business areas. The reconciliation "Adjusted Net Earnings (Loss) from Operations, as Reconciled to Net Earnings (Loss)" is presented in this MD&A. Adjusted net earnings (loss) from operations may not be comparable to similar measures presented by other companies.

(2) Adjusted funds flow (previously referred to as funds flow from operations) is a non-GAAP measure that represents cash flows from operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, abandonment and certain movements in other long-term assets. The Company considers adjusted funds flow a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities" is presented in this MD&A. Adjusted funds flow may not be comparable to similar measures presented by other companies.

(3) On March 6, 2019, the Board of Directors approved an increase in the quarterly dividend to $0.375 per common share, beginning with the dividend payable on April 1, 2019. On February 28, 2018, the Board of Directors approved an increase in the quarterly dividend to $0.335 per common share, beginning with the dividend payable on April 1, 2018. On March 1, 2017, the Board of Directors approved an increase in the quarterly dividend to $0.275 per common share, beginning with the dividend payable on April 1, 2017. On November 2, 2016, the Board of Directors approved an increase in the quarterly dividend to $0.25 per common share, beginning with the dividend payable on January 1, 2017. On March 2, 2016, the Board of Directors declared a quarterly dividend of $0.23 per common share, beginning with the dividend payable on April 1, 2016.

(4) Net capital expenditures is a non-GAAP measure that represents cash flows used in investing activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, investment in other long-term assets, share consideration in business acquisitions (dispositions) and abandonment expenditures. The Company considers net capital expenditures a key measure as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. The reconciliation "Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities" is presented in the "Net Capital Expenditures" section of this MD&A. Net capital expenditures may not be comparable to similar measures presented by other companies.

ADJUSTED NET EARNINGS (LOSS) FROM OPERATIONS, AS RECONCILED TO NET EARNINGS (LOSS)

($ millions)	2018	2017	2016
Net earnings (loss), as reported	**$ 2,591**	$ 2,397	$ (204)
Share-based compensation, net of tax (1)	**(146)**	134	355
Unrealized risk management (gain) loss, net of tax (2)	**(36)**	33	21
Unrealized foreign exchange loss (gain), net of tax (3)	**706**	(821)	(93)
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax (4)	**146**	–	–
Loss (gain) from investments, net of tax (5) (6)	**374**	(11)	(299)
Gain on acquisition, disposition and revaluation of properties, net of tax (7)	**(372)**	(339)	(241)
Derecognition of exploration and evaluation assets, net of tax (8)	**–**	–	13
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (9)	**–**	10	(221)
Adjusted net earnings (loss) from operations	**$ 3,263**	$ 1,403	$ (669)

(1) The Company's employee stock option plan provides for a cash payment option. Accordingly, the fair value of the outstanding vested options is recorded as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings (loss) or are charged to (recovered from) the Oil Sands Mining and Upgrading segment.
(2) Derivative financial instruments are recorded at fair value on the Company's balance sheets, with changes in the fair value of non-designated hedges recognized in net earnings (loss). The amounts ultimately realized may be materially different than those amounts reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil, natural gas and foreign exchange.
(3) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates, partially offset by the impact of cross currency swaps, and are recognized in net earnings (loss).
(4) During 2018, the Company repaid US$600 million of 1.75% notes and US$400 million of 5.90% notes.
(5) The Company's investment in the 50% owned North West Redwater Partnership ("Redwater Partnership") is accounted for using the equity method of accounting. Included in the non-cash loss (gain) from investments is the Company's pro rata share of the Redwater Partnership's accounting loss (gain).
(6) The Company's investments in PrairieSky Royalty Ltd. ("PrairieSky") and Inter Pipeline Ltd. ("Inter Pipeline") have been accounted for at fair value through profit and loss and are measured each period with changes in fair value recognized in net earnings (loss).
(7) During 2018, the Company recorded a pre-tax gain of $16 million ($12 million after-tax) on the disposition of a 30% interest in the exploration right in South Africa. Additionally, the Gabonese Republic approved cessation of production from the Company's Olowi field and associated asset retirement obligations, as well as the terms of termination of the Olowi Production Sharing Contract and the surrender of the permit area back to the Gabonese Republic, resulting in a pre-tax gain on disposition of property of $20 million ($14 million after-tax). The Company also recorded a pre-tax gain of $277 million ($263 million after-tax) related to acquisitions in the North America Exploration and Production segment. Additionally, the Company recorded a pre-tax gain of $120 million ($72 million after-tax) on the acquisition of the remaining interest at Ninian in the North Sea and a pre-tax gain of $19 million ($11 million after-tax) relating to the revaluation of the Company's previously held interest at Ninian. During 2017, the Company recorded a pre-tax revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in a pipeline system. Additionally, the Company recorded a pre and after-tax gain of $230 million on the acquisition of a direct and indirect 70% interest in AOSP and other assets from Shell Canada Limited and certain subsidiaries ("Shell") and an affiliate of Marathon Oil Corporation ("Marathon"), and a pre-tax gain of $35 million ($26 million after-tax) on the disposition of certain exploration and evaluation assets in the North America segment. During 2016, the Company recorded a pre and after-tax gain of $218 million on the disposition of Midstream property, plant and equipment. Additionally, the Company recorded a pre-tax gain of $32 million ($23 million after-tax) on the disposition of certain exploration and evaluation assets.
(8) During 2016, in connection with the Company's notice of withdrawal from Block CI-12 in Côte d'Ivoire, Offshore Africa, the Company derecognized $18 million ($13 million after-tax) of exploration and evaluation assets through depletion, depreciation and amortization expense.
(9) All substantively enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's balance sheets in determining deferred income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings (loss) during the period the legislation is substantively enacted. During 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by $10 million. During 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of $107 million. In addition, the UK government also enacted tax rate reductions relating to Petroleum Revenue Tax ("PRT"), resulting in a decrease in the Company's net deferred income tax liability of $114 million.

ADJUSTED FUNDS FLOW, AS RECONCILED TO CASH FLOWS FROM OPERATING ACTIVITIES (1)

($ millions)	2018	2017	2016
Cash flows from operating activities	**$ 10,121**	$ 7,262	$ 3,452
Net change in non-cash working capital	**(1,346)**	(299)	542
Abandonment expenditures (2)	**290**	274	267
Other (3)	**23**	110	32
Adjusted funds flow	**$ 9,088**	$ 7,347	$ 4,293

(1) Adjusted funds flow was previously referred to as funds flow from operations.
(2) The Company includes abandonment expenditures in "Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities" in the "Net Capital Expenditures" section of this MD&A.
(3) Includes certain movements in other long-term assets.

CONSOLIDATED NET EARNINGS (LOSS) AND ADJUSTED NET EARNINGS (LOSS)

For 2018, the Company reported net earnings of $2,591 million compared with net earnings of $2,397 million for 2017 (2016 – $204 million net loss). Net earnings for 2018 included net after-tax expenses of $672 million related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of realized foreign exchange losses on repayments of long-term debt, the loss (gain) from investments, gain on acquisition, disposition and revaluation of properties, derecognition of exploration and evaluation assets and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities (2017 – $994 million after-tax income; 2016 – $465 million after-tax income). Excluding these items, adjusted net earnings from operations for 2018 were $3,263 million compared with adjusted net earnings of $1,403 million for 2017 (2016 – $669 million adjusted net loss).

The increase in net earnings and adjusted net earnings from operations for 2018 from 2017 was primarily due to:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- higher realized SCO prices in the Oil Sands Mining and Upgrading segment;
- higher realized risk management gains; and
- higher crude oil and NGLs netbacks in the International segments;

partially offset by:

- lower crude oil and NGLs netbacks in the North America Exploration and Production segment;
- higher depletion, depreciation and amortization in the Oil Sands Mining and Upgrading segment;
- lower natural gas netbacks in the North America Exploration and Production segment; and
- lower crude oil and NGLs sales volumes in the Exploration and Production segments.

Net earnings and adjusted net earnings from operations for 2018 as compared to net earnings and adjusted net earnings from operations for 2017 included the impact of a significant decline in crude oil pricing in November and December 2018 as a result of an oversupplied domestic market environment and a lack of takeaway capacity, resulting in increased storage levels and higher apportionment on the Enbridge Mainline system. The WCS heavy differential averaged US$39.36 per bbl for the fourth quarter of 2018 (third quarter of 2018 – US$22.17 per bbl). The SCO price averaged US$37.48 per bbl for the fourth quarter of 2018 (third quarter of 2018 – US$68.44 per bbl).

Following the Government of Alberta's announcement on December 2, 2018 of a mandatory curtailment of crude oil production, the WCS heavy differential index narrowed to US$12.38 per bbl for the first quarter of 2019 and the differential between SCO and WTI benchmark pricing narrowed to US$2.70 per bbl for the first quarter of 2019. Crude oil and natural gas pricing are discussed in detail in the "Business Environment" section of this MD&A.

The impacts of share-based compensation, risk management activities and fluctuations in foreign exchange rates also contributed to the movements in net earnings (loss) for 2018 from 2017. These items are discussed in detail in the relevant sections of this MD&A.

CASH FLOWS FROM OPERATING ACTIVITIES AND ADJUSTED FUNDS FLOW

Cash flows from operating activities for 2018 increased to $10,121 million from $7,262 million for 2017 (2016 – $3,452 million). The increase in cash flows from operating activities for 2018 from 2017 was primarily due to the factors noted above relating to the fluctuations in adjusted net earnings (loss) (except for the effect of depletion, depreciation and amortization), as well as due to the impact of changes in non-cash working capital.

Adjusted funds flow for 2018 increased to $9,088 million ($7.46 per common share) from $7,347 million for 2017 ($6.25 per common share) (2016 – $4,293 million; $3.90 per common share). The increase in adjusted funds flow for 2018 from 2017 was primarily due to the factors noted above relating to the fluctuations in cash flows from operating activities excluding the impact of the net change in non-cash working capital, abandonment and certain movements in other long-term assets.

PRODUCT PRICING

In the Company's Exploration and Production activities, the 2018 average sales price per bbl of crude oil and NGLs decreased 3% to average $46.92 per bbl from $48.57 per bbl in 2017 (2016 – $36.93 per bbl), and the 2018 average natural gas price decreased 5% to average $2.61 per Mcf from $2.76 per Mcf in 2017 (2016 – $2.32 per Mcf). In the Oil Sands Mining and Upgrading segment, the Company's 2018 average SCO sales price increased 7% to average $68.61 per bbl from $63.98 per bbl in 2017 (2016 – $58.59 per bbl). Crude oil and NGLs and natural gas pricing are discussed in detail in the "Business Environment" section of this MD&A.

PRODUCTION VOLUMES

Total production of crude oil and NGLs before royalties for 2018 increased 20% to average 820,778 bbl/d from 685,236 bbl/d in 2017 (2016 – 523,873 bbl/d). The increase in crude oil and NGLs production from 2017 was primarily due to the impact of Phase 3 production at Horizon and acquisitions completed in 2017, partially offset by the impact of proactive measures taken by the Company to voluntarily curtail crude oil production and reduce drilling in heavy oil.

Total natural gas production before royalties for 2018 decreased 7% to average 1,548 MMcf/d from 1,662 MMcf/d in 2017 (2016 – 1,691 MMcf/d). The decrease in natural gas production from 2017 primarily reflected the impact of shut-in volumes due to low natural gas prices, a failure on a natural gas transmission line in British Columbia (T-South) and a turnaround at the third-party Pine River processing facility beginning on September 15, 2018. Operations at the facility were partially reinstated on December 6, 2018. Subject to regulatory approval, the Company targets to take over operations at the facility in the first half of 2019.

Total crude oil and NGLs and natural gas production volumes before royalties for 2018 increased 12% to average 1,078,813 BOE/d from 962,264 BOE/d in 2017 (2016 – 805,782 BOE/d). Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production" section of this MD&A.

SUMMARY OF QUARTERLY FINANCIAL RESULTS

The following is a summary of the Company's quarterly financial results for the eight most recently completed quarters:

($ millions, except per common share amounts)

2018	**Total**	**Dec 31**	**Sep 30**	**Jun 30**	**Mar 31**
Product sales	**$ 22,282**	**$ 3,831**	**$ 6,327**	**$ 6,389**	**$ 5,735**
Crude oil and NGLs	**$ 20,668**	**$ 3,327**	**$ 5,967**	**$ 6,071**	**$ 5,303**
Natural gas	**$ 1,614**	**$ 504**	**$ 360**	**$ 318**	**$ 432**
Net earnings (loss)	**$ 2,591**	**$ (776)**	**$ 1,802**	**$ 982**	**$ 583**
Net earnings (loss) per common share					
– basic	**$ 2.13**	**$ (0.64)**	**$ 1.48**	**$ 0.80**	**$ 0.48**
– diluted	**$ 2.12**	**$ (0.64)**	**$ 1.47**	**$ 0.80**	**$ 0.47**

($ millions, except per common share amounts)

2017	Total	Dec 31	Sep 30	Jun 30	Mar 31
Product sales	$ 18,360	$ 5,516	$ 4,725	$ 4,127	$ 3,992
Crude oil and NGLs	$ 16,522	$ 5,098	$ 4,320	$ 3,645	$ 3,459
Natural gas	$ 1,838	$ 418	$ 405	$ 482	$ 533
Net earnings (loss)	$ 2,397	$ 396	$ 684	$ 1,072	$ 245
Net earnings (loss) per common share					
– basic	$ 2.04	$ 0.32	$ 0.56	$ 0.93	$ 0.22
– diluted	$ 2.03	$ 0.32	$ 0.56	$ 0.93	$ 0.22

Volatility in the quarterly net earnings (loss) over the eight most recently completed quarters was primarily due to:

- **Crude oil pricing** – Fluctuating global supply/demand including crude oil production levels from the Organization of the Petroleum Exporting Countries ("OPEC") and its impact on world supply, the impact of geopolitical uncertainties on worldwide benchmark pricing, the impact of shale oil production in North America, the impact of the Western Canadian Select ("WCS") Heavy Differential from the West Texas Intermediate reference location at Cushing, Oklahoma ("WTI") in North America including the impact of a shortage of takeaway capacity out of the Western Canadian Sedimentary Basin (the "Basin") and the impact of the differential between WTI and Dated Brent ("Brent") benchmark pricing in the North Sea and Offshore Africa.
- **Natural gas pricing** – The impact of fluctuations in both the demand for natural gas and inventory storage levels, third-party pipeline maintenance and outages and the impact of shale gas production in the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production due to the cyclic nature of the Company's Primrose thermal projects, production from Kirby South, the results from the Pelican Lake water and polymer flood projects, fluctuations in the Company's drilling program in North America, the impact and timing of acquisitions, including the acquisition of AOSP and other assets, production from Horizon Phase 3 as well as the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, voluntarily curtailed production due to low commodity prices in North America, and the impact of the drilling program in the International segments. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the International segments.
- **Natural gas sales volumes** – Fluctuations in production due to the Company's allocation of capital to higher return crude oil projects, natural decline rates, fluctuating capacity at a third-party processing facility, shut-in production due to third party pipeline restrictions and related pricing impacts, shut-in production due to low commodity prices, and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand and cost for services, fluctuations in product mix and production volumes, the impact of seasonal costs that are dependent on weather, the impact of increased carbon tax and energy costs, cost optimizations across all segments, the impact and timing of acquisitions, including the acquisition of AOSP and other assets, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, and maintenance activities in the International segments.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions and dispositions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, fluctuations in International sales volumes subject to higher depletion rates, fluctuations in depletion, depreciation and amortization expense in the North Sea due to the cessation of production at the Ninian North platform in the second quarter of 2017, and the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment.

- **Share-based compensation** – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model of the Company's share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- **Foreign exchange rates** – Fluctuations in the Canadian dollar relative to the US dollar, which impact the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses were also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Income tax expense** – Fluctuations in income tax expense due to statutory tax rate and other legislative changes substantively enacted in the various periods.
- **Gains on acquisition, disposition and revaluation of properties and gains/losses on investments** – Fluctuations due to the recognition of gains on the acquisition of AOSP and other assets, the acquisition, disposition and revaluation of properties in the various periods, fair value changes in the investments in PrairieSky and Inter Pipeline shares, and the equity loss (gain) on the Company's interest in the Redwater Partnership.

Business Environment

(Yearly average)		**2018**		2017		2016
WTI benchmark price (US$/bbl)	**$**	**64.78**	$	50.93	$	43.37
Dated Brent benchmark price (US$/bbl)	**$**	**71.12**	$	54.38	$	43.96
WCS heavy differential from WTI (US$/bbl)	**$**	**26.29**	$	11.97	$	13.91
SCO price (US$/bbl)	**$**	**58.62**	$	52.20	$	43.94
Condensate benchmark price (US$/bbl)	**$**	**60.98**	$	51.65	$	42.51
NYMEX benchmark price (US$/MMBtu)	**$**	**3.08**	$	3.11	$	2.45
AECO benchmark price (C$/GJ)	**$**	**1.45**	$	2.30	$	1.98
US/Canadian dollar average exchange rate (US$)	**$**	**0.7717**	$	0.7701	$	0.7548
US/Canadian dollar year end exchange rate (US$)	**$**	**0.7328**	$	0.7988	$	0.7448

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Brent indices. Canadian natural gas pricing is primarily based on Alberta AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company's realized prices are highly sensitive to fluctuations in foreign exchange rates. During 2018, product revenue continued to be impacted by the volatility in the Canadian dollar as the Canadian dollar sales price the Company received for its crude oil and natural gas sales is based on US dollar denominated benchmarks. The average value of the Canadian dollar in relation to the US dollar fluctuated throughout 2018, with a high of approximately US$0.81 in February 2018 and a low of approximately US$0.73 in December 2018.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$64.78 per bbl for 2018, an increase of 27% from US$50.93 per bbl for 2017 (2016 – US$43.37 per bbl).

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$71.12 per bbl for 2018, an increase of 31% from US$54.38 per bbl for 2017 (2016 – US$43.96 per bbl).

WTI and Brent pricing for 2018 increased from 2017 primarily due to declines in global crude oil inventories, together with larger than anticipated increases in global demand for crude oil.

The WCS heavy differential averaged US$26.29 per bbl for 2018, an increase of 120% from US$11.97 per bbl for 2017 (2016 – US$13.91 per bbl). The significant widening of the WCS heavy differential reflected a shortage of takeaway capacity out of the Basin, resulting in increased storage levels and higher apportionment on the Enbridge Mainline system. Following the Government of Alberta's announcement on December 2, 2018 of a mandatory curtailment of crude oil production, the WCS heavy differential index narrowed to US$12.38 per bbl for the first quarter of 2019 compared to US$39.36 per bbl during the fourth quarter of 2018.

The SCO price averaged US$58.62 per bbl for 2018, an increase of 12% from US$52.20 per bbl for 2017 (2016 – US$43.94 per bbl). The increase in SCO pricing for 2018 from 2017 primarily reflected increases in WTI benchmark pricing through the third quarter of 2018, partially offset by decreased pricing in the fourth quarter of 2018 due to a shortage of takeaway capacity out of the Basin, resulting in increased storage levels and higher apportionment on the Enbridge Mainline system. Following the Government of Alberta's announcement on December 2, 2018 of a mandatory curtailment of crude oil production, the differential between SCO and WTI benchmark pricing narrowed to US$2.70 per bbl for the first quarter of 2019 compared to US$21.35 per bbl during the fourth quarter of 2018.

Condensate pricing averaged US$60.98 per bbl for 2018, an increase of 18% from US$51.65 per bbl for 2017 (2016 – US$42.51 per bbl). The increase in condensate pricing for 2018 from 2017 primarily reflected increases in the underlying benchmark pricing.

NYMEX natural gas prices averaged US$3.08 per MMBtu for 2018, comparable with US$3.11 per MMBtu for 2017 (2016 – US$2.45 per MMBtu). AECO natural gas prices averaged $1.45 per GJ for 2018, a decrease of 37% from $2.30 per GJ for 2017 (2016 – $1.98 per GJ).

The decrease in AECO natural gas prices for 2018 compared with 2017 reflected third party pipeline constraints limiting flow of natural gas to export markets as well as increased natural gas production in the Basin.

Analysis of Changes in Product Sales

		Changes due to				**Changes due to**			
($ millions)	2016	Volumes	Prices	Other	2017	**Volumes**	**Prices**	**Other**	**2018**
North America									
Crude oil and NGLs	$ 5,933	$ 135	$ 1,755	$ (168)	$ 7,655	**$ (188)**	**$ (224)**	**$ 11**	**$ 7,254**
Natural gas	1,276	(20)	250	–	1,506	**(105)**	**(136)**	**(9)**	**1,256**
	7,209	115	2,005	(168)	9,161	**(293)**	**(360)**	**2**	**8,510**
North Sea									
Crude oil and NGLs	478	63	130	(5)	666	**(69)**	**155**	**1**	**753**
Natural gas	92	3	23	–	118	**(23)**	**45**	**–**	**140**
	570	66	153	(5)	784	**(92)**	**200**	**1**	**893**
Offshore Africa									
Crude oil and NGLs	532	(70)	103	14	579	**(102)**	**164**	**(13)**	**628**
Natural gas	71	(22)	4	–	53	**10**	**7**	**–**	**70**
	603	(92)	107	14	632	**(92)**	**171**	**(13)**	**698**
Subtotal									
Crude oil and NGLs	6,943	128	1,988	(159)	8,900	**(359)**	**95**	**(1)**	**8,635**
Natural gas	1,439	(39)	277	–	1,677	**(118)**	**(84)**	**(9)**	**1,466**
	8,382	89	2,265	(159)	10,577	**(477)**	**11**	**(10)**	**10,101**
Oil Sands Mining and Upgrading	2,657	3,827	561	27	7,072	**3,696**	**722**	**31**	**11,521**
Midstream	114	–	–	(12)	102	**–**	**–**	**–**	**102**
Intersegment eliminations and other (1)	849	–	–	(240)	609	**–**	**–**	**(51)**	**558**
Total	$ 12,002	$ 3,916	$ 2,826	$ (384)	$ 18,360	**$ 3,219**	**$ 733**	**$ (30)**	**$ 22,282**

(1) Eliminates internal transportation and electricity charges and includes production, processing and other purchasing and selling activities that are not included in the above segments.

Product sales increased 21% to $22,282 million for 2018 from $18,360 million for 2017 (2016 – $12,002 million). The increase was primarily due to higher SCO sales volumes and higher realized SCO sales prices in the Oil Sands Mining and Upgrading segment.

For 2018, 7% of the Company's crude oil and NGLs and natural gas product sales were generated outside of North America (2017 – 8%; 2016 – 10%). North Sea accounted for 4% of crude oil and NGLs and natural gas product sales for 2018 (2017 – 4%; 2016 – 5%), and Offshore Africa accounted for 3% of crude oil and NGLs and natural gas product sales for 2018 (2017 – 4%; 2016 – 5%).

Daily Production, Before Royalties

	2018	2017	2016
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**350,961**	359,449	350,958
North America – Oil Sands Mining and Upgrading (1)	**426,190**	282,026	123,265
North Sea	**23,965**	23,426	23,554
Offshore Africa	**19,662**	20,335	26,096
	820,778	685,236	523,873
Natural gas (MMcf/d)			
North America	**1,490**	1,601	1,622
North Sea	**32**	39	38
Offshore Africa	**26**	22	31
	1,548	1,662	1,691
Total barrels of oil equivalent (BOE/d)	**1,078,813**	962,264	805,782
Product mix			
Light and medium crude oil and NGLs	**13%**	14%	17%
Pelican Lake heavy crude oil	**6%**	6%	6%
Primary heavy crude oil	**8%**	10%	13%
Bitumen (thermal oil)	**10%**	12%	14%
Synthetic crude oil (1)	**39%**	29%	15%
Natural gas	**24%**	29%	35%
Percentage of gross revenue (1) (2) (excluding Midstream revenue)			
Crude oil and NGLs	**93%**	90%	85%
Natural gas	**7%**	10%	15%

(1) 2018 SCO production before royalties excludes 3,093 bbl/d of SCO consumed internally as diesel (2017 – 651 bbl/d, 2016 – 1,966 bbl/d).
(2) Net of blending costs and excluding risk management activities.

Daily Production, Net of Royalties

	2018	2017	2016
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**303,956**	312,297	311,059
North America – Oil Sands Mining and Upgrading	**405,731**	274,437	122,258
North Sea	**23,902**	23,382	23,497
Offshore Africa	**18,450**	19,124	24,995
	752,039	629,240	481,809
Natural gas (MMcf/d)			
North America	**1,432**	1,528	1,559
North Sea	**32**	39	38
Offshore Africa	**23**	20	30
	1,487	1,587	1,627
Total barrels of oil equivalent (BOE/d)	**999,857**	893,702	752,974

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely light and medium crude oil and NGLs, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), SCO and natural gas.

Total 2018 production averaged 1,078,813 BOE/d, a 12% increase from 962,264 BOE/d in 2017 (2016 – 805,782 BOE/d).

Total production of crude oil and NGLs for 2018 increased 20% to 820,778 bbl/d from 685,236 bbl/d for 2017 (2016 – 523,873 bbl/d). The increase in crude oil and NGLs production from 2017 was primarily due to the impact of Phase 3 production at Horizon and acquisitions completed in 2017, partially offset by the impact of proactive measures taken by the Company to voluntarily curtail crude oil production and reduce heavy oil drilling. Crude oil and NGLs production for 2018 was above the midpoint of the Company's previously issued guidance of 812,000 to 822,000 bbl/d.

Natural gas production accounted for 24% of the Company's total production in 2018 on a BOE basis. Natural gas production for 2018 decreased 7% to 1,548 MMcf/d from 1,662 MMcf/d for 2017 (2016 – 1,691 MMcf/d). The decrease in natural gas production from 2017 primarily reflected the impact of shut-in volumes due to low natural gas prices, natural field declines and reduced drilling activity, together with the impact of downtime and restricted capacity at the third-party Pine River processing facility. Subject to regulatory approval, the Company targets to take over operations at the facility in the first half of 2019. Natural gas production for 2018 was within the Company's previously issued guidance of 1,545 to 1,555 MMcf/d.

North America – Exploration and Production

North America crude oil and NGLs production for 2018 decreased 2% to average 350,961 bbl/d from 359,449 bbl/d for 2017 (2016 – 350,958 bbl/d). The decrease in production from 2017 primarily reflected the impact of proactive measures taken by the Company to voluntarily curtail crude oil production, together with reduced heavy oil drilling and natural field declines.

Operating performance at Pelican Lake continued to be strong following the acquisition completed in 2017, leading to average production of 63,082 bbl/d in 2018 compared with 51,743 bbl/d in 2017 (2016 – 47,637 bbl/d). The polymer flood on the acquired Pelican assets was restored to 62% of the field.

Overall thermal oil production for 2018 averaged 107,839 bbl/d compared with 120,140 bbl/d for 2017 (2016 – 111,046 bbl/d). Production volumes in 2018 primarily reflected the impact of proactive measures taken by the Company to voluntarily curtail crude oil production.

Natural gas production for 2018 decreased 7% to average 1,490 MMcf/d from 1,601 MMcf/d for 2017 (2016 – 1,622 MMcf/d). The decrease in natural gas production from 2017 primarily reflected the impact of shut-in volumes due to low natural gas prices, natural field declines and reduced drilling activity, together with the impact of downtime and restricted capacity at the third-party Pine River processing facility.

North America – Oil Sands Mining and Upgrading

SCO production for 2018 increased 51% to 426,190 bbl/d from 282,026 bbl/d for 2017 (2016 – 123,265 bbl/d). The increase in SCO production from 2017 primarily reflected high Phase 3 production reliability at Horizon and the acquisition of AOSP.

North Sea

North Sea crude oil production for 2018 increased 2% to 23,965 bbl/d from 23,426 bbl/d for 2017 (2016 – 23,554 bbl/d). The increase in production from 2017 primarily reflected the successful drilling program completed in 2018, partially offset by natural field declines.

Offshore Africa

Offshore Africa crude oil production for 2018 decreased 3% to 19,662 bbl/d from 20,335 bbl/d for 2017 (2016 – 26,096 bbl/d). Production volumes decreased from 2017 primarily due to natural field declines offsetting volumes from new wells drilled at Baobab in the latter half of 2018.

Corporate Production Guidance for 2019

The Company targets production levels in 2019 to average between 782,000 bbl/d and 861,000 bbl/d of crude oil and NGLs and between 1,485 MMcf/d and 1,545 MMcf/d of natural gas. Corporate crude oil and NGLs production guidance for 2019 reflects production curtailments as currently mandated by the Government of Alberta for the first quarter of 2019.

INTERNATIONAL CRUDE OIL INVENTORY VOLUMES

The Company recognizes revenue on its crude oil production when control of the product passes to the customer and delivery has taken place. Revenue has not been recognized in the International business segments on crude oil volumes that were stored in various storage facilities or FPSOs, as follows:

(bbl)	**2018**	2017	2016
North Sea	**71,832**	–	987,316
Offshore Africa	**404,475**	121,936	1,126,999
	476,307	121,936	2,114,315

Exploration and Production

OPERATING HIGHLIGHTS

		2018		2017		2016
Crude oil and NGLs ($/bbl) (1)						
Sales price (2)	**$**	**46.92**	$	48.57	$	36.93
Transportation		**3.08**		2.80		2.61
Realized sales price, net of transportation		**43.84**		45.77		34.32
Royalties		**5.08**		5.24		3.40
Production expense		**15.69**		14.89		14.10
Netback	**$**	**23.07**	$	25.64	$	16.82
Natural gas ($/Mcf) (1)						
Sales price (2)	**$**	**2.61**	$	2.76	$	2.32
Transportation		**0.47**		0.39		0.33
Realized sales price, net of transportation		**2.14**		2.37		1.99
Royalties		**0.08**		0.11		0.09
Production expense		**1.36**		1.27		1.18
Netback (3)	**$**	**0.70**	$	0.99	$	0.72
Barrels of oil equivalent ($/BOE) (1)						
Sales price (2)	**$**	**34.62**	$	35.54	$	27.58
Transportation		**2.96**		2.66		2.44
Realized sales price, net of transportation		**31.66**		32.88		25.14
Royalties		**3.27**		3.40		2.21
Production expense		**12.71**		11.95		11.18
Netback	**$**	**15.68**	$	17.53	$	11.75

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.
(3) Natural gas netbacks exclude netbacks derived from the sale of NGLs. Combining natural gas and NGLs, the netback for 2018 was $1.18/Mcfe (2017 – $1.31/Mcfe, 2016 – $0.89/Mcfe).

PRODUCT PRICES

		2018		2017		2016
Crude oil and NGLs ($/bbl) (1) (2)						
North America	**$**	**41.82**	$	45.85	$	34.31
North Sea	**$**	**87.41**	$	69.43	$	55.91
Offshore Africa	**$**	**90.95**	$	67.15	$	54.96
Company average	**$**	**46.92**	$	48.57	$	36.93
Natural gas ($/Mcf) (1) (2)						
North America	**$**	**2.33**	$	2.58	$	2.15
North Sea	**$**	**12.08**	$	8.24	$	6.62
Offshore Africa	**$**	**7.34**	$	6.57	$	6.13
Company average	**$**	**2.61**	$	2.76	$	2.32
Company average ($/BOE) (1) (2)	**$**	**34.62**	$	35.54	$	27.58

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.

Realized crude oil and NGLs prices decreased 3% to average $46.92 per bbl for 2018 from $48.57 per bbl for 2017 (2016 – $36.93 per bbl), primarily due to the significant widening of the WCS heavy differential in the fourth quarter of 2018, partially offset by higher WTI and Brent benchmark pricing.

The Company's realized natural gas price decreased 5% to average $2.61 per Mcf for 2018 from $2.76 per Mcf for 2017 (2016 – $2.32 per Mcf). The decrease in 2018 primarily reflected third party pipeline constraints limiting the flow of natural gas to the export market, together with increased natural gas production in the Basin.

North America – Product Prices

North America realized crude oil prices decreased 9% to average $41.82 per bbl for 2018 from $45.85 per bbl for 2017 (2016 – $34.31 per bbl), primarily due to the widening of the WCS heavy differential, which reflected a shortage of takeaway capacity out of the Basin, resulting in increased storage levels and higher apportionment on the Enbridge Mainline system.

North America realized natural gas prices decreased 10% to average $2.33 per Mcf for 2018 from $2.58 per Mcf for 2017 (2016 – $2.15 per Mcf). The decrease primarily reflected third party pipeline constraints limiting the flow of natural gas to the export market, together with increased natural gas production in the Basin.

The Company continues to focus on its crude oil marketing strategy including a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with refiners to add incremental heavy crude oil and bitumen (thermal oil) conversion capacity. During 2018, the Company contributed approximately 175,100 bbl/d of heavy crude oil blends to the WCS stream.

The Company has entered into a 20 year transportation agreement to ship 75,000 bbl/d of crude oil on the proposed Trans Mountain Pipeline Expansion from Edmonton, Alberta to Vancouver, British Columbia. The National Energy Board has provided their recommendation that construction of the pipeline should proceed and the related Federal Government consultations with Indigenous communities are ongoing. Subject to Cabinet's final approval, the project could be issued a revised Certificate of Public Convenience and Necessity this summer with construction re-starting as early as August 2019.

The Company has also entered into a 20 year transportation agreement to ship 175,000 bbl/d of crude oil on the proposed TransCanada Keystone XL Pipeline from Hardisty, Alberta to the US Gulf Coast. TransCanada is awaiting the completion of a new supplemental environmental review addressing issues raised through litigation in a Montana Federal Court Case. A decision is also expected in April 2019 on the Nebraska Public Service Commission's route approval. Pre-construction activities have started and TransCanada is working to maintain an expected in-service date in 2021.

Comparisons of the prices received in North America Exploration and Production by product type were as follows:

(Yearly average)		**2018**		2017		2016
Wellhead Price (1) (2)						
Light and medium crude oil and NGLs ($/bbl)	**$**	**52.87**	$	47.78	$	37.72
Pelican Lake heavy crude oil ($/bbl)	**$**	**43.30**	$	48.30	$	36.03
Primary heavy crude oil ($/bbl)	**$**	**38.98**	$	46.88	$	34.73
Bitumen (thermal oil) ($/bbl)	**$**	**33.66**	$	42.49	$	30.47
Natural gas ($/Mcf)	**$**	**2.33**	$	2.58	$	2.15

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.

North Sea – Product Prices

North Sea realized crude oil prices increased 26% to average $87.41 per bbl for 2018 from $69.43 per bbl for 2017 (2016 – $55.91 per bbl). Realized crude oil prices per bbl in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The increase in realized crude oil prices in 2018 reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa – Product Prices

Offshore Africa realized crude oil prices increased 35% to average $90.95 per bbl for 2018 from $67.15 per bbl for 2017 (2016 – $54.96 per bbl). Realized crude oil prices per bbl in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The increase in realized crude oil prices in 2018 reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES

	2018	2017	2016
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 5.36**	$ 5.69	$ 3.69
North Sea	**$ 0.22**	$ 0.13	$ 0.13
Offshore Africa	**$ 6.00**	$ 4.13	$ 2.31
Company average	**$ 5.08**	$ 5.24	$ 3.40
Natural gas ($/Mcf) (1)			
North America	**$ 0.07**	$ 0.11	$ 0.08
Offshore Africa	**$ 1.00**	$ 0.76	$ 0.28
Company average	**$ 0.08**	$ 0.11	$ 0.09
Company average ($/BOE) (1)	**$ 3.27**	$ 3.40	$ 2.21

(1) Amounts expressed on a per unit basis are based on sales volumes.

North America – Royalties

Government royalties on a significant portion of North America crude oil and NGLs production fall under the oil sands royalty regime and are calculated on a project by project basis as a percentage of gross revenue less operating, capital and abandonment costs incurred ("net profit").

North America crude oil and natural gas royalty rates for 2018 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalty rates also reflected fluctuations in the WCS Heavy Differential.

Crude oil and NGLs royalty rates averaged approximately 14% of product sales for 2018 compared with 13% of product sales for 2017 (2016 – 12%). The increase in royalty rates for 2018 from 2017 was primarily due to higher realized crude oil prices for the majority of 2018, offsetting the impact of lower realized crude oil prices in the fourth quarter of 2018.

Natural gas royalty rates averaged approximately 4% of product sales for 2018 compared with 5% of product sales for 2017 (2016 – 4%). The decrease in royalty rates for 2018 from 2017 was primarily due to lower realized natural gas prices.

Offshore Africa – Royalties

Under the terms of the various Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital expenditures and production expenses, the status of payouts, and the timing of liftings from each field.

Royalty rates as a percentage of product sales averaged approximately 7% for 2018 compared with 7% of product sales for 2017 (2016 – 4%). Royalty rates as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields.

PRODUCTION EXPENSE

	2018	2017	2016
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 13.48**	$ 12.71	$ 11.89
North Sea	**$ 39.89**	$ 36.60	$ 42.47
Offshore Africa	**$ 26.34**	$ 24.07	$ 18.48
Company average	**$ 15.69**	$ 14.89	$ 14.10
Natural gas ($/Mcf) (1)			
North America	**$ 1.25**	$ 1.19	$ 1.12
North Sea	**$ 5.29**	$ 3.37	$ 3.09
Offshore Africa	**$ 2.76**	$ 2.90	$ 1.79
Company average	**$ 1.36**	$ 1.27	$ 1.18
Company average ($/BOE) (1)	**$ 12.71**	$ 11.95	$ 11.18

(1) Amounts expressed on a per unit basis are based on sales volumes.

North America – Production Expense

North America crude oil and NGLs production expense for 2018 increased 6% to $13.48 per bbl from $12.71 per bbl for 2017 (2016 – $11.89 per bbl). The increase in crude oil and NGLs production expense for 2018 from 2017 reflected increased carbon tax and energy costs in 2018 together with increased costs associated with the Company's proactive measures to voluntarily curtail crude oil production, partially offset by the Company's continuous focus on cost control and achieving efficiencies across the entire asset base.

North America natural gas production expense for 2018 increased 5% to $1.25 per Mcf from $1.19 per Mcf for 2017 (2016 – $1.12 per Mcf). The increase in natural gas production expense for 2018 from 2017 primarily reflected the impact of lower volumes on a relatively fixed cost base due to low natural gas prices and a turnaround at the third-party Pine River processing facility. Production expense in 2018 also reflected additional costs associated with the shut-in of production due to low natural gas pricing during 2018, partially offset by the Company's continuous focus on cost control and achieving efficiencies across the entire asset base.

North Sea – Production Expense

North Sea crude oil production expense for 2018 increased 9% to $39.89 per bbl from $36.60 per bbl for 2017 (2016 – $42.47 per bbl). The increase in crude oil production expense for 2018 from 2017 primarily reflected higher carbon tax costs and the strengthening of the UK pound sterling compared to the Canadian dollar.

Offshore Africa – Production Expense

Offshore Africa crude oil production expense related to the Baobab and Espoir fields in Côte d'Ivoire for 2018 was $13.30 per bbl, compared to $12.41 per bbl for 2017. Total Offshore Africa crude oil production expense, including the Olowi field in Gabon, was $26.34 per bbl for 2018, an increase of 9% from $24.07 per bbl for 2017 (2016 – $18.48 per bbl). Total Offshore Africa crude oil production expense for 2018 primarily reflected the timing of liftings from various fields, including the Olowi field in Gabon, that have different cost structures, fluctuating production volumes on a relatively fixed cost base, and planned maintenance activities. Production expense was also impacted by movements in the Canadian dollar.

During 2018, the Gabonese Republic approved cessation of production from the Company's Olowi field, as well as the terms of termination of the Olowi Production Sharing Contract and the surrender of the permit area back to the Gabonese Republic, including associated asset retirement obligations of $69 million. The transaction resulted in a pre-tax gain on disposition of property of $20 million ($14 million after-tax). In January 2019, the Company completed FPSO demobilization and sail away activities.

DEPLETION, DEPRECIATION AND AMORTIZATION

($ millions, except per BOE amounts)	**2018**	2017	2016
North America	**$ 3,132**	$ 3,243	$ 3,465
North Sea	**257**	509	458
Offshore Africa	**201**	205	262
Expense	**$ 3,590**	$ 3,957	$ 4,185
$/BOE (1)	**$ 15.12**	$ 15.82	$ 16.79

(1) Amounts expressed on a per unit basis are based on sales volumes.

Depletion, depreciation and amortization in 2018 decreased 4% to $15.12 per BOE from $15.82 per BOE for 2017 (2016 – $16.79 per BOE). The decrease in depletion, depreciation and amortization expense per BOE for 2018 from 2017 was primarily due to the impact of additional depletion, depreciation and amortization expense in 2017 related to the abandonment of the Ninian North platform in the North Sea.

ASSET RETIREMENT OBLIGATION ACCRETION

($ millions, except per BOE amounts)	**2018**	2017	2016
North America	**$ 87**	$ 80	$ 66
North Sea	**29**	27	35
Offshore Africa	**9**	9	12
Expense	**$ 125**	$ 116	$ 113
$/BOE (1)	**$ 0.53**	$ 0.46	$ 0.45

(1) Amounts expressed on a per unit basis are based on sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

Asset retirement obligation accretion expense per BOE for 2018 increased 15% to $0.53 per BOE from $0.46 per BOE for 2017 (2016 – $0.45 per BOE).

Oil Sands Mining and Upgrading

OPERATING HIGHLIGHTS

The Company continues to focus on safe, reliable and efficient operations and leveraging its expertise in capturing synergies following the acquisition completed in 2017. Production averaged 426,190 bbl/d during 2018, reflecting strong, reliable operations at Horizon, together with incremental reliability at AOSP. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability of operations, adjusted cash production costs averaged $21.05 per bbl for 2018.

PRODUCT PRICES, ROYALTIES AND TRANSPORTATION

($/bbl) (1)		**2018**		2017		2016
SCO realized sales price (2)	**$**	**68.61**	$	63.98	$	58.59
Bitumen value for royalty purposes (3)	**$**	**40.02**	$	41.05	$	27.57
Bitumen royalties (4)	**$**	**3.09**	$	1.64	$	0.54
Transportation	**$**	**1.61**	$	1.54	$	1.77

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending and feedstock costs.
(3) Calculated as the annual average of the bitumen valuation methodology price.
(4) Calculated based on bitumen royalties expensed during the year; divided by the corresponding SCO sales volumes.

The realized SCO sales price for the Oil Sands Mining and Upgrading segment averaged $68.61 per bbl for 2018, an increase of 7% compared with $63.98 per bbl for 2017 (2016 – $58.59 per bbl). The increase in SCO pricing for 2018 compared to 2017 primarily reflected WTI benchmark pricing.

CASH PRODUCTION COSTS

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 22 to the Company's audited consolidated financial statements.

($ millions)		**2018**		2017		2016
Cash production costs	**$**	**3,367**	$	2,600	$	1,292
Less: costs incurred during turnaround periods		**(109)**		(216)		(151)
Adjusted cash production costs	**$**	**3,258**	$	2,384	$	1,141

Adjusted cash production costs, excluding natural gas costs	**$**	**3,156**	$	2,239	$	1,057
Natural gas costs		**102**		145		84
Adjusted cash production costs	**$**	**3,258**	$	2,384	$	1,141

($/bbl) (1)		**2018**		2017		2016
Adjusted cash production costs, excluding natural gas costs	**$**	**20.39**	$	21.98	$	23.36
Natural gas costs		**0.66**		1.42		1.84
Adjusted cash production costs	**$**	**21.05**	$	23.40	$	25.20
Sales (bbl/d)		**424,112**		279,084		123,652

(1) Amounts expressed on a per unit basis are based on sales volumes.

Adjusted cash production costs for 2018 decreased 10% to $21.05 per bbl from $23.40 per bbl for 2017 (2016 – $25.20 per bbl). The decrease in adjusted cash production costs per barrel for 2018 from 2017 primarily reflected the Company's high utilization rates and reliability and the capture of cost synergies between the operations, as well as additional capacity from Phase 3 production at Horizon and the acquisition of AOSP.

DEPLETION, DEPRECIATION AND AMORTIZATION

($ millions, except per bbl amounts)		**2018**		2017		2016
Depletion, depreciation and amortization	**$**	**1,557**	$	1,220	$	662
Less: depreciation incurred during turnaround periods		**(56)**		(213)		(99)
Adjusted depletion, depreciation and amortization	**$**	**1,501**	$	1,007	$	563
$/bbl (1)	**$**	**9.70**	$	9.89	$	12.43

(1) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.

Adjusted depletion, depreciation and amortization expense per barrel for 2018 decreased 2% to $9.70 per bbl from $9.89 per bbl for 2017 (2016 – $12.43 per bbl), primarily due to the impact of AOSP, which has a lower depletion rate.

ASSET RETIREMENT OBLIGATION ACCRETION

($ millions, except per bbl amounts)		**2018**		2017		2016
Expense	**$**	**61**	$	48	$	29
$/bbl (1)	**$**	**0.40**	$	0.47	$	0.64

(1) Amounts expressed on a per unit basis are based on sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

Asset retirement obligation accretion expense per barrel for 2018 decreased 15% to $0.40 per bbl from $0.47 per bbl for 2017 (2016 – $0.64 per bbl), reflecting higher sales volumes.

Midstream

($ millions)		**2018**		2017		2016
Revenue	**$**	**102**	$	102	$	114
Less:						
Production expense		**21**		16		25
Depreciation		**14**		9		11
Equity loss (gain) from Redwater Partnership		**5**		(31)		(7)
Gain on disposition and revaluation of properties		**–**		(114)		(218)
Segment earnings before taxes	**$**	**62**	$	222	$	303

The Company's Midstream assets consist of two crude oil pipeline systems, a 50% working interest in an 84-megawatt cogeneration plant at Primrose and the Company's 50% interest in the Redwater Partnership. Approximately 46% of the Company's heavy crude oil production is transported to international mainline liquid pipelines via the 100% owned and operated ECHO and Pelican Lake pipelines. The Midstream pipeline asset ownership allows the Company to control transportation costs, earn third party revenue, and manage the marketing of heavy crudes.

During 2017, the Company recorded a pre-tax revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in a pipeline system. During 2016, the Company disposed of its interest in the Cold Lake Pipeline, including $321 million of property, plant and equipment, for total net consideration of $539 million, resulting in a pre and after-tax gain of $218 million. Total net consideration was comprised of $349 million in cash, together with $190 million of non-cash share consideration of approximately 6.4 million common shares of Inter Pipeline with a value of $29.57 per common share, determined as of the closing date.

Redwater Partnership has entered into agreements to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement.

The facility capital cost ("FCC") budget for the Project is currently estimated to be $9,700 million. The Project is currently in the commissioning phase, with completion targeted for the second quarter of 2019. During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to maintain the agreed debt to equity ratio of 80/20. To December 31, 2018, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $152 million, for a Company total of $591 million. Any additional subordinated debt financing is not expected to be significant.

Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service toll, currently consisting of interest and fees, with principal repayments beginning in 2020. The Company is unconditionally obligated to pay this portion of the cost of service toll over the 30 year tolling period. As at December 31, 2018, the Company had recognized $62 million in prepaid service tolls.

During 2017, Redwater Partnership issued $750 million of 2.80% series J senior secured bonds due June 2027 and $750 million of 3.65% series K senior secured bonds due June 2035.

During 2016, Redwater Partnership issued $550 million of 4.25% series F senior secured bonds due June 2029, $500 million of 4.75% series G senior secured bonds due June 2037, $500 million of 4.15% series H senior secured bonds due June 2033, and $500 million of 4.35% series I senior secured bonds due January 2039.

As at December 31, 2018, Redwater Partnership had borrowings of $2,333 million under its secured $3,500 million syndicated credit facility. During 2018, Redwater Partnership extended $2,000 million of the $3,500 million revolving syndicated credit facility to June 2021. The remaining $1,500 million was extended on a fully drawn non-revolving basis maturing February 2020.

Corporate and Other

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	**2018**	2017	2016
Expense	**$ 325**	$ 319	$ 345
$/BOE (1)	**$ 0.83**	$ 0.91	$ 1.17

(1) Amounts expressed on a per unit basis are based on sales volumes.

Administration expense per BOE for 2018 decreased 9% to $0.83 per BOE from $0.91 per BOE for 2017 (2016 – $1.17 per BOE). Administration expense per BOE decreased for 2018 from 2017 primarily due to higher sales volumes.

SHARE-BASED COMPENSATION

($ millions)	**2018**	2017	2016
(Recovery) expense	**$ (146)**	$ 134	$ 355

The Company's Stock Option Plan provides current employees with the right to receive common shares or a cash payment in exchange for stock options surrendered.

The Company recorded an $146 million share-based compensation recovery for the year ended December 31, 2018, primarily as a result of remeasurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period and changes in the Company's share price. Included within the share-based compensation recovery for 2018 was an expense of $8 million related to performance share units granted to certain executive employees (2017 – $5 million; 2016 – $nil). For 2018, the Company recovered $19 million of share-based compensation costs from the Oil Sands Mining and Upgrading segment (2017 – $14 million costs charged, 2016 – $67 million costs charged).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)	**2018**	2017	2016
Expense, gross	**$ 808**	$ 713	$ 616
Less: capitalized interest	**69**	82	233
Expense, net	**$ 739**	$ 631	$ 383
$/BOE (1)	**$ 1.88**	$ 1.79	$ 1.30
Average effective interest rate	**3.9%**	3.8%	3.9%

(1) Amounts expressed on a per unit basis are based on sales volumes.

Gross interest and other financing expense for 2018 increased from 2017 primarily due to the impact of higher average debt levels as a result of acquisitions completed in 2017 and higher interest rates in 2018. Capitalized interest of $69 million for 2018 was primarily related to Kirby North and residual project activities at Horizon.

Net interest and other financing expense for 2018 increased 5% to $1.88 per BOE from $1.79 per BOE for 2017 (2016 – $1.30 per BOE). The increase for 2018 from 2017 was primarily due to higher average debt levels as a result of acquisitions completed in 2017 and lower capitalized interest related to the completion of Horizon Phase 3.

The Company's average effective interest rate of 3.9% for 2018 was consistent with 2017 and 2016.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, interest rate and foreign currency exposures. These derivative financial instruments are not intended for trading or speculative purposes.

($ millions)	**2018**	2017	2016
Crude oil and NGLs financial instruments	**$ (27)**	$ (32)	$ –
Natural gas financial instruments	**5**	(7)	–
Foreign currency contracts	**(77)**	37	8
Realized (gain) loss	**$ (99)**	$ (2)	$ 8
Crude oil and NGLs financial instruments	**$ 16**	$ –	$ –
Natural gas financial instruments	**(4)**	(6)	6
Foreign currency contracts	**(47)**	43	19
Unrealized (gain) loss	**$ (35)**	$ 37	$ 25
Net (gain) loss	**$ (134)**	$ 35	$ 33

During 2018, net realized risk management gains were related to the settlement of foreign currency contracts and crude oil and NGLs financial instruments. The Company recorded a net unrealized gain of $35 million ($36 million after-tax) on its risk management activities for 2018 (2017 – $37 million unrealized loss, $33 million after-tax; 2016 – $25 million unrealized loss, $21 million after-tax).

Complete details related to outstanding derivative financial instruments at December 31, 2018 are disclosed in note 19 to the Company's audited consolidated financial statements.

FOREIGN EXCHANGE

($ millions)	**2018**	2017	2016
Net realized loss	**$ 121**	$ 34	$ 38
Net unrealized loss (gain)	**706**	(821)	(93)
Net loss (gain) [1]	**$ 827**	$ (787)	$ (55)

(1) Amounts are reported net of the hedging effect of cross currency swaps.

The net realized foreign exchange loss for 2018 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the repayment of US$600 million of 1.75% notes and US$400 million of 5.90% notes. The net unrealized foreign exchange loss for 2018 was primarily related to the impact of the weakening Canadian dollar with respect to outstanding US dollar debt, partially offset by the reversal of the net unrealized foreign exchange loss on the repayment of US$600 million of 1.75% notes and US$400 million of 5.90% notes. The net unrealized loss (gain) for each of the periods presented included the impact of cross currency swaps (2018 – unrealized gain of $118 million, 2017 – unrealized loss of $280 million, 2016 – unrealized loss of $295 million). The US/Canadian dollar exchange rate at December 31, 2018 was US$0.7328 (December 31, 2017 – US$0.7988, December 31, 2016 – US$0.7448).

INCOME TAXES

($ millions, except income tax rates)		**2018**		2017		2016
North America [1]	**$**	**312**	$	(145)	$	(377)
North Sea		**28**		57		(74)
Offshore Africa		**54**		45		22
PRT – North Sea		**(29)**		(132)		(198)
Other taxes		**9**		11		9
Current income tax expense (recovery)		**374**		(164)		(618)
Deferred corporate income tax expense (recovery)		**540**		586		(106)
Deferred PRT expense (recovery) – North Sea		**17**		54		(135)
Deferred income tax expense (recovery)		**557**		640		(241)
		931		476		(859)
Income tax rate and other legislative changes		**–**		(10)		221
	$	**931**	$	466	$	(638)
Effective income tax rate on adjusted net earnings (loss) from operations [2]		**21%**		27%		45%

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.
(2) Excludes the impact of current and deferred PRT expense and other current income tax expense.

The effective income tax rate for 2018 and the comparable years included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income (loss) and tax rates in the countries in which the Company operates, in relation to net earnings (loss). In addition, the effective income tax rate for 2016 also reflected the successful resolution of certain prior year tax matters.

The current corporate income tax and PRT recoveries in the North Sea in 2018 and the comparable years included the impact of abandonment expenditures.

During 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by $10 million.

During 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of $107 million. In addition, the UK government also enacted legislation to reduce the PRT rate from 35% to 0% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to 2015 and prior taxation years for PRT purposes are still recoverable at a PRT rate of 50%. As a result of these tax changes, the Company's deferred PRT liability was reduced by $228 million and the deferred corporate income tax liability was increased by $114 million.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's reported results of operations, financial position or liquidity.

For 2019, current income tax expense is targeted to range from $300 million to $400 million in Canada and $55 million to $85 million in the North Sea and Offshore Africa.

During 2018, the Company filed Scientific Research and Experimental Development claims of approximately $265 million (2017 – $345 million; 2016 – $549 million) relating to qualifying research and development expenditures for Canadian income tax purposes.

Net Capital Expenditures [1]

($ millions)		2018		2017		2016
Exploration and Evaluation						
Net expenditures (proceeds) [2] [3] [4]	**$**	**48**	$	149	$	(6)
Property, Plant and Equipment						
Net property acquisitions [2] [3] [4]		**98**		1,219		159
Well drilling, completion and equipping		**1,446**		1,001		712
Production and related facilities		**1,262**		860		369
Capitalized interest and other [5]		**106**		91		91
Net expenditures		**2,912**		3,171		1,331
Total Exploration and Production		**2,960**		3,320		1,325
Oil Sands Mining and Upgrading						
Project costs [6]		**438**		821		1,920
Sustaining capital		**665**		561		379
Turnaround costs		**112**		155		135
Acquisitions of Exploration and Evaluation assets [2] [4] [7]		**218**		219		–
Net property acquisitions [2] [4]		**–**		11,604		–
Capitalized interest and other [5]		**14**		76		284
Total Oil Sands Mining and Upgrading		**1,447**		13,436		2,718
Midstream [8]		**13**		80		(533)
Abandonments [9]		**290**		274		267
Head office		**21**		19		17
Total net capital expenditures	**$**	**4,731**	$	17,129	$	3,794
By segment						
North America [2] [3] [4]	**$**	**2,671**	$	3,056	$	1,048
North Sea [3]		**131**		160		126
Offshore Africa [3]		**158**		104		151
Oil Sands Mining and Upgrading [4] [7]		**1,447**		13,436		2,718
Midstream [8]		**13**		80		(533)
Abandonments [9]		**290**		274		267
Head office		**21**		19		17
Total	**$**	**4,731**	$	17,129	$	3,794

(1) Net capital expenditures exclude fair value and revaluation adjustments, and include non-cash transfers of property, plant and equipment to inventory due to change in use.
(2) Includes business combinations.
(3) Includes proceeds from the acquisition and disposition of properties.
(4) During 2017, total purchase consideration for the acquisition of AOSP of $12,157 million includes $26 million of exploration and evaluation assets and $308 million of property, plant and equipment within the North America segment, and $219 million of exploration and evaluation assets and $11,604 million of property, plant and equipment within the Oil Sands Mining and Upgrading segment.
(5) Capitalized interest and other includes expenditures related to land acquisition and retention, seismic, and other adjustments.
(6) Includes Horizon Phase 2/3 construction costs.
(7) In the fourth quarter of 2018, following integration of the Joslyn oil sands project into the Horizon mine plan and determination of proved crude oil reserves, the exploration and evaluation assets were transferred to property, plant, and equipment.
(8) Includes non-cash share consideration of $190 million received from Inter Pipeline on the disposition of Midstream assets in 2016.
(9) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

NET CAPITAL EXPENDITURES, AS RECONCILED TO CASH FLOWS USED IN INVESTING ACTIVITIES

($ millions)	2018	2017	2016
Cash flows used in investing activities	**$ 4,814**	$ 13,102	$ 3,811
Net change in non-cash working capital (1) (2)	**(345)**	22	5
Investment in other long-term assets	**(28)**	(87)	(99)
Share consideration in business acquisitions (dispositions)	**–**	3,818	(190)
Abandonment expenditures (3)	**290**	274	267
Net capital expenditures	**$ 4,731**	$ 17,129	$ 3,794

(1) Includes net working capital of $291 million related to the acquisition of AOSP in 2017.
(2) Includes property, plant and equipment of $80 million transferred to inventory in 2016.
(3) The Company excludes abandonment expenditures from "Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities" in the "Financial and Operational Highlights" section of this MD&A.

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core areas. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By owning associated infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production expenses.

Net capital expenditures for 2018 were $4,731 million compared with $17,129 million for 2017 (2016 – $3,794 million). Net capital expenditures for 2017 included $12,157 million related to the acquisition of AOSP and other assets and $921 million related to the acquisition of assets in the Greater Pelican Lake region and other miscellaneous assets. Net capital expenditures for 2018 included:

- $105 million (US$79 million) of proceeds for the disposal of a 30% interest in the exploration right in South Africa, comprised of exploration and evaluation assets of $89 million, including a recovery of $14 million of past incurred costs in the Offshore Africa segment;
- $218 million of consideration for the acquisition of the Joslyn oil sands project in the Oil Sands Mining and Upgrading segment (comprising $100 million cash on closing with the remaining balance paid equally over the next five years);
- $22 million of cash consideration for the acquisition of Laricina Energy Ltd. in the North America Exploration and Production segment (net of $24 million of cash acquired); and
- $73 million of cash proceeds for the acquisition of the remaining interest at the Ninian field in the North Sea.

2019 CAPITAL BUDGET

On December 5, 2018, the Company announced its 2019 Capital Budget. The 2019 budget targets a base capital program of $3,700 million, including $3,100 million to maintain current production levels and approximately $600 million directed toward long-term growth projects. The Company maintains capital flexibility in its 2019 budget. Should market access conditions improve, the Company has the capability to adjust 2019 capital spending. Capital expenditures in 2019 are discussed in further detail in the "Outlook" section of this MD&A.

DRILLING ACTIVITY

(number of wells)	2018	2017	2016
Net successful natural gas wells	**18**	21	9
Net successful crude oil wells (1)	**483**	495	174
Dry wells	**9**	7	7
Stratigraphic test / service wells	**615**	289	268
Total	**1,125**	812	458
Success rate (excluding stratigraphic test / service wells)	**98%**	99%	96%

(1) Includes bitumen wells.

North America

During 2018, the Company targeted 18 net natural gas wells, 6 in Northeast British Columbia and 12 in Northwest Alberta. The Company also targeted 486 net crude oil wells. The majority of these net wells were concentrated in the Company's Northern Plains region where 240 primary heavy crude oil wells, 125 bitumen (thermal oil) wells, 22 Pelican Lake heavy crude oil wells and 7 light crude oil wells were drilled. Another 92 wells targeting light crude oil were drilled outside the Northern Plains region.

The Company's strategic and proactive decisions and its ability to utilize capital flexibility based on its large, balanced and diverse asset base has been reflected in the North America drilling program. During 2018, the Company reallocated capital spending from primary heavy crude oil to light crude oil, with an increase of 32 net wells in light crude oil and a corresponding decrease of 137 net wells in primary heavy crude oil.

North Sea

During 2018, the Company completed four gross production wells and one gross injection well (4.9 on a net basis), successfully completing the 2018 drilling program in the North Sea.

Offshore Africa

During 2018, the Company completed three gross production wells (1.7 on a net basis) at Baobab. The Company is targeting one gross production well and two gross injection wells at Baobab in 2019.

The Company has retained a 20% working interest in Block 11B/12B, off the southern coast of South Africa. In late December, the operator of the exploration right commenced the drilling of an exploratory well. Subsequent to December 31, 2018, the operator announced that drilling results indicate the presence of natural gas condensate. The Company expects the cost of the current exploration well to be fully carried pursuant to two separate farm-out agreements that were completed in 2018.

Liquidity and Capital Resources

($ millions, except ratios)	2018	2017	2016
Working capital (1)	**$ (601)**	$ 513	$ 1,056
Long-term debt (2) (3)	**$ 20,623**	$ 22,458	$ 16,805
Less: cash and cash equivalents	**101**	137	17
Long-term debt, net	**$ 20,522**	$ 22,321	$ 16,788
Share capital	**$ 9,323**	$ 9,109	$ 4,671
Retained earnings	**22,529**	22,612	21,526
Accumulated other comprehensive income (loss)	**122**	(68)	70
Shareholders' equity	**$ 31,974**	$ 31,653	$ 26,267
Debt to book capitalization (3) (4)	**39%**	41%	39%
Debt to market capitalization (3) (5)	**34%**	29%	26%
After-tax return on average common shareholders' equity (6)	**8%**	8%	(1%)
After-tax return on average capital employed (3) (7)	**6%**	6%	0%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.
(2) Includes the current portion of long-term debt (2018 – $1,141 million, 2017 – $1,877 million, 2016 – $1,812 million).
(3) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts and premiums and transaction costs.
(4) Calculated as net current and long-term debt; divided by the book value of common shareholders' equity plus net current and long-term debt.
(5) Calculated as net current and long-term debt; divided by the market value of common shareholders' equity plus net current and long-term debt.
(6) Calculated as net earnings (loss) for the year; as a percentage of average common shareholders' equity for the year.
(7) Calculated as net earnings (loss) plus after-tax interest and other financing expense for the year; as a percentage of average capital employed for the year.

As at December 31, 2018, the Company's capital resources consisted primarily of cash flows from operating activities, available bank credit facilities and access to debt capital markets. Cash flows from operating activities and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Risks and Uncertainties" section of this MD&A. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings as determined by independent rating agencies, and the conditions of the market. The Company continues to believe that its internally generated cash flows from operating activities supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs and multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long-term and support its growth strategy.

On an ongoing basis the Company continues to focus on its balance sheet strength and available liquidity by:

- Monitoring cash flows from operating activities, which is the primary source of funds;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Utilizing cash flows from operating activities to facilitate net repayment of bank credit facilities and US dollar debt securities of $3,312 million for 2018, excluding the impact of foreign exchange on debt balances, including:
  - repayment and cancellation of the $125 million non-revolving credit facility;
  - repayment and cancellation of $1,200 million of the $3,000 million non-revolving credit facility; and
  - repayment of US$600 million of 1.75% notes and US$400 million of 5.90% notes.
- Additionally, the Company utilized available liquidity to settle the deferred payment to Marathon for $481 million, resulting in total net repayments of debt of $2,831 million.
- Reviewing the Company's borrowing capacity:
  - During 2018, the Company extended the $2,425 million revolving syndicated credit facility originally due June 2020 to June 2022. During 2017, the Company extended $2,095 million of the other $2,425 million revolving syndicated credit facility originally due June 2019 to June 2021. The remaining $330 million outstanding under this facility continues under the previous terms and matures in June 2019. Each of the $2,425 million revolving facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal is repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.
  - During 2018, the Company extended the $2,200 million non-revolving credit facility originally due October 2019 to October 2020. Borrowings under the $2,200 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2018, the $2,200 million facility was fully drawn.
  - During 2018, the Company extended the $750 million non-revolving credit facility originally due in February 2019 to February 2021. Borrowings under the $750 million non-revolving term credit facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2018, the $750 million facility was fully drawn.
  - Borrowings under the $1,800 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. This facility matures in May 2020 and is subject to annual amortization of 5% of the original balance. As at December 31, 2018, the $1,800 million facility was fully drawn.
  - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US$2,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.
  - During 2017, the Company issued $900 million of 2.05% medium-term notes due June 2020, $600 million of 3.42% medium-term notes due December 2026 and $300 million of 4.85% medium-term notes due May 2047. Proceeds from the securities were used to finance the acquisition of AOSP and other assets. In July 2017, the Company filed a new base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
  - During 2017, the Company repaid US$1,100 million of 5.70% notes, and issued US$1,000 million of 2.95% notes due January 2023, US$1,250 million of 3.85% notes due June 2027 and US$750 million of 4.95% notes due June 2047. Proceeds from the debt securities were used to finance the acquisition of AOSP and other assets. In July 2017, the Company filed a new base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages. The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at December 31, 2018, the Company was in compliance with this covenant; and
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default.

As at December 31, 2018, the Company had in place revolving bank credit facilities of $4,976 million of which $4,723 million was available. Additionally, the Company had in place fully drawn term credit facilities of $4,750 million. This excludes certain other dedicated credit facilities supporting letters of credit.

As at December 31, 2018, the Company had total US dollar denominated debt with a carrying amount of $14,611 million (US$10,708 million), before transaction costs and original issue discounts. This included $5,604 million (US$4,108 million) hedged by way of cross currency swaps (US$1,050 million) and foreign currency forwards (US$3,058 million). The fixed repayment amount of these hedging instruments is $5,256 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $348 million to $14,263 million as at December 31, 2018.

Net long-term debt was $20,522 million at December 31, 2018, resulting in a debt to book capitalization ratio of 39% (December 31, 2017 – 41%, December 31, 2016 - 39%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flows from operating activities is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt at December 31, 2018 are discussed in note 11 to the Company's audited consolidated financial statements.

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. As at December 31, 2018, 28,000 bbl/d of currently forecasted crude oil volumes were hedged using WCS differential swaps for January to March 2019 and 8,000 bbl/d were hedged for January to September 2019. Additionally, 10,000 MMbtu/d of currently forecasted natural gas volumes were hedged using AECO basis swaps for January to March 2019, 30,000 GJ/d were hedged using AECO fixed price swaps for January to March 2019 and 10,000 GJ/d were hedged for April to October 2019. Subsequent to December 31, 2018, the Company has hedged an additional 105,000 GJ/d of currently forecasted natural gas volumes using AECO fixed price swaps for April to October 2019. Further details related to the Company's commodity derivative financial instruments outstanding at December 31, 2018 are discussed in note 19 of the Company's audited consolidated financial statements.

SHARE CAPITAL

As at December 31, 2018, there were 1,201,886,000 common shares outstanding (December 31, 2017 – 1,222,769,000 common shares) and 46,685,000 stock options outstanding. As at March 5, 2019, the Company had 1,199,849,000 common shares outstanding and 50,413,000 stock options outstanding.

On March 6, 2019, the Board of Directors approved an increase in the quarterly dividend to $0.375 per common share, beginning with the dividend payable on April 1, 2019. On February 28, 2018, the Board of Directors approved an increase in the quarterly dividend to $0.335 per common share, beginning with the dividend payable on April 1, 2018. On March 1, 2017, the Board of Directors approved an increase in the quarterly dividend to $0.275 per common share, beginning with the dividend payable on April 1, 2017. On November 2, 2016, the Board of Directors approved an increase in the quarterly dividend to $0.25 per common share (previous quarterly dividend rate of $0.23 per common share), beginning with the dividend payable on January 1, 2017. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On May 16, 2018, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 61,454,856 common shares, over a 12-month period commencing May 23, 2018 and ending May 22, 2019. The Company's Normal Course Issuer Bid announced in March 2017 expired on May 22, 2018.

During 2018, the Company purchased for cancellation 30,857,727 common shares at a weighted average price of $41.56 per common share for a total cost of $1,282 million. Retained earnings were reduced by $1,044 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2018, the Company purchased 4,340,000 common shares at a weighted average price of $35.86 per common share for a total cost of $156 million.

Commitments and Contingencies

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. The following table summarizes the Company's commitments as at December 31, 2018:

($ millions)	2019	2020	2021	2022	2023	Thereafter
Product transportation and pipeline	$ 692	$ 664	$ 620	$ 516	$ 381	$ 3,991
North West Redwater Partnership debt service toll (1)	$ 86	$ 126	$ 157	$ 158	$ 157	$ 2,858
Offshore equipment operating leases	$ 94	$ 73	$ 75	$ 8	$ –	$ –
Long-term debt (2)	$ 1,141	$ 5,996	$ 1,444	$ 1,003	$ 1,365	$ 9,793
Interest and other financing expense (3)	$ 836	$ 755	$ 610	$ 558	$ 500	$ 5,327
Office leases	$ 42	$ 42	$ 39	$ 31	$ 32	$ 89
Other	$ 85	$ 35	$ 32	$ 32	$ 31	$ 424

(1) Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service toll, currently consisting of interest and fees, with principal repayments beginning in 2020. Included in the service toll is $1,301 million of interest payable over the 30 year tolling period.
(2) Long-term debt represents principal repayments only and does not reflect original issue discounts and premiums or transaction costs.
(3) Interest and other financing payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2018.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of its various development projects. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

Reserves

For the years ended December 31, 2018, 2017 and 2016, the Company retained Independent Qualified Reserves Evaluators to evaluate and review all of the Company's proved and proved plus probable crude oil, NGLs and natural gas reserves. The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States FASB Topic 932 "Extractive Activities – Oil and Gas" in the Company's annual report on Form 40-F filed with the SEC and in the "Supplementary Oil and Gas Information" section of the Company's Annual Report.

The following tables summarize the company gross proved and proved plus probable reserves using forecast prices and costs as at December 31, 2018, prepared in accordance with NI 51-101 reserves disclosures:

Proved Reserves	**Light and Medium Crude Oil** (MMbbl)	**Primary Heavy Crude Oil** (MMbbl)	**Pelican Lake Heavy Crude Oil** (MMbbl)	**Bitumen (Thermal Oil)** (MMbbl)	**Synthetic Crude Oil** (MMbbl)	**Natural Gas** (Bcf)	**Natural Gas Liquids** (MMbbl)	**Barrels of Oil Equivalent** (MMBOE)
December 31, 2017	374	198	327	1,350	5,264	6,771	229	8,871
Discoveries	–	–	–	–	–	–	–	–
Extensions	12	14	–	171	808	122	9	1,034
Infill Drilling	18	6	–	4	–	470	38	144
Improved Recovery	–	–	1	2	–	3	–	4
Acquisitions	11	2	–	–	–	82	4	30
Dispositions	–	(5)	–	–	–	(3)	–	(5)
Economic Factors	5	1	1	–	–	(305)	(4)	(48)
Technical Revisions	14	(2)	(1)	52	175	77	6	257
Production	(35)	(32)	(23)	(39)	(156)	(565)	(15)	(394)
December 31, 2018	**399**	**182**	**305**	**1,540**	**6,091**	**6,652**	**267**	**9,893**

Proved Plus Probable Reserves	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	544	272	469	2,580	6,063	9,619	335	11,866
Discoveries	–	–	–	–	–	–	–	–
Extensions	16	21	–	230	879	215	14	1,196
Infill Drilling	24	8	–	5	–	861	60	241
Improved Recovery	1	–	3	4	–	4	–	8
Acquisitions	17	3	–	403	–	104	5	445
Dispositions	–	(6)	–	–	–	(5)	–	(7)
Economic Factors	(1)	1	1	–	–	(409)	(5)	(72)
Technical Revisions	9	(15)	(5)	(124)	246	(90)	3	99
Production	(35)	(32)	(23)	(39)	(156)	(565)	(15)	(394)
December 31, 2018	**575**	**252**	**445**	**3,059**	**7,032**	**9,734**	**397**	**13,382**

At December 31, 2018, the company gross proved crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 8,784 MMbbl, and company gross proved plus probable crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 11,760 MMbbl. Proved reserves additions and revisions replaced 447% of 2018 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 1,095 MMbbl, and additions to proved plus probable reserves amounted to 1,687 MMbbl. Net positive revisions amounted to 247 MMbbl for proved reserves and 110 MMbbl for proved plus probable reserves, primarily due to technical revisions.

At December 31, 2018, the company gross proved natural gas reserves totaled 6,652 Bcf, and company gross proved plus probable natural gas reserves totaled 9,734 Bcf. Proved reserves additions and revisions replaced 79% of 2018 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 674 Bcf, and additions to proved plus probable reserves amounted to 1,179 Bcf. Net negative revisions amounted to 228 Bcf for proved reserves and 499 Bcf for proved plus probable reserves, primarily due to economic factors.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of the Company's Independent Qualified Reserves Evaluators to review the qualifications of and procedures used by each evaluator in determining the estimate of the Company's quantities and related net present value of future net revenue of the remaining reserves.

Additional reserves disclosure is annually disclosed in the AIF and the "Supplementary Oil and Gas Information" section of the Company's Annual Report.

Risks and Uncertainties

The Company is exposed to various operational risks inherent in the exploration, development, production and marketing of crude oil and NGLs and natural gas and the mining, extracting and upgrading of bitumen into SCO. These inherent risks include, but are not limited to, the following:

- The ability to find, produce and replace reserves, whether sourced from exploration, improved recovery or acquisitions, at a reasonable cost, including the risk of reserves revisions due to economic and technical factors. Reserves revisions can have a positive or negative impact on asset valuations, ARO and depletion rates;
- Reservoir quality and uncertainty of reserves estimates;
- Volatility in the prevailing prices of crude oil and NGLs and natural gas;
- Regulatory risk related to approval for exploration and development activities, which can add to costs or cause delays in projects;
- Labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner;
- Operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting and upgrading the Company's bitumen products;
- Timing and success of integrating the business and operations of acquired companies and assets;
- Credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts, including derivative financial instruments and physical sales contracts as part of a hedging program;
- Interest rate risk associated with the Company's ability to secure financing on commercially acceptable terms;

- Foreign exchange risk due to the effect of fluctuating exchange rates on the Company's US dollar denominated debt and revenue from sales predominantly based on US dollar denominated benchmarks;
- Environmental impact risk associated with exploration and development activities, including GHG;
- Geopolitical risks associated with changing governments or governmental policies, social instability and other political, economic or diplomatic developments in the regions where the Company has its operations;
- Future legislative and regulatory developments related to environmental regulation;
- Potential actions of governments, regulatory authorities and other stakeholders that may result in costs or restrictions in the jurisdictions where the Company has operations, including but not limited to restrictions on production;
- Changing royalty regimes;
- Business interruptions because of unexpected events such as fires or explosions whether caused by human error or nature, severe storms and other calamitous acts of nature, blowouts, freeze-ups, mechanical or equipment failures of facilities and infrastructure and other similar events affecting the Company or other parties whose operations or assets directly or indirectly impact the Company and that may or may not be financially recoverable;
- The ability to secure adequate transportation for products which could be affected by pipeline constraints, the construction by third parties of new or expansion of existing pipeline capacity and other factors;
- The access to markets for the Company's products;
- The risk of significant interruption or failure of the Company's information technology systems and related data and control systems or a significant breach that could adversely affect the Company's operations; and
- Other circumstances affecting revenue and expenses.

The Company uses a variety of means to seek to mitigate and/or minimize these risks. The Company maintains a comprehensive property loss and business interruption insurance program to reduce risk. Operational control is enhanced by focusing efforts on large core areas with high working interests and by assuming operatorship of key facilities. Product mix is diversified, consisting of the production of natural gas and the production of crude oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Accounts receivable from the sale of crude oil and natural gas are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company seeks to manage these risks by monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default. Derivative financial instruments are periodically utilized to help ensure targets are met and to manage commodity price, foreign currency and interest rate exposures. The Company is exposed to possible losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company seeks to manage this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions. The Company has implemented cyber security protocols and procedures designed to reduce the risk of failure or a significant breach of the Company's information technology systems and related data and control systems.

The Company's capital structure mix is also monitored on a continual basis to ensure that it optimizes flexibility, minimizes cost and offers the greatest opportunity for growth. This includes the determination of a reasonable level of debt and any interest rate exposure risk that may exist.

For additional details regarding the Company's risks and uncertainties, refer to the Company's AIF for the year ended December 31, 2018.

Environment

The Company continues to invest in people, technologies, facilities and infrastructure to recover and process crude oil and natural gas resources efficiently and in an environmentally sustainable manner. Environmental, social, economic and health considerations are evaluated in new project designs and in operations to improve environmental performance. Processes are employed to avoid, mitigate, minimize or compensate for environmental effects. Working with local communities, the Company considers the values to the people using the land in proximity to operations and adapts projects in recognition of those values.

The crude oil and natural gas industry is experiencing incremental increases in costs related to environmental regulation, particularly in North America and the North Sea. Existing and expected legislation and regulations require the Company to address and mitigate the effect of its activities on the environment. The Company believes that it meets all existing environmental standards and regulations and has included appropriate amounts in its capital expenditure budget to continue to meet current environmental protection requirements. Increasingly stringent laws and regulations may have an adverse effect on the Company's future net earnings.

The Company's associated environmental risk management strategies focus on working with legislators and regulators to ensure that any new or revised policies, legislation or regulations properly reflect a balanced approach to sustainable development. Specific measures in response to existing or new legislation include a focus on the Company's energy efficiency, air emissions management, water management and land management to minimize disturbance impacts. The Company's environmental risk management strategies employ an Environmental Management Plan (the "Plan"). As part of risk management, the Company develops, assesses and implements technologies and innovative practices that will improve environmental performance, often through collaborative efforts with industry partners, governments and research institutions. Details of the Plan, along with performance results, are presented to, and reviewed by, the Board of Directors quarterly.

The Plan and the Company's operating guidelines focus on minimizing the impact of operations while meeting regulatory requirements, regional management frameworks for air, water and biodiversity, industry operating standards and guidelines, and internal corporate standards. Training and due diligence for operators and contractors is key to the effectiveness of the Company's environmental management programs and the prevention of incidents to protect the environment. The Company, as part of this Plan, has implemented proactive programs that include:

- Environmental planning to assess impacts and implement avoidance and mitigation programs in order to preserve high value biodiversity;
- Continued evaluation of new technologies to reduce environmental impacts, including support for Canada's Oil Sands Innovation Alliance ("COSIA"), Petroleum Technology Alliance Canada ("PTAC") and other research institutions;
- CO_2 reduction programs including carbon capture, CO_2 injection for EOR, CO_2 sequestration in tailings and the Quest carbon capture and storage facility;
- A methane emission reduction program, including solution gas conservation to reduce methane venting, and an equipment retrofit program to reduce methane emissions from pneumatic equipment;
- Optimization of efficiencies at the Company's facilities;
- Water programs to improve efficiency of use and recycle rates as well as to reduce fresh water use;
- An effective reclamation and decommissioning program across the Company's operations, returning sites to their former state. In North America, well abandonment and progressive reclamation of large contiguous areas of land advances biodiversity and establishes functional wildlife habitats;
- Tailings management in Oil Sands Mining to minimize fine tailings and promote reclamation;
- Monitoring programs to assess changes to biodiversity, wildlife and fisheries in order to manage construction and operation effects and to assess reclamation success;
- Participation and support for the Oil Sands Monitoring Program of regional important resources;
- Groundwater monitoring for all thermal in situ and mine operations;
- An active spill prevention and management program; and
- An internal environmental compliance audit and inspection program of operating facilities.

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 5.0% (2017 – 4.7%; 2016 – 5.2%). For 2018, the Company's capital expenditures included $290 million for abandonment expenditures (2017 – $274 million; 2016 – $267 million). The Company's estimated discounted ARO at December 31, 2018 was as follows:

($ millions)	**2018**	2017
Exploration and Production		
North America	**$ 1,665**	$ 1,840
North Sea	**707**	755
Offshore Africa	**134**	245
Oil Sands Mining and Upgrading	**1,379**	1,486
Midstream	**1**	1
	$ 3,886	$ 4,327

The discounted ARO was based on estimates of future costs to abandon and restore wells, production facilities, mine sites, upgrading facilities and tailings, and offshore production platforms. Factors that affect costs include number of wells drilled, well depth, facility size and the specific environmental legislation. The estimated future costs are based on engineering estimates of current costs in accordance with present legislation, industry operating practice and the expected timing of abandonment. The Company's strategy in the North Sea consists of developing commercial hubs around its core operated properties with the goal of increasing production and extending the economic lives of its production facilities, thereby delaying the eventual abandonment dates.

GREENHOUSE GAS AND OTHER AIR EMISSIONS

As a result of the Company's large, diversified and balanced portfolio and its defined pathway to drive long-term emissions reductions through technology and innovation, the Company is well-positioned to be resilient in a lower carbon economy.

The Company, through the Canadian Association of Petroleum Producers, is working with Canadian legislators and regulators as they develop and implement new GHG emission laws and regulations. Internally, the Company is pursuing an integrated emissions reduction strategy, to ensure that it is able to comply with existing and future emissions reduction requirements, for both GHGs and air pollutants (such as sulphur dioxide and oxides of nitrogen). The Company continues to develop strategies that will enable it to deal with the risks and opportunities associated with new GHG and air emissions policies. In addition, the Company is working with relevant parties to ensure that new policies encourage technological innovation, energy efficiency, and targeted research and development while not impacting competitiveness. The Company's integrated GHG emissions reduction strategy includes: 1) integrating emission reduction in project planning and operations; 2) leveraging technology to create value and enhance performance; 3) investing in research and development and supporting collaboration; 4) focusing on continuous improvement to drive long-term emissions reduction; 5) leading in carbon capture and sequestration/storage; 6) engaging proactively in policy and regulatory development (including trading capacity and offsetting emissions); and, 7) considering and developing new business opportunities and trends.

In Canada, the federal government has ratified the Paris climate change agreement, with a commitment to reduce GHG emissions by 30% from 2005 levels by 2030. Canada has also committed to reduce methane emissions from the upstream oil and gas sector by 40 - 45% by 2025, as compared to 2012 levels. The federal government is also developing a comprehensive management system for air pollutants and has released regulations pertaining to certain boilers, heaters and compressor engines operated by the Company. The federal government is also developing a Clean Fuel Standard which may affect production and consumption of fuels in Canada. Effective January 1, 2018, the Alberta government implemented the Carbon Competitiveness Incentive Regulation (CCIR) to replace the Specified Gas Emitters Regulation, for the regulation of GHG emissions from large facilities. The Alberta government has also finalized regulations to reduce methane emissions from the upstream oil and gas sector (consistent with the federal reduction target), with the first regulatory requirements coming into effect January 1, 2020. A previously announced carbon price on combustion emissions from the upstream oil and gas sector is scheduled to begin in 2023. In British Columbia, the provincial government has announced a methane reduction target, comparable to the federal target, and has released final regulations to achieve this target. The Saskatchewan government has also released a regulation to reduce methane emissions from oil production facilities, effective 2020.

In Alberta, GHG reduction regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e annually, and those facilities that elect to "opt-in" to the regulation. The carbon price in Alberta is currently $30/tonne for emissions above the regulated limits. Eight of the Company's operated facilities (the facilities at Horizon and AOSP, the Primrose/Wolf Lake in situ heavy crude oil facilities, the Kirby South in situ heavy crude oil facility, the Peace River in situ heavy crude oil facility, the Hays sour natural gas plant, the Wapiti gas plant, and the Brintnell power generation facility) are subject to compliance under the regulation. The non-operated Scotford Upgrader is also subject to compliance under the regulations. The non-operated North West Redwater bitumen upgrader and refinery became subject to a reduction target on January 1, 2019. In British Columbia, carbon tax is currently being assessed at $35/tonne of CO_2e on fuel consumed and gas flared in the province, with the rate increasing to $40/tonne on April 1, 2019. The British Columbia Government will be increasing the carbon tax at a rate of $5 per tonne of CO_2e annually to $50 per tonne of CO_2e on April 1, 2021. The British Columbia government is implementing a program (the CleanBC Plan) to partially mitigate the impact of the carbon tax increases on emission intensive trade exposed (EITE) sectors. The Saskatchewan government has released a regulation that applies to facilities emitting more than 25 kilotonnes of CO_2e annually and will require the North Tangleflags in situ heavy oil facility and the Senlac in situ heavy oil facility to meet reduction targets for GHG emissions effective 2019. The government of Canada has determined that a federal "backstop" carbon pricing system will apply beginning in 2019 in specific provinces and territories within Canada, including the provinces of Saskatchewan and Manitoba in which the Company operates. The federal backstop system will consist of an output-based pricing system for facilities that emit more than 25 kilotonnes CO_2e annually, and a fuel charge that applies to facilities with emissions below this level.

In the UK, GHG regulations have been in effect since 2005. In Phase 1 (2005 – 2007) of the UK National Allocation Plan, the Company operated below its CO_2 allocation. In Phase 2 (2008 – 2012) the Company's CO_2 allocation was decreased below the Company's operations emissions. In Phase 3 (2013 – 2020) the Company's CO_2 allocation was further reduced. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO_2 emissions at its offshore facilities and on trading mechanisms to ensure compliance with requirements now in effect.

Air pollutant standards and guidelines are being developed federally and provincially and the Company is participating in these discussions. Ambient air quality and sector based reductions in air emissions are being reviewed. Through Company and industry participation with stakeholders, guidelines are being developed that adopt a structured process to emission reductions that is commensurate with technological development and operational requirements.

Accounting Policies and Standards

CHANGES IN ACCOUNTING POLICIES

IFRS 15 "Revenue from Contracts with Customers"

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers" to provide guidance on the recognition of revenue and cash flows arising from an entity's contracts with customers, and related disclosures. The new standard replaces several existing standards related to recognition of revenue and states that revenue should be recognized as performance obligations related to the goods or services delivered are settled. IFRS 15 also provides revenue accounting guidance for contract modifications and multiple-element contracts and prescribes additional disclosure requirements.

The Company adopted IFRS 15 on January 1, 2018 using the retrospective with cumulative effect method. There were no changes to reported net earnings (loss) or retained earnings as a result of adopting IFRS 15. Under the standard, the Company is required to provide additional disclosure of disaggregated revenue by major product type. In connection with adoption of the standard, the Company has reclassified certain comparative amounts in a manner consistent with the presentation adopted for the year ended December 31, 2018. For details refer to note 2 of the Company's audited consolidated financial statements as at December 31, 2018.

Upon adoption of IFRS 15, the Company applied the practical expedient such that contracts that were completed in the comparative periods have not been restated. Applying this expedient had no impact to the revenue recognized under the previous revenue accounting standard as all performance obligations had been met and the consideration had been determined.

IFRS 9 "Financial Instruments"

Effective January 1, 2014, the Company adopted the version of IFRS 9 "Financial Instruments" issued November 2013. In July 2014, the IASB issued amendments to IFRS 9 to include accounting guidance to assess and recognize impairment losses on financial assets based on an expected loss model.

The Company retrospectively adopted the amendments to IFRS 9 on January 1, 2018 and elected to apply the limited exemption in IFRS 9 relating to transition for impairment. Accordingly, provisions for impairment have not been restated in the comparative periods. Adoption of the amendment did not have a significant impact on the Company's previous accounting for impairment of financial assets.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In October 2018, the IASB issued amendments to IFRS 3 "Definition of a Business" that narrowed and clarified the definition of a business. The amendments also permit a simplified assessment of whether an acquired set of activities and assets is a group of assets rather than a business. The amendments are effective January 1, 2020 with earlier adoption permitted. The amendments apply to business combinations after the date of adoption. The Company is assessing the impact of these amendments on its consolidated financial statements.

In October 2018, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" and IAS 8 "Accounting Policies, Changes in Accounting Estimates and Errors". The amendments make minor changes to the definition of the term "material" and align the definition across all IFRS Standards. Materiality is used in making judgments related to the preparation of financial statements. The amendments are effective January 1, 2020 with earlier adoption permitted. The Company is assessing the impact of these amendments on its consolidated financial statements.

In October 2017, the IASB issued amendments to IAS 28 "Investments in Associates and Joint Ventures" to clarify that the impairment provisions in IFRS 9 apply to financial instruments in an associate or joint venture that are not accounted for using the equity method, including long-term assets that form part of the net investment in the associate or joint venture. The amendments are effective January 1, 2019 with earlier adoption permitted. The amendments are required to be adopted retrospectively. The Company has determined that these amendments have no significant impact on its consolidated financial statements.

In June 2017, the IASB issued IFRIC 23 "Uncertainty over Income Tax Treatments". The interpretation provides guidance on how to reflect the effects of uncertainty in accounting for income taxes where IAS 12 is unclear. The interpretation is effective January 1, 2019. The Company has determined that this interpretation has no significant impact on its consolidated financial statements.

IFRS 16 "Leases"

In January 2016, the IASB issued IFRS 16 "Leases", which provides guidance on accounting for leases. The new standard replaces IAS 17 "Leases" and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees and requires balance sheet recognition for all leases. Certain short-term (less than 12 months) and low-value leases (as defined in the standard) are exempt from the requirements, and may continue to be treated as an expense. Leases to explore for or use crude oil, natural gas, minerals and similar non-regenerative resources are exempt from the standard.

The Company will adopt IFRS 16 on January 1, 2019 using the retrospective with cumulative effect method with no impact to opening retained earnings at the date of adoption. In accordance with the transitional provisions in the standard, balances reported in the comparative periods will not be restated.

On initial adoption, the Company intends to use the following practical expedients under the standard. Certain expedients are on a lease-by-lease basis and others are applicable by class of underlying assets:

- the use of a single discount rate to a portfolio of leases with reasonably similar characteristics;
- leases with a remaining lease term of less than twelve months as at January 1, 2019 will be treated as short- term leases; and
- exclusion of indirect costs for the measurement of lease assets at the date of initial application.

The Company does not intend to apply any practical expedients pertaining to grandfathering of leases assessed under the previous standard.

On adoption of IFRS 16, the Company will recognize lease assets and liabilities at the present value of the remaining lease payments, discounted using the Company's applicable borrowing rate on January 1, 2019. The Company expects to report additional lease assets and corresponding liabilities of between $1.5 billion and $1.6 billion. The Company continues to finalize its accounting for leases in accordance with IFRS 16, and the above estimates are subject to change based on finalization of the Company's review of its lease arrangements.

In the statement of earnings, depletion, depreciation and amortization expense and interest expense will increase, with corresponding decreases in production, transportation and administration expenses. The Company does not expect to report a material impact on net earnings. Under the new standard, the Company will report cash outflows for repayment of the principal portion of the lease liability as cash flows from financing activities. The interest portion of the lease payments will continue to be classified as cash flows from operating activities.

Where the Company, acting as the operator, signs a lease on behalf of a joint operation and assumes the legal liability for that lease, the Company will recognize 100% of the related lease asset and lease liability. As the Company recovers its joint operation partners' share of the costs of the lease contract, these recoveries will be recognized in the consolidated statements of earnings.

The Company continues to finalize its evaluation of its contracts that are potentially leases under IFRS 16, as well as implementing changes to policies, internal controls, information systems, and business accounting processes.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. Actual results may differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in this MD&A and the audited consolidated financial statements for the year ended December 31, 2018.

A) Depletion, Depreciation and Amortization and Impairment

Exploration and evaluation ("E&E") costs relating to activities to explore and evaluate crude oil and natural gas properties are initially capitalized and include costs directly associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and evaluation, overhead and administration expenses, and the estimate of any asset retirement costs. E&E assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined. Technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when an assessment of proved reserves is made. The judgements associated with the estimation of proved reserves are described below in "Crude Oil and Natural Gas Reserves".

An alternative acceptable accounting method for E&E costs under IFRS 6 "Exploration for and Evaluation of Mineral Resources" is to charge exploratory dry holes and geological and geophysical exploration costs incurred after having obtained the legal rights to explore an area against net earnings in the period incurred rather than capitalizing to E&E assets.

E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of related Cash Generating Units ("CGUs"), aggregated at a segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated probable reserves volumes, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. The determination of the fair value of CGUs requires the use of assumptions and estimates including future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and production costs, discount rates and income taxes. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. Crude oil and natural gas properties in the Exploration and Production segments are depleted using the unit-of-production method over proved reserves, except for major components, which are depreciated using a straight-line method over their estimated useful lives. The unit-of-production depletion rate takes into account expenditures incurred to date, together with future estimated development expenditures required to develop proved reserves. Estimates of proved reserves have a significant impact on net earnings, as they are a key input to the calculation of depletion expense.

The Company assesses property, plant and equipment for impairment discounted at rates currently ranging from 10% to 12% whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low commodity prices for an extended period, significant downward revisions of estimated reserves volumes, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If an indication of impairment exists, the Company performs an impairment test related to the specific assets at the CGU level.

B) Crude Oil and Natural Gas Reserves

Reserves estimates are based on engineering data, estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures, all of which are subject to many uncertainties, interpretations and judgements. The Company expects that, over time, its reserves estimates will be revised upward or downward based on updated information. Reserves estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion, depreciation and amortization and for determining potential asset impairment. For example, a revision to the proved reserves estimates would result in a higher or lower depletion, depreciation and amortization charge to net earnings. Downward revisions to reserves estimates may also result in an impairment of E&E and property, plant and equipment carrying amounts.

C) Asset Retirement Obligations

The Company is required to recognize a liability for ARO associated with its property, plant and equipment. An ARO liability associated with the retirement of a tangible long-lived asset is recognized to the extent of a legal obligation resulting from an existing or enacted law, statute, ordinance or written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the Company's total ARO amount. These individual assumptions may be subject to change.

The estimated present values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. The provision for the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company's weighted average credit-adjusted risk-free interest rate, which is currently 5.0%. Subsequent to initial measurement, the ARO is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes in discount rates or estimated future cash flows are capitalized to or derecognized from property, plant and equipment. Changes in estimates would impact accretion and depletion expense in net earnings. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains or losses on the final settlement of the ARO.

D) Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated income tax effects of temporary differences in the carrying amount of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted as at the date of the balance sheet. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes a liability for a tax filing position based on its assessment of the probability that additional taxes may ultimately be due.

E) Risk Management Activities

The Company periodically uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized in the consolidated balance sheets at their estimated fair value. The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows, discount rates and credit risk. In determining these assumptions, the Company primarily relied on external, readily-observable quoted market inputs including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States forward interest rate yield curves, and Canadian and United States foreign exchange rates, discounted to present value as appropriate. The carrying amount of a risk management liability is adjusted for the Company's own credit risk. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

F) Purchase Price Allocations

Purchase prices related to business combinations are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make estimates, assumptions and judgements regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of crude oil and natural gas properties, together with deferred income tax effects. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future depletion, depreciation and amortization expense and impairment tests.

The Company has made various assumptions in determining the fair values of acquired assets and liabilities. The most significant assumptions and judgements relate to the estimation of the fair value of crude oil and natural gas properties. To determine the fair value of these properties, the Company estimates crude oil and natural gas reserves. Reserves estimates are based on the work performed by the Company's internal engineers and outside consultants. The judgements associated with these estimated reserves are described above in "Crude Oil and Natural Gas Reserves". Estimates of future prices are based on prices derived from price forecasts among industry analysts and internal assessments. The Company applies estimated future prices to the estimated reserves quantities acquired, and estimates future operating and development costs, to arrive at estimated future net revenues for the properties acquired.

G) Share-Based Compensation

The Company has made various assumptions in estimating the fair values of stock options granted including expected volatility, expected exercise behavior and future forfeiture rates. At each period end, stock options outstanding are remeasured for changes in the fair value of the liability.

Control Environment

The Company's management, including the President and the Chief Financial Officer and Senior Vice-President, Finance, evaluated the effectiveness of disclosure controls and procedures as at December 31, 2018, and concluded that disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in its annual filings and other reports filed with securities regulatory authorities in Canada and the United States is recorded, processed, summarized and reported within the time periods specified and such information is accumulated and communicated to the Company's management to allow timely decisions regarding required disclosures.

The Company's management, including the President and the Chief Financial Officer and Senior Vice-President, Finance, also evaluated the effectiveness of internal control over financial reporting as at December 31, 2018, and concluded that internal control over financial reporting is effective. Further, there were no changes in the Company's internal control over financial reporting during 2018 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

While the Company's management believes that the Company's disclosure controls and procedures and internal control over financial reporting provide a reasonable level of assurance they are effective, they recognize that all control systems have inherent limitations. Because of its inherent limitations, the Company's control systems may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Outlook

The Company continues to implement its strategy of maintaining a large portfolio of varied projects, which the Company believes will enable it, over an extended period of time, to provide consistent growth in production and create shareholder value. Annual budgets are developed, scrutinized throughout the year and revised if necessary in the context of targeted financial ratios, project returns, product pricing expectations, and balance in project risk and time horizons. The Company maintains a high ownership level and operatorship level in all of its properties and can therefore control the nature, timing and extent of capital expenditures in each of its project areas.

Capital expenditures in 2019 are currently targeted to be as follows:

($ millions)	2019
Exploration and Production	
North America natural gas and NGLs	$ 365
North America crude oil	775
International crude oil	460
Thermal In Situ Oil Sands	545
Net acquisitions, midstream and other	30
Total Exploration and Production	$ 2,175
Oil Sands Mining and Upgrading	
Strategic, project development, environment and technology	505
Sustaining capital	780
Turnarounds, reclamation and other	240
Total Oil Sands Mining and Upgrading	$ 1,525
Total Capital Expenditures	$ 3,700

Other

SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of cash flows from operating activities and net earnings (loss) due to changes in certain key variables. The analysis is based on business conditions and sales volumes during the fourth quarter of 2018, excluding mark-to-market gains (losses) on risk management activities and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only with all other variables being held constant.

	Cash flows from Operating Activities ($ millions)	Cash flows from Operating Activities (per common share, basic)	Net earnings (loss) ($ millions)	Net earnings (loss) (per common share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl				
Excluding financial derivatives	$ 279	$ 0.23	$ 279	$ 0.23
Including financial derivatives	$ 274	$ 0.22	$ 274	$ 0.22
Natural gas – AECO C$0.10/Mcf [1]				
Excluding financial derivatives	$ 26	$ 0.02	$ 26	$ 0.02
Including financial derivatives	$ 25	$ 0.02	$ 25	$ 0.02
Volume changes				
Crude oil – 10,000 bbl/d	$ 126	$ 0.10	$ 99	$ 0.08
Natural gas – 10 MMcf/d	$ 4	$ –	$ –	$ –
Foreign currency rate change				
$0.01 change in US$ [1]				
Including financial derivatives	$ 157 – 163	$ 0.13	$ 38	$ 0.03
Interest rate change – 1%	$ 37	$ 0.03	$ 37	$ 0.03

(1) For details of financial instruments in place, refer to note 19 to the Company's audited consolidated financial statements as at December 31, 2018.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2018	2017	2016
Crude oil and NGLs (bbl/d)							
North America – Exploration and Production	**357,460**	**343,538**	**359,856**	**343,054**	**350,961**	359,449	350,958
North America – Oil Sands Mining and Upgrading	**456,076**	**407,704**	**394,382**	**447,048**	**426,190**	282,026	123,265
North Sea	**21,584**	**24,456**	**28,702**	**21,071**	**23,965**	23,426	23,554
Offshore Africa	**19,438**	**18,201**	**18,802**	**22,185**	**19,662**	20,335	26,096
Total	**854,558**	**793,899**	**801,742**	**833,358**	**820,778**	685,236	523,873
Natural gas (MMcf/d)							
North America	**1,547**	**1,485**	**1,489**	**1,441**	**1,490**	1,601	1,622
North Sea	**37**	**30**	**38**	**22**	**32**	39	38
Offshore Africa	**30**	**24**	**26**	**25**	**26**	22	31
Total	**1,614**	**1,539**	**1,553**	**1,488**	**1,548**	1,662	1,691
Barrels of oil equivalent (BOE/d)							
North America – Exploration and Production	**615,228**	**590,963**	**608,063**	**583,242**	**599,310**	626,230	621,239
North America – Oil Sands Mining and Upgrading	**456,076**	**407,704**	**394,382**	**447,048**	**426,190**	282,026	123,265
North Sea	**27,740**	**29,485**	**35,076**	**24,727**	**29,264**	29,989	29,913
Offshore Africa	**24,502**	**22,224**	**23,108**	**26,351**	**24,049**	24,019	31,365
Total	**1,123,546**	**1,050,376**	**1,060,629**	**1,081,368**	**1,078,813**	962,264	805,782

PER UNIT RESULTS – EXPLORATION AND PRODUCTION

	Q1	Q2	Q3	Q4	2018	2017	2016
Crude oil and NGLs ($/bbl) [1]							
Sales price [2]	**$ 43.06**	**$ 61.14**	**$ 57.89**	**$ 25.95**	**$ 46.92**	$ 48.57	$ 36.93
Transportation	**3.10**	**3.30**	**3.00**	**2.94**	**3.08**	2.80	2.61
Realized sales price, net of transportation	**39.96**	**57.84**	**54.89**	**23.01**	**43.84**	45.77	34.32
Royalties	**4.87**	**7.56**	**7.08**	**0.92**	**5.08**	5.24	3.40
Production expense	**15.70**	**15.64**	**14.47**	**16.93**	**15.69**	14.89	14.10
Netback	**$ 19.39**	**$ 34.64**	**$ 33.34**	**$ 5.16**	**$ 23.07**	$ 25.64	$ 16.82
Natural gas ($/Mcf) [1]							
Sales price [2]	**$ 2.74**	**$ 1.95**	**$ 2.32**	**$ 3.46**	**$ 2.61**	$ 2.76	$ 2.32
Transportation	**0.51**	**0.51**	**0.42**	**0.42**	**0.47**	0.39	0.33
Realized sales price, net of transportation	**2.23**	**1.44**	**1.90**	**3.04**	**2.14**	2.37	1.99
Royalties	**0.10**	**0.08**	**0.05**	**0.10**	**0.08**	0.11	0.09
Production expense	**1.41**	**1.39**	**1.33**	**1.32**	**1.36**	1.27	1.18
Netback [3]	**$ 0.72**	**$ (0.03)**	**$ 0.52**	**$ 1.62**	**$ 0.70**	$ 0.99	$ 0.72
Barrels of oil equivalent ($/BOE) [1]							
Sales price [2]	**$ 32.02**	**$ 41.63**	**$ 40.77**	**$ 24.04**	**$ 34.62**	$ 35.54	$ 27.58
Transportation	**3.05**	**3.20**	**2.83**	**2.77**	**2.96**	2.66	2.44
Realized sales price, net of transportation	**28.97**	**38.43**	**37.94**	**21.27**	**31.66**	32.88	25.14
Royalties	**3.10**	**4.75**	**4.44**	**0.80**	**3.27**	3.40	2.21
Production expense	**12.68**	**12.75**	**11.91**	**13.51**	**12.71**	11.95	11.18
Netback	**$ 13.19**	**$ 20.93**	**$ 21.59**	**$ 6.96**	**$ 15.68**	$ 17.53	$ 11.75

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.
(3) Natural gas netbacks exclude netbacks derived from the sale of NGLs. Combining natural gas and NGLs, the netback for the three months ended December 31, 2018 was $1.84/Mcfe (September 30, 2018 – $1.05/Mcfe, June 30, 2018 – $0.60/Mcfe, March 31, 2018 – $1.19/Mcfe; year ended December 31, 2018 – $1.18/Mcfe, December 31, 2017 – $1.31/Mcfe, December 31, 2016 – $0.89/Mcfe).

PER UNIT RESULTS – OIL SANDS MINING AND UPGRADING

	Q1	Q2	Q3	Q4	2018	2017	2016
Crude oil and NGLs ($/bbl)							
SCO sales price	**$ 71.61**	**$ 80.17**	**$ 81.69**	**$ 42.73**	**$ 68.61**	$ 63.98	$ 58.59
Bitumen royalties (1)	**1.98**	**4.25**	**4.31**	**2.03**	**3.09**	1.64	0.54
Transportation	**1.54**	**1.63**	**1.73**	**1.56**	**1.61**	1.54	1.77
Adjusted cash production costs (2)	**21.37**	**22.94**	**19.95**	**19.97**	**21.05**	23.40	25.20
Netback	**$ 46.72**	**$ 51.35**	**$ 55.70**	**$ 19.17**	**$ 42.86**	$ 37.40	$ 31.08

(1) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.
(2) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.

TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2018	2017
TSX – C$						
Trading volume (thousands)	**174,140**	**198,092**	**165,227**	**268,795**	**806,254**	588,422
Share Price ($/share)						
High	**$ 46.77**	**$ 48.73**	**$ 49.08**	**$ 43.31**	**$ 49.08**	$ 47.00
Low	**$ 36.88**	**$ 39.15**	**$ 40.71**	**$ 30.11**	**$ 30.11**	$ 35.90
Close	**$ 40.50**	**$ 47.45**	**$ 42.20**	**$ 32.94**	**$ 32.94**	$ 44.92
Market capitalization as at December 31 ($ millions)					**$ 39,590**	$ 54,927
Shares outstanding (thousands)					**1,201,886**	1,222,769
NYSE – US$						
Trading volume (thousands)	**153,374**	**234,303**	**154,675**	**254,619**	**796,971**	608,008
Share Price ($/share)						
High	**$ 37.63**	**$ 38.19**	**$ 37.41**	**$ 33.86**	**$ 38.19**	$ 36.78
Low	**$ 29.21**	**$ 30.26**	**$ 31.29**	**$ 21.85**	**$ 21.85**	$ 27.53
Close	**$ 31.47**	**$ 36.07**	**$ 32.66**	**$ 24.13**	**$ 24.13**	$ 35.72
Market capitalization as at December 31 ($ millions)					**$ 29,002**	$ 43,677
Shares outstanding (thousands)					**1,201,886**	1,222,769

Management's Report

The accompanying consolidated financial statements of Canadian Natural Resources Limited (the "Company") and all other information contained elsewhere in this Annual Report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with the accounting policies described in the accompanying notes. Where necessary, management has made informed judgements and estimates in accounting for transactions that were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board as appropriate in the circumstances. The financial information presented elsewhere in the Annual Report has been reviewed to ensure consistency with that in the consolidated financial statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized and recorded, assets are safeguarded from loss or unauthorized use and financial records are properly maintained to provide reliable information for preparation of financial statements.

PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent Annual General Meeting, to audit and provide their independent audit opinions on the following:

- the Company's consolidated financial statements as at and for the year ended December 31, 2018; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2018.

Their report is presented with the consolidated financial statements.

The Board of Directors (the "Board") is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Board exercises this responsibility through the Audit Committee of the Board, which is comprised entirely of independent directors. The Audit Committee meets with management and the independent auditors to satisfy itself that management responsibilities are properly discharged and to review the consolidated financial statements before they are presented to the Board for approval. The consolidated financial statements have been approved by the Board on the recommendation of the Audit Committee.

TIM S. MCKAY
President

COREY B. BIEBER, CA
Chief Financial Officer and Senior Vice-President, Finance

RONALD D. KIM, CA
Vice-President,
Finance – Corporate

Calgary, Alberta, Canada
March 6, 2019

Management's Assessment of Internal Control over Financial Reporting

Management of Canadian Natural Resources Limited (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting for the Company as defined in Rules 13a-15(f) and 15d-15(f) under the United States Securities Exchange Act of 1934, as amended.

Management, including the Company's President and the Company's Chief Financial Officer and Senior Vice-President, Finance, performed an assessment of the Company's internal control over financial reporting based on the criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Based on the assessment, management has concluded that the Company's internal control over financial reporting is effective as at December 31, 2018. Management recognizes that all internal control systems have inherent limitations. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, has provided an opinion on the Company's internal control over financial reporting as at December 31, 2018, as stated in their accompanying Report of Independent Registered Public Accounting Firm.

Tim McKay

TIM S. MCKAY
President

COREY B. BIEBER, CA
Chief Financial Officer and Senior
Vice-President, Finance

Calgary, Alberta, Canada
March 6, 2019

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of Canadian Natural Resources Limited

OPINIONS ON THE FINANCIAL STATEMENTS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

We have audited the accompanying consolidated balance sheets of Canadian Natural Resources Limited and its subsidiaries (together, the "Company") as of December 31, 2018 and 2017, and the related consolidated statements of earnings (loss), comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2018, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and its financial performance and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS"). Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the COSO.

BASIS FOR OPINIONS

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Assessment of Internal Controls over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

DEFINITION AND LIMITATIONS OF INTERNAL CONTROL OVER FINANCIAL REPORTING

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Canada
March 6, 2019

We have served as the Company's auditor since 1973.

Consolidated Balance Sheets

As at December 31 (millions of Canadian dollars)	Note	2018	2017
ASSETS			
Current assets			
Cash and cash equivalents		**$ 101**	$ 137
Accounts receivable		**1,148**	2,397
Current income taxes receivable		**–**	322
Inventory	5	**955**	894
Prepaids and other		**176**	175
Investments	9	**524**	893
Current portion of other long-term assets	10	**116**	79
		3,020	4,897
Exploration and evaluation assets	6	**2,637**	2,632
Property, plant and equipment	7	**64,559**	65,170
Other long-term assets	10	**1,343**	1,168
		$ 71,559	$ 73,867
LIABILITIES			
Current liabilities			
Accounts payable		**$ 779**	$ 775
Accrued liabilities		**2,356**	2,597
Current income taxes payable		**151**	–
Current portion of long-term debt	11	**1,141**	1,877
Current portion of other long-term liabilities	12	**335**	1,012
		4,762	6,261
Long-term debt	11	**19,482**	20,581
Other long-term liabilities	12	**3,890**	4,397
Deferred income taxes	13	**11,451**	10,975
		39,585	42,214
SHAREHOLDERS' EQUITY			
Share capital	14	**9,323**	9,109
Retained earnings		**22,529**	22,612
Accumulated other comprehensive income (loss)	15	**122**	(68)
		31,974	31,653
		$ 71,559	$ 73,867

Commitments and contingencies (note 20).

Approved by the Board of Directors on March 6, 2019

CATHERINE M. BEST
Chair of the Audit
Committee and Director

N. MURRAY EDWARDS
Executive Chairman of the Board of
Directors and Director

Consolidated Statements of Earnings (Loss)

For the years ended December 31 (millions of Canadian dollars, except per common share amounts)	Note		2018		2017 (1)		2016 (1)
Product sales	22	$	**22,282**	$	18,360	$	12,002
Less: royalties			**(1,255)**		(1,018)		(575)
Revenue			**21,027**		17,342		11,427
Expenses							
Production			**6,464**		5,675		4,184
Transportation, blending and feedstock			**4,189**		3,529		2,822
Depletion, depreciation and amortization	6, 7		**5,161**		5,186		4,858
Administration			**325**		319		345
Share-based compensation	12		**(146)**		134		355
Asset retirement obligation accretion	12		**186**		164		142
Interest and other financing expense	18		**739**		631		383
Risk management activities	19		**(134)**		35		33
Foreign exchange loss (gain)			**827**		(787)		(55)
Gain on acquisition, disposition and revaluation of properties	6, 7, 8		**(452)**		(379)		(250)
Loss (gain) from investments	9, 10		**346**		(38)		(327)
			17,505		14,469		12,490
Earnings (loss) before taxes			**3,522**		2,873		(1,063)
Current income tax expense (recovery)	13		**374**		(164)		(618)
Deferred income tax expense (recovery)	13		**557**		640		(241)
Net earnings (loss)		$	**2,591**	$	2,397	$	(204)
Net earnings (loss) per common share							
Basic	17	$	**2.13**	$	2.04	$	(0.19)
Diluted	17	$	**2.12**	$	2.03	$	(0.19)

(1) In connection with adoption of IFRS 15 on January 1, 2018, the Company has reclassified certain comparative amounts in a manner consistent with the presentation adopted for the year ended December 31, 2018 (see note 2).

Consolidated Statements of Comprehensive Income (Loss)

For the years ended December 31 (millions of Canadian dollars)		2018		2017		2016
Net earnings (loss)	$	**2,591**	$	2,397	$	(204)
Items that may be reclassified subsequently to net earnings (loss)						
Net change in derivative financial instruments designated as cash flow hedges						
Unrealized income (loss), net of taxes of $nil (2017 – $9 million, 2016 – $3 million)		**5**		53		(18)
Reclassification to net earnings (loss), net of taxes of $6 million (2017 – $5 million, 2016 – $2 million)		**(39)**		(33)		(13)
		(34)		20		(31)
Foreign currency translation adjustment						
Translation of net investment		**224**		(158)		26
Other comprehensive income (loss), net of taxes		**190**		(138)		(5)
Comprehensive income (loss)	$	**2,781**	$	2,259	$	(209)

Consolidated Statements of Changes in Equity

For the years ended December 31 (millions of Canadian dollars)	Note	2018	2017	2016
Share capital	14			
Balance – beginning of year		**$ 9,109**	$ 4,671	$ 4,541
Issued for the acquisition of AOSP and other assets [1]	8	**–**	3,818	–
Issued upon exercise of stock options		**332**	466	559
Previously recognized liability on stock options exercised for common shares		**120**	154	117
Purchase of common shares under Normal Course Issuer Bid		**(238)**	–	–
Return of capital on PrairieSky Royalty Ltd. share distribution		**–**	–	(546)
Balance – end of year		**9,323**	9,109	4,671
Retained earnings				
Balance – beginning of year		**22,612**	21,526	22,765
Net earnings (loss)		**2,591**	2,397	(204)
Purchase of common shares under Normal Course Issuer Bid	14	**(1,044)**	–	–
Dividends on common shares	14	**(1,630)**	(1,311)	(1,035)
Balance – end of year		**22,529**	22,612	21,526
Accumulated other comprehensive income (loss)	15			
Balance – beginning of year		**(68)**	70	75
Other comprehensive income (loss), net of taxes		**190**	(138)	(5)
Balance – end of year		**122**	(68)	70
Shareholders' equity		**$ 31,974**	$ 31,653	$ 26,267

(1) During 2017, in connection with the acquisition of direct and indirect interests in the Athabasca Oil Sands Project ("AOSP") and other assets, the Company issued non-cash share consideration of $3,818 million. See note 8.

Consolidated Statements of Cash Flows

For the years ended December 31 (millions of Canadian dollars)	Note	2018	2017	2016
Operating activities				
Net earnings (loss)		**$ 2,591**	$ 2,397	$ (204)
Non-cash items				
Depletion, depreciation and amortization		**5,161**	5,186	4,858
Share-based compensation		**(146)**	134	355
Asset retirement obligation accretion		**186**	164	142
Unrealized risk management (gain) loss		**(35)**	37	25
Unrealized foreign exchange loss (gain)		**706**	(821)	(93)
Realized foreign exchange loss on repayment of US dollar debt securities		**146**	–	–
Gain on acquisition, disposition and revaluation of properties		**(452)**	(379)	(250)
Loss (gain) from investments		**374**	(11)	(299)
Deferred income tax expense (recovery)		**557**	640	(241)
Other		**(23)**	(110)	(32)
Abandonment expenditures		**(290)**	(274)	(267)
Net change in non-cash working capital	21	**1,346**	299	(542)
Cash flows from operating activities		**10,121**	7,262	3,452
Financing activities				
(Repayment) issue of bank credit facilities and commercial paper, net	11, 21	**(1,595)**	2,222	342
Issue of medium-term notes, net	11, 21	**–**	1,791	998
(Repayment) issue of US dollar debt securities, net	11, 21	**(1,236)**	2,733	(834)
Issue of common shares on exercise of stock options		**332**	466	559
Purchase of common shares under Normal Course Issuer Bid		**(1,282)**	–	–
Dividends on common shares		**(1,562)**	(1,252)	(758)
Cash flows (used in) from financing activities		**(5,343)**	5,960	307
Investing activities				
Net (expenditures) proceeds on exploration and evaluation assets	21	**(266)**	(124)	6
Net expenditures on property, plant and equipment (1)	21	**(4,175)**	(4,574)	(3,803)
Acquisition of AOSP and other assets, net of cash acquired (2)	8	**–**	(8,630)	–
Investment in other long-term assets		**(28)**	(87)	(99)
Net change in non-cash working capital	21	**(345)**	313	85
Cash flows used in investing activities		**(4,814)**	(13,102)	(3,811)
(Decrease) increase in cash and cash equivalents		**(36)**	120	(52)
Cash and cash equivalents – beginning of year		**137**	17	69
Cash and cash equivalents – end of year		**$ 101**	$ 137	$ 17
Interest paid, net		**$ 911**	$ 725	$ 617
Income taxes received		**$ (225)**	$ (792)	$ (444)

(1) Net expenditures on property, plant and equipment in 2016 exclude non-cash share consideration of $190 million received from Inter Pipeline Ltd. ("Inter Pipeline") on the disposition of the Company's interest in the Cold Lake Pipeline.

(2) The acquisition of AOSP in 2017 includes net working capital of $291 million and excludes non-cash share consideration of $3,818 million. See note 8.

Notes to the Consolidated Financial Statements

(tabular amounts in millions of Canadian dollars, unless otherwise stated)

1. Accounting Policies

Canadian Natural Resources Limited (the "Company") is a senior independent crude oil and natural gas exploration, development and production company. The Company's exploration and production operations are focused in North America, largely in Western Canada; the United Kingdom ("UK") portion of the North Sea; and Côte d'Ivoire, Gabon, and South Africa in Offshore Africa.

The "Oil Sands Mining and Upgrading" segment produces synthetic crude oil through bitumen mining and upgrading operations at Horizon Oil Sands ("Horizon") and through the Company's direct and indirect interest in AOSP.

Within Western Canada, the Company maintains certain midstream activities that include pipeline operations, an electricity co-generation system and an investment in the North West Redwater Partnership ("Redwater Partnership"), a general partnership formed in the Province of Alberta.

The Company was incorporated in Alberta, Canada. The address of its registered office is 2100, 855 – 2 Street S.W., Calgary, Alberta, Canada.

The Company's consolidated financial statements and the related notes have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). The accounting policies adopted by the Company under IFRS are set out below. The Company has consistently applied the same accounting policies throughout all periods presented, except where IFRS permits new accounting standards to be adopted prospectively. Changes in the Company's accounting policies are discussed in note 2.

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements have been prepared under the historical cost basis, unless otherwise required.

The consolidated financial statements include the accounts of the Company and all of its subsidiary companies and wholly owned partnerships. Subsidiaries include all entities over which the Company has control. Subsidiaries are consolidated from the date on which the Company obtains control. They are deconsolidated from the date that control ceases.

Certain of the Company's activities are conducted through joint arrangements in which two or more parties have joint control. Where the Company has determined that it has a direct ownership interest in jointly controlled assets and obligations for the liabilities (a "joint operation"), the assets, liabilities, revenue and expenses related to the joint operation are included in the consolidated financial statements in proportion to the Company's interest. Where the Company has determined that it has an interest in jointly controlled entities (a "joint venture"), it uses the equity method of accounting. Under the equity method, the Company's initial and subsequent investments are recognized at cost and subsequently adjusted for the Company's share of the joint venture's income or loss, less distributions received.

Joint ventures accounted for using the equity method of accounting are tested for impairment whenever objective evidence indicates that the carrying amount of the investment may not be recoverable. Indications of impairment include a history of losses, significant capital expenditure overruns, liquidity concerns, financial restructuring of the investee or significant adverse changes in the technological, economic or legal environment. The amount of the impairment is measured as the difference between the carrying amount of the investment and the higher of its fair value less costs of disposal and its value in use. Impairment losses are reversed in subsequent periods if the amount of the loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized.

(B) SEGMENTED INFORMATION

Operating segments have been determined based on the nature of the Company's activities and the geographic locations in which the Company operates, and are consistent with the level of information regularly provided to and reviewed by the Company's chief operating decision makers.

(C) CASH AND CASH EQUIVALENTS

Cash comprises cash on hand and demand deposits. Other investments (term deposits and certificates of deposit) with an original term to maturity at purchase of three months or less are reported as cash equivalents in the consolidated balance sheets.

(D) INVENTORY

Inventory is primarily comprised of product inventory and materials and supplies and is carried at the lower of cost and net realizable value. Product inventory is comprised of crude oil held for sale, including pipeline linefill and crude oil stored in floating production, storage and offloading vessels. Cost of product inventory consists of purchase costs, direct production costs, directly attributable overhead and depletion, depreciation and amortization and is determined on a first-in, first-out basis. Net realizable value for product inventory is determined by reference to forward prices. Cost for materials and supplies consists of purchase costs and is based on a first-in, first-out or an average cost basis. Net realizable value for materials and supplies is determined by reference to current market prices.

(E) EXPLORATION AND EVALUATION ASSETS

Exploration and evaluation ("E&E") assets consist of the Company's crude oil and natural gas exploration projects that are pending the determination of proved reserves.

E&E costs are initially capitalized and include costs directly associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and evaluation, overhead and administration expenses, and the estimate of any asset retirement costs. E&E costs do not include general prospecting or evaluation costs incurred prior to having obtained the legal rights to explore an area. These costs are recognized in net earnings.

Once the technical feasibility and commercial viability of E&E assets are determined and a development decision is made by management, the E&E assets are tested for impairment upon reclassification to property, plant and equipment. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when an assessment of proved reserves is made. An E&E asset is derecognized upon disposal or when no future economic benefits are expected to arise from its use. Any gain or loss arising on derecognition of the asset is recognized in net earnings within depletion, depreciation and amortization.

E&E assets are also tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of the related Cash Generating Units ("CGUs"), aggregated at a segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated probable reserves volumes, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks.

(F) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. Assets under construction are not depleted or depreciated until available for their intended use. The capitalized value of a finance lease is included in property, plant and equipment.

Exploration and Production

The cost of an asset comprises its acquisition costs, construction and development costs, costs directly attributable to bringing the asset into operation, the estimate of any asset retirement costs, and applicable borrowing costs. Property acquisition costs are comprised of the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

When significant components of an item of property, plant and equipment, including crude oil and natural gas interests, have different useful lives, they are accounted for separately.

Crude oil and natural gas properties are depleted using the unit-of-production method over proved reserves, except for major components, which are depreciated using a straight-line method over their estimated useful lives. The unit-of-production depletion rate takes into account expenditures incurred to date, together with future development expenditures required to develop proved reserves.

Oil Sands Mining and Upgrading

Capitalized costs for the Oil Sands Mining and Upgrading segment are reported separately from the Company's North America Exploration and Production segment. Capitalized costs include acquisition costs, construction and development costs, costs directly attributable to bringing the asset into operation, the estimate of any asset retirement costs, and applicable borrowing costs.

Mine-related costs are depleted using the unit-of-production method based on proved reserves. Costs of the upgraders and related infrastructure located on the Horizon and AOSP sites are depreciated on the unit-of-production method based on the estimated productive capacity of the respective upgraders and related infrastructure. Other equipment is depreciated on a straight-line basis over its estimated useful life ranging from 2 to 18 years.

Midstream and Head Office

The Company capitalizes all costs that expand the capacity or extend the useful life of the midstream and head office assets. Midstream assets are depreciated on a straight-line basis over their estimated useful lives ranging from 5 to 30 years. Head office assets are depreciated on a declining balance basis.

Useful lives

The depletion rates and expected useful lives of property, plant and equipment are reviewed on an annual basis, with changes in depletion rates and useful lives accounted for prospectively.

Derecognition

A property, plant and equipment asset is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the asset) is recognized in net earnings within depletion, depreciation and amortization.

Major maintenance expenditures

Inspection costs associated with major maintenance turnarounds are capitalized and depreciated over the period to the next major maintenance turnaround. All other maintenance costs are expensed as incurred.

Impairment

The Company assesses property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low benchmark commodity prices for an extended period of time, significant downward revisions of estimated reserves volumes, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If an indication of impairment exists, the Company performs an impairment test related to the assets. Individual assets are grouped for impairment assessment purposes into CGUs, which are the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. A CGU's recoverable amount is the higher of its fair value less costs of disposal and its value in use. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount through depletion, depreciation and amortization expense.

In subsequent periods, an assessment is made at each reporting date to determine whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the recoverable amount is re-estimated and the net carrying amount of the asset is increased to its revised recoverable amount. The revised recoverable amount cannot exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, had no impairment loss been recognized for the asset in prior periods. A reversal of impairment is recognized in net earnings. After a reversal, the depletion, depreciation and amortization charge is adjusted in future periods to allocate the asset’s revised carrying amount over its remaining useful life.

(G) BUSINESS COMBINATIONS

Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed in a business combination are recognized at their fair value at the date of the acquisition. Any excess of the consideration paid over the fair value of the net assets acquired is recognized as an asset. Any excess of the fair value of the net assets acquired over the consideration paid is recognized in net earnings.

(H) OVERBURDEN REMOVAL COSTS

Overburden removal costs incurred during the initial development of a mine at Horizon and AOSP are capitalized to property, plant and equipment. Overburden removal costs incurred during the production of a mine are included in the cost of inventory, unless the overburden removal activity has resulted in a probable inflow of future economic benefits to the Company, in which case the costs are capitalized to property, plant and equipment. Capitalized overburden removal costs are depleted over the life of the mining reserves that directly benefit from the overburden removal activity.

(I) CAPITALIZED BORROWING COSTS

Borrowing costs attributable to the acquisition, construction or production of qualifying assets are capitalized to the cost of those assets until such time as the assets are substantially available for their intended use. Qualifying assets are comprised of those significant assets that require a period greater than one year to be available for their intended use. All other borrowing costs are recognized in net earnings.

(J) LEASES

Finance leases, which transfer substantially all of the risks and rewards incidental to ownership of the leased item to the Company, are capitalized at the commencement of the lease term at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term. Operating lease payments are recognized in net earnings over the lease term. The Company adopted IFRS 16 on January 1, 2019 (see note 3).

(K) ASSET RETIREMENT OBLIGATIONS

The Company provides for asset retirement obligations on all of its property, plant and equipment and certain exploration and evaluation assets based on current legislation and industry operating practices. Provisions for asset retirement obligations related to property, plant and equipment are recognized as a liability in the period in which they are incurred. Provisions are measured at the present value of management's best estimate of expenditures required to settle the obligation as at the date of the balance sheets. Subsequent to the initial measurement, the obligation is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes due to discount rates or estimated future cash flows are capitalized to or derecognized from property, plant and equipment. Actual costs incurred upon settlement of the asset retirement obligation are charged against the provision.

(L) FOREIGN CURRENCY TRANSLATION

Functional and presentation currency

Items included in the financial statements of the Company's subsidiary companies and partnerships are measured using the currency of the primary economic environment in which the subsidiary operates (the "functional currency"). The consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency.

The assets and liabilities of subsidiaries that have a functional currency different from that of the Company are translated into Canadian dollars at the closing rate at the date of the balance sheets, and revenue and expenses are translated at the average rate for the period. Cumulative foreign currency translation adjustments are recognized in other comprehensive income.

When the Company disposes of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the foreign currency gains or losses accumulated in other comprehensive income related to the foreign operation are recognized in net earnings.

Transactions and balances

Foreign currency transactions are translated into the functional currency of the Company and its subsidiaries and partnerships using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of foreign currency transactions and from the translation at balance sheet date exchange rates of monetary assets and liabilities denominated in currencies other than the functional currency are recognized in net earnings.

(M) REVENUE RECOGNITION AND COSTS OF GOODS SOLD

Revenue from the sale of crude oil and NGLs and natural gas products is recognized when performance obligations in the sales contract are satisfied and it is probable that the Company will collect the consideration to which it is entitled. Performance obligations are generally satisfied at the point in time when the product is delivered to a location specified in a contract and control passes to the customer. The Company assesses customer creditworthiness, both before entering into contracts and throughout the revenue recognition process.

Contracts for sale of the Company's products generally have terms of less than a year, with certain contracts extending beyond one year. Contracts in North America generally specify delivery of crude oil and NGLs and natural gas throughout the term of the contract. Contracts in the North Sea and Offshore Africa generally specify delivery of crude oil at a point in time.

Sales of the Company's crude oil and NGLs and natural gas products to customers are made pursuant to contracts based on prevailing commodity pricing at or near the time of delivery and volumes of product delivered. Revenues are typically collected in the month following delivery and accordingly, the Company has elected to apply the practical expedient to not adjust consideration for the effects of a financing component. Purchases and sales of crude oil and NGLs and natural gas with the same counterparty, made to facilitate sales to customers or potential customers, that are entered into in contemplation of one another, are combined and recorded as non-monetary exchanges and measured at the net settlement amount.

Revenue in the consolidated statement of earnings represents the Company's share of product sales net of royalty payments to governments and other mineral interest owners. The Company discloses the disaggregation of revenues from sales of crude oil and NGLs and natural gas in the segmented information in note 22. Related costs of goods sold are comprised of production, transportation, blending and feedstock, and depletion, depreciation and amortization expenses. These amounts have been separately presented in the consolidated statements of earnings.

The Company continues to report revenue for the years ended December 31, 2017 and 2016 in accordance with the Company's previous accounting policy for revenue and cost of goods sold as follows:

Revenue from the sale of crude oil and natural gas is recognized when title passes to the customer, delivery has taken place and collection is reasonably assured. The Company assesses customer creditworthiness, both before entering into contracts and throughout the revenue recognition process.

(N) PRODUCTION SHARING CONTRACTS

Production generated from Côte d'Ivoire and Gabon in Offshore Africa is shared under the terms of various Production Sharing Contracts ("PSCs"). Product sales are divided into cost recovery oil and profit oil. Cost recovery oil allows the Company to recover its capital and production costs and the costs carried by the Company on behalf of the respective government state oil companies (the "Governments"). Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Governments. The Governments' share of profit oil attributable to the Company's equity interest is allocated to royalty expense and current income tax expense in accordance with the terms of the respective PSCs.

(O) INCOME TAX

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated income tax effects of temporary differences in the carrying amount of assets and liabilities in the consolidated financial statements and their respective tax bases.

Deferred income tax assets and liabilities are calculated using the substantively enacted income tax rates that are expected to apply when the asset or liability is recovered. Deferred income tax assets or liabilities are not recognized when they arise on the initial recognition of an asset or liability in a transaction (other than in a business combination) that, at the time of the transaction, affects neither accounting nor taxable profit. Deferred income tax assets or liabilities are also not recognized on possible future distributions of retained earnings of subsidiaries where the timing of the distribution can be controlled by the Company and it is probable that a distribution will not be made in the foreseeable future, or when distributions can be made without incurring income taxes.

Deferred income tax assets for deductible temporary differences and tax loss carryforwards are recognized to the extent that it is probable that future taxable profits will be available against which the temporary differences or tax loss carryforwards can be utilized. The carrying amount of deferred income tax assets is reviewed at each reporting date, and is reduced if it is no longer probable that sufficient future taxable profits will be available against which the temporary differences or tax loss carryforwards can be utilized.

Current income tax is calculated based on net earnings for the period, adjusted for items that are non-taxable or taxed in different periods, using income tax rates that are substantively enacted at each reporting date.

Income taxes are recognized in net earnings or other comprehensive income, consistent with the items to which they relate.

(P) SHARE-BASED COMPENSATION

The Company's Stock Option Plan (the "Option Plan") provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered. The liability for awards granted to employees is initially measured based on the grant date fair value of the awards and the number of awards expected to vest. The awards are re-measured each reporting period for subsequent changes in the fair value of the liability. Fair value is determined using the Black-Scholes valuation model under a graded vesting method. Expected volatility is estimated based on historic results. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares under the Option Plan, consideration paid by the employee and any previously recognized liability associated with the stock options are recorded as share capital.

The Company grants Performance Share Units ("PSUs") to certain executive employees. The PSUs are subject to certain performance conditions and vest three years from original grant date.

The unamortized costs of employer contributions to the Company's share bonus program are included in other long-term assets.

(Q) FINANCIAL INSTRUMENTS

The Company classifies its financial instruments into one of the following categories: financial assets at amortized cost; financial liabilities at amortized cost; and fair value through profit or loss. All financial instruments are measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

Fair value through profit or loss financial instruments are subsequently measured at fair value with changes in fair value recognized in net earnings. All other categories of financial instruments are measured at amortized cost using the effective interest method.

Cash and cash equivalents, accounts receivable and certain other long-term assets are classified as financial assets at amortized cost since it is the Company's intention to hold these assets to maturity and the related cash flows are solely comprised of payments of principal and interest. Investments in publicly traded shares are classified as fair value through profit or loss. Accounts payable, accrued liabilities, certain other long-term liabilities, and long-term debt are classified as financial liabilities at amortized cost. Risk management assets and liabilities are classified as fair value through profit or loss.

Financial assets and liabilities are also categorized using a three-level hierarchy that reflects the significance of the inputs used in making fair value measurements for these assets and liabilities. The fair values of financial assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Fair values of financial assets and liabilities in Level 2 are based on inputs other than Level 1 quoted prices that are observable for the asset or liability either directly (as prices) or indirectly (derived from prices). The fair values of Level 3 financial assets and liabilities are not based on observable market data. The disclosure of the fair value hierarchy excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability.

Transaction costs in respect of financial instruments at fair value through profit or loss are recognized in net earnings. Transaction costs in respect of other financial instruments are included in the initial measurement of the financial instrument.

Impairment of financial assets

At each reporting date, on a forward looking basis, the Company assesses the expected credit losses associated with its financial assets carried at amortized cost. Expected credit losses are measured as the difference between the cash flows that are due to the Company and the cash flows that the Company expects to receive, discounted at the effective interest rate determined at initial recognition. For trade accounts receivable, the Company applies the simplified approach permitted by IFRS 9, which requires expected lifetime credit losses to be recognized from initial recognition of the receivables. To measure expected credit losses, accounts receivable are grouped based on the number of days the receivables have been outstanding and internal credit assessments of the customers. Credit risk for longer-term receivables is assessed based on an external credit rating of the counterparty. For longer-term receivables with credit risk that has not increased significantly since the date of recognition, the Company measures the expected credit loss as the 12-month expected credit loss.

Changes in the provision for expected credit loss are recognized in net earnings.

The Company continues to report impairment of financial assets for the years ended December 31, 2017 and 2016 in accordance with the Company's previous accounting policy for impairment of financial assets as follows:

At each reporting date, the Company assesses whether there is objective evidence that a financial asset is impaired. If such evidence exists, an impairment loss is recognized. Impairment losses on financial assets carried at amortized cost are calculated as the difference between the amortized cost of the financial asset and the present value of the estimated future cash flows, discounted using the instrument's original effective interest rate. Impairment losses on financial assets carried at amortized cost are reversed in subsequent periods if the amount of the loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized.

(R) RISK MANAGEMENT ACTIVITIES

The Company periodically uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized in the consolidated balance sheets at their estimated fair value. The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows, discount rates and credit risk. In determining these assumptions, the Company primarily relied on external, readily-observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The carrying amount of a risk management liability is adjusted for the Company's own credit risk.

The Company documents all derivative financial instruments that are formally designated as hedging transactions at the inception of the hedging relationship, in accordance with the Company's risk management policies. The effectiveness of the hedging relationship is evaluated, both at inception of the hedge and on an ongoing basis.

The Company periodically enters into commodity price contracts to manage anticipated sales and purchases of crude oil and natural gas in order to protect its cash flow for its capital expenditure programs. The effective portion of changes in the fair value of derivative commodity price contracts formally designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to risk management activities in net earnings in the same period or periods in which the commodity is sold or purchased. The ineffective portion of changes in the fair value of these designated contracts is recognized in risk management activities in net earnings. All changes in the fair value of non-designated crude oil and natural gas commodity price contracts are recognized in risk management activities in net earnings.

The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on certain of its long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. Changes in the fair value of interest rate swap contracts designated as fair value hedges and corresponding changes in the fair value of the hedged long-term debt are recognized in interest expense in net earnings. Changes in the fair value of non-designated interest rate swap contracts are recognized in risk management activities in net earnings.

Upon termination of an interest rate swap designated as a fair value hedge, the interest rate swap is derecognized in the consolidated balance sheets and the related long-term debt hedged is no longer revalued for subsequent changes in fair value due to interest rates changes. The fair value adjustment due to interest rates on the long-term debt at the date of termination of the interest rate swap is amortized to interest expense over the remaining term of the long-term debt.

Cross currency swap contracts are periodically used to manage currency exposure on US dollar denominated long-term debt. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. Changes in the fair value of the foreign exchange component of cross currency swap contracts designated as cash flow hedges related to the notional principal amounts are recognized in foreign exchange gains and losses in net earnings. The effective portion of changes in the fair value of the interest rate component of cross currency swap contracts designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to interest expense when the hedged item is recognized in net earnings, with the ineffective portion recognized in risk management activities in net earnings. Changes in the fair value of non-designated cross currency swap contracts are recognized in risk management activities in net earnings.

Realized gains or losses on the termination of financial instruments that have been designated as cash flow hedges are deferred under accumulated other comprehensive income and amortized into net earnings in the periods in which the underlying hedged items are recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized derivative gain or loss is recognized in net earnings. Realized gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in net earnings.

Foreign currency forward contracts are periodically used to manage foreign currency cash requirements. The foreign currency forward contracts involve the purchase or sale of an agreed upon amount of US dollars at a specified future date at forward exchange rates. Changes in the fair value of foreign currency forward contracts designated as cash flow hedges are initially recorded in other comprehensive income and are reclassified to foreign exchange gains and losses when the hedged item is recognized in net earnings. Changes in the fair value of non-designated foreign currency forward contracts are recognized in risk management activities in net earnings.

Embedded derivatives are derivatives that are included in a non-derivative host contract. Embedded derivatives are recorded at fair value separately from the host contract when their economic characteristics and risks are not clearly and closely related to the host contract, except when the host contract is an asset.

(S) COMPREHENSIVE INCOME

Comprehensive income is comprised of the Company's net earnings and other comprehensive income. Other comprehensive income includes the effective portion of changes in the fair value of derivative financial instruments designated as cash flow hedges and foreign currency translation gains and losses arising from the net investment in foreign operations that do not have a Canadian dollar functional currency. Other comprehensive income is shown net of related income taxes.

(T) PER COMMON SHARE AMOUNTS

The Company calculates basic earnings per common share by dividing net earnings by the weighted average number of common shares outstanding during the period. As the Company's Option Plan allows for the settlement of stock options in either cash or shares at the option of the holder, diluted earnings per common share is calculated using the more dilutive of cash settlement or share settlement under the treasury stock method.

(U) SHARE CAPITAL

Common shares are classified as equity. Costs directly attributable to the issue of new shares or options are included in equity as a deduction from proceeds, net of tax. When the Company acquires its own common shares, share capital is reduced by the average carrying value of the shares purchased. The excess of the purchase price over the average carrying value is recognized as a reduction of retained earnings. Shares are cancelled upon purchase.

(V) DIVIDENDS

Dividends on common shares are recognized in the Company's financial statements in the period in which the dividends are declared by the Board of Directors.

2. Changes in Accounting Policies

IFRS 15 "REVENUE FROM CONTRACTS WITH CUSTOMERS"

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers" to provide guidance on the recognition of revenue and cash flows arising from an entity's contracts with customers, and related disclosures. The new standard replaces several existing standards related to recognition of revenue and states that revenue should be recognized as performance obligations related to the goods or services delivered are settled. IFRS 15 also provides revenue accounting guidance for contract modifications and multiple-element contracts and prescribes additional disclosure requirements.

The Company adopted IFRS 15 on January 1, 2018 using the retrospective with cumulative effect method. There were no changes to reported net earnings or retained earnings as a result of adopting IFRS 15. Under the standard, the Company is required to provide additional disclosure of disaggregated revenue by major product type. In connection with adoption of the standard, the Company has reclassified certain comparative amounts in a manner consistent with the presentation adopted for the year ended December 31, 2018 (see note 22).

Upon adoption of IFRS 15, the Company applied the practical expedient such that contracts that were completed in the comparative periods have not been restated. Applying this expedient had no impact to the revenue recognized under the previous revenue accounting standard as all performance obligations had been met and the consideration had been determined.

IFRS 9 "FINANCIAL INSTRUMENTS"

Effective January 1, 2014, the Company adopted the version of IFRS 9 "Financial Instruments" issued November 2013. In July 2014, the IASB issued amendments to IFRS 9 to include accounting guidance to assess and recognize impairment losses on financial assets based on an expected loss model.

The Company retrospectively adopted the amendments to IFRS 9 on January 1, 2018 and elected to apply the limited exemption in IFRS 9 relating to transition for impairment. Accordingly, provisions for impairment have not been restated in the comparative periods. Adoption of the amendment did not have a significant impact on the Company's previous accounting for impairment of financial assets.

3. Accounting Standards Issued But Not Yet Applied

In October 2018, the IASB issued amendments to IFRS 3 "Definition of a Business" that narrowed and clarified the definition of a business. The amendments also permit a simplified assessment of whether an acquired set of activities and assets is a group of assets rather than a business. The amendments are effective January 1, 2020 with earlier adoption permitted. The amendments apply to business combinations after the date of adoption. The Company is assessing the impact of these amendments on its consolidated financial statements.

In October 2018, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" and IAS 8 "Accounting Policies, Changes in Accounting Estimates and Errors". The amendments make minor changes to the definition of the term "material" and align the definition across all IFRS Standards. Materiality is used in making judgments related to the preparation of financial statements. The amendments are effective January 1, 2020 with earlier adoption permitted. The Company is assessing the impact of these amendments on its consolidated financial statements.

In October 2017, the IASB issued amendments to IAS 28 "Investments in Associates and Joint Ventures" to clarify that the impairment provisions in IFRS 9 apply to financial instruments in an associate or joint venture that are not accounted for using the equity method, including long-term assets that form part of the net investment in the associate or joint venture. The amendments are effective January 1, 2019 with earlier adoption permitted. The amendments are required to be adopted retrospectively. The Company has determined that these amendments have no significant impact on its consolidated financial statements.

In June 2017, the IASB issued IFRIC 23 "Uncertainty over Income Tax Treatments". The interpretation provides guidance on how to reflect the effects of uncertainty in accounting for income taxes where IAS 12 is unclear. The interpretation is effective January 1, 2019. The Company has determined that this interpretation has no significant impact on its consolidated financial statements.

IFRS 16 "LEASES"

In January 2016, the IASB issued IFRS 16 "Leases", which provides guidance on accounting for leases. The new standard replaces IAS 17 "Leases" and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees and requires balance sheet recognition for all leases. Certain short-term (less than 12 months) and low-value leases (as defined in the standard) are exempt from the requirements, and may continue to be treated as an expense. Leases to explore for or use crude oil, natural gas, minerals and similar non-regenerative resources are exempt from the standard.

The Company will adopt IFRS 16 on January 1, 2019 using the retrospective with cumulative effect method with no impact to opening retained earnings at the date of adoption. In accordance with the transitional provisions in the standard, balances reported in the comparative periods will not be restated.

On initial adoption, the Company intends to use the following practical expedients under the standard. Certain expedients are on a lease-by-lease basis and others are applicable by class of underlying assets:

- the use of a single discount rate to a portfolio of leases with reasonably similar characteristics;
- leases with a remaining lease term of less than twelve months as at January 1, 2019 will be treated as short-term leases; and
- exclusion of indirect costs for the measurement of lease assets at the date of initial application.

The Company does not intend to apply any practical expedients pertaining to grandfathering of leases assessed under the previous standard.

On adoption of IFRS 16, the Company will recognize lease assets and liabilities at the present value of the remaining lease payments, discounted using the Company's applicable borrowing rate on January 1, 2019. The Company expects to report additional lease assets and corresponding liabilities of between $1.5 billion and $1.6 billion. The Company continues to finalize its accounting for leases in accordance with IFRS 16, and the above estimates are subject to change based on finalization of the Company's review of its lease arrangements.

In the statement of earnings, depletion, depreciation and amortization expense and interest expense will increase, with corresponding decreases in production, transportation and administration expenses. The Company does not expect to report a material impact on net earnings. Under the new standard, the Company will report cash outflows for repayment of the principal portion of the lease liability as cash flows from financing activities. The interest portion of the lease payments will continue to be classified as cash flows from operating activities.

Where the Company, acting as the operator, signs a lease on behalf of a joint operation and assumes the legal liability for that lease, the Company will recognize 100% of the related lease asset and lease liability. As the Company recovers its joint operation partners' share of the costs of the lease contract, these recoveries will be recognized in the consolidated statements of earnings.

4. Critical Accounting Estimates and Judgements

The Company has made estimates, assumptions and judgements regarding certain assets, liabilities, revenues and expenses in the preparation of the consolidated financial statements, primarily related to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts. The estimates, assumptions and judgements that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are addressed below.

(A) CRUDE OIL AND NATURAL GAS RESERVES

Purchase price allocations, depletion, depreciation and amortization, asset retirement obligations, and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves. Reserves estimates are based on engineering data, estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures, all of which are subject to many uncertainties, interpretations and judgements. The Company expects that, over time, its reserves estimates will be revised upward or downward based on updated information.

(B) ASSET RETIREMENT OBLIGATIONS

The Company provides for asset retirement obligations on its property, plant and equipment based on current legislation and operating practices. Estimated future costs include assumptions of dates of future abandonment and technological advances and estimates of future inflation rates and discount rates. Actual costs may vary from the estimated provision due to changes in environmental legislation, the impact of inflation, changes in technology, changes in operating practices, and changes in the date of abandonment due to changes in reserves life. These differences may have a material impact on the estimated provision.

(C) INCOME TAXES

The Company is subject to income taxes in numerous legal jurisdictions. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes a liability for a tax filing position based on its assessment of the probability that additional taxes may ultimately be due.

(D) FAIR VALUE OF DERIVATIVES AND OTHER FINANCIAL INSTRUMENTS

The fair value of financial instruments that are not traded in an active market is determined using valuation techniques. The Company uses its judgement to select a variety of methods and make assumptions that are primarily based on market conditions existing at the end of each reporting period. The Company uses directly and indirectly observable inputs in measuring the value of financial instruments that are not traded in active markets, including quoted commodity prices and volatility, interest rate yield curves and foreign exchange rates.

(E) PURCHASE PRICE ALLOCATIONS

Purchase prices related to business combinations are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make estimates, assumptions and judgements regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of crude oil and natural gas properties together with deferred income tax effects. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future depletion, depreciation, and amortization expense and impairment tests.

(F) SHARE-BASED COMPENSATION

The Company has made various assumptions in estimating the fair values of stock options granted under its Option Plan, including expected volatility, expected exercise timing and future forfeiture rates. At each period end, stock options outstanding are remeasured for changes in the estimated fair value of the liability.

(G) IDENTIFICATION OF CGUs

CGUs are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The classification of assets into CGUs requires significant judgement and interpretations with respect to the integration between assets, the existence of active markets, shared infrastructures, and the way in which management monitors the Company's operations.

(H) IMPAIRMENT OF ASSETS

The recoverable amount of a CGU or an individual asset has been determined as the higher of the CGUs' or the asset's fair value less costs of disposal and its value in use. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available, including information on future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and operating costs, after-tax discount rates currently ranging from 10% to 12%, and income taxes. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

(I) CONTINGENCIES

Contingencies are subject to measurement uncertainty as the related financial impact will only be confirmed by the outcome of a future event. The assessment of contingencies requires the application of judgements and estimates including the determination of whether a present obligation exists and the reliable estimation of the timing and amount of cash flows required to settle the contingency.

5. Inventory

	2018	2017
Product inventory	**$ 297**	$ 285
Materials and supplies	**658**	609
	$ 955	$ 894

The Company recorded a write-down of its product inventory of $13 million from cost to net realizable value as at December 31, 2018 (2017 – $33 million).

6. Exploration and Evaluation Assets

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2016	$ 2,306	$ –	$ 76	$ –	$ 2,382
Additions	144	–	15	–	159
Acquisition of AOSP and other assets (note 8)	31	–	–	259	290
Transfers to property, plant and equipment	(198)	–	–	–	(198)
Disposals/derecognitions	(1)	–	–	–	(1)
At December 31, 2017	2,282	–	91	259	2,632
Additions	**245**	–	**35**	**222**	**502**
Transfers to property, plant and equipment	**(175)**	–	–	**(222)**	**(397)**
Disposals/derecognitions and other	**(4)**	–	**(89)**	**(7)**	**(100)**
At December 31, 2018	**$ 2,348**	**$** –	**$ 37**	**$ 252**	**$ 2,637**

During the year ended December 31, 2018, the Company acquired a number of exploration and evaluation properties in the Oil Sands Mining and Upgrading and North America Exploration and Production segments.

In the Oil Sands Mining and Upgrading segment, the Company acquired the Joslyn oil sands project including exploration and evaluation assets of $222 million and associated asset retirement obligations of $4 million. Total consideration of $218 million was comprised of $100 million cash on closing with the remaining balance paid equally over each of the next five years. In the fourth quarter of 2018, following integration of the acquired assets into the Horizon mine plan and determination of proved crude oil reserves, the exploration and evaluation assets were transferred to property, plant and equipment. The above amounts are estimates, and may be subject to change based on the receipt of new information.

In the North America Exploration and Production segment, the Company acquired Laricina Energy Ltd., including exploration and evaluation assets of $118 million and property, plant and equipment of $44 million. In addition, the Company also acquired cash of $24 million and deferred income tax assets of $168 million and assumed net working capital liabilities of $18 million, asset retirement obligations of $17 million and notes payable of $48 million. Total purchase consideration was $46 million, resulting in a pre-tax gain of $225 million on the acquisition, representing the excess of the fair value of the net assets acquired compared to total purchase consideration. The Company settled the notes payable immediately following the completion of the acquisition. The transaction was accounted for using the acquisition method of accounting. The above amounts are estimates, and may be subject to change based on the receipt of new information.

The Company also completed two additional farm-out agreements in the Offshore Africa segment to dispose of a combined 30% interest in its exploration right in South Africa, comprised of exploration and evaluation assets of $89 million, including a recovery of $14 million of past incurred costs, for net proceeds of $105 million (US$79 million), resulting in a pre-tax gain of $16 million ($12 million after-tax). The Company retains a 20% working interest in the exploration right following the completion of these farm-out agreements.

Under the terms of the various agreements, in the event of a commercial crude oil discovery on the exploration right and conversion to a production right, additional cash payments of between US$623 million and US$645 million will be made to the Company. In the event of a commercial natural gas discovery on the exploration right and conversion to a production right, additional cash payments of between US$126 million and US$132 million will be made to the Company.

During 2017, the Company also disposed of a number of North America exploration and evaluation assets with a net book value of $1 million for consideration of $36 million, resulting in a pre-tax gain on sale of properties of $35 million.

7. Property, Plant and Equipment

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2016	$ 61,647	$ 7,380	$ 5,132	$ 27,038	$ 234	$ 395	$ 101,826
Additions [(1)]	3,003	255	101	1,660	194	19	5,232
Acquisition of AOSP and other assets (note 8)	349	–	–	13,832	–	–	14,181
Transfers from E&E assets	198	–	–	–	–	–	198
Disposals/derecognitions	(381)	–	–	(446)	–	–	(827)
Foreign exchange adjustments and other	–	(509)	(352)	–	–	–	(861)
At December 31, 2017	64,816	7,126	4,881	42,084	428	414	119,749
Additions [(2)]	**2,428**	**237**	**212**	**1,050**	**13**	**21**	**3,961**
Transfers from E&E assets	**175**	**–**	**–**	**222**	**–**	**–**	**397**
Disposals/derecognitions	**(412)**	**(703)**	**(70)**	**(209)**	**–**	**–**	**(1,394)**
Foreign exchange adjustments and other	**–**	**661**	**448**	**–**	**–**	**–**	**1,109**
At December 31, 2018	**$ 67,007**	**$ 7,321**	**$ 5,471**	**$ 43,147**	**$ 441**	**$ 435**	**$ 123,822**
Accumulated depletion and depreciation							
At December 31, 2016	$ 38,311	$ 5,584	$ 3,797	$ 2,828	$ 115	$ 281	$ 50,916
Expense	3,220	509	205	1,220	9	23	5,186
Disposals/derecognitions	(381)	–	–	(446)	–	–	(827)
Foreign exchange adjustments and other	1	(440)	(283)	26	–	–	(696)
At December 31, 2017	41,151	5,653	3,719	3,628	124	304	54,579
Expense	**3,111**	**257**	**201**	**1,557**	**14**	**21**	**5,161**
Disposals/derecognitions	**(393)**	**(703)**	**(70)**	**(209)**	**–**	**–**	**(1,375)**
Foreign exchange adjustments and other	**12**	**528**	**353**	**5**	**–**	**–**	**898**
At December 31, 2018	**$ 43,881**	**$ 5,735**	**$ 4,203**	**$ 4,981**	**$ 138**	**$ 325**	**$ 59,263**
Net book value							
– at December 31, 2018	**$ 23,126**	**$ 1,586**	**$ 1,268**	**$ 38,166**	**$ 303**	**$ 110**	**$ 64,559**
– at December 31, 2017	$ 23,665	$ 1,473	$ 1,162	$ 38,456	$ 304	$ 110	$ 65,170

(1) Additions in Midstream include a pre-tax revaluation gain of $114 million of a previously held joint interest in certain pipeline system assets.
(2) Additions in North Sea include a pre-tax revaluation gain of $19 million relating to acquisitions of its previously held interest.

Project costs not subject to depletion and depreciation	2018	2017
Kirby Thermal Oil Sands – North	**$ 1,424**	$ 944

During the year ended December 31, 2018, the Company acquired a number of producing crude oil and natural gas properties in the North America and North Sea Exploration and Production segments. These transactions were accounted for using the acquisition method of accounting. Gains reported on the acquisitions represent the excess of the fair value of the net assets acquired compared to total purchase consideration.

In North America Exploration and Production, excluding the impact of acquisitions disclosed in note 6, the Company acquired property, plant and equipment for net cash consideration paid of $170 million and assumed associated asset retirement obligations of $13 million. No net deferred income tax liabilities were recognized. The Company recognized a pre-tax gain of $47 million on the transactions.

In connection with the acquisition of the remaining interest in certain operations in the North Sea Exploration and Production segment, the Company acquired $108 million of property, plant and equipment, for net proceeds received of $73 million. The Company also acquired net working capital of $7 million, assumed associated asset retirement obligations of $41 million and recognized net deferred income tax liabilities of $27 million. The Company recognized a pre-tax gain of $120 million on the acquisition and a pre-tax revaluation gain of $19 million relating to its previously held interest.

During the fourth quarter of 2018, the Gabonese Republic agreed to cessation of production from the Company's Olowi field, as well as the terms of termination of the Olowi Production Sharing Contract and the return of the permit area back to the Gabonese Republic, including the associated asset retirement obligations of $69 million. The transaction resulted in a pre-tax gain on disposition of property of $20 million ($14 million after-tax).

During 2017, the Company acquired a number of other producing crude oil and natural gas properties in the North America Exploration and Production segment, including exploration and evaluation assets of $27 million (2016 – $nil), for net cash consideration of $1,013 million (2016 – $159 million). These transactions were accounted for using the acquisition method of accounting. In connection with these acquisitions, the Company assumed associated asset retirement obligations of $63 million (2016 – $30 million). No net deferred income tax liabilities were recognized on these acquisitions (2016 – $nil).

In connection with the acquisition of pipeline system assets in the Midstream segment in 2017, the Company recognized a pre-tax revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in the pipeline.

As at December 31, 2018, the Company assessed the recoverability of its property, plant and equipment and its exploration and evaluation assets, and determined the carrying amounts to be recoverable.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once the asset is substantially available for its intended use. During 2018, pre-tax interest of $69 million (2017 – $82 million; 2016 – $233 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.9% (2017 – 3.8%; 2016 – 3.9%).

8. Acquisition of Interests in the Athabasca Oil Sands Project and Other Assets

On May 31, 2017, the Company completed the acquisition of a direct and indirect 70% interest in AOSP from Shell Canada Limited and certain subsidiaries ("Shell") and an affiliate of Marathon Oil Corporation ("Marathon"), including a 70% interest in the mining and extraction operations north of Fort McMurray, Alberta, 70% of the Scotford Upgrader and Quest Carbon Capture and Storage ("CCS") project, and a 100% working interest in the Peace River thermal in situ operations and Cliffdale heavy oil field, as well as other oil sands leases. The Company also assumed certain pipeline and other commitments (see note 20). The Company consolidates its direct and indirect interest in the assets, liabilities, revenue and expenses of AOSP and other assets in proportion to the Company's interests.

Total purchase consideration of $12,541 million was comprised of cash payments of $8,217 million, approximately 97.6 million common shares of the Company issued to Shell with a fair value of approximately $3,818 million, and deferred purchase consideration of $506 million (US$375 million) paid to Marathon in March 2018. The fair value of the Company's common shares was determined using the market price of the shares as at the acquisition date.

In connection with the acquisition of AOSP and other assets, the Company arranged acquisition financing of $1.8 billion of medium-term notes in Canada, US$3 billion of long-term notes in the United States and a $3 billion non-revolving term loan facility (see note 11).

The acquisition has been accounted for as a business combination using the acquisition method of accounting. The allocation of the purchase price was based on management's best estimates of the fair value of the assets and liabilities acquired as at the acquisition date.

The following provides a summary of the net assets acquired and (liabilities) assumed relating to the acquisition:

Cash	**$**	**93**
Other working capital		**291**
Property, plant and equipment		**14,181**
Exploration and evaluation assets		**290**
Asset retirement obligations		**(721)**
Other long-term liabilities		**(73)**
Deferred income taxes		**(1,287)**
Net assets acquired	**$**	**12,774**
Total purchase consideration		**12,541**
Gain on acquisition before transaction costs	**$**	**233**

For the year ended December 31, 2017, the Company recognized a gain of $230 million, net of transaction costs of $3 million, representing the excess of the fair value of the net assets acquired compared to total purchase consideration.

9. Investments

As at December 31, 2018 and 2017, the Company had the following investments:

		2018		2017
Investment in PrairieSky Royalty Ltd.	**$**	**400**	$	726
Investment in Inter Pipeline Ltd.		**124**		167
	$	**524**	$	893

INVESTMENT IN PRAIRIESKY ROYALTY LTD.

The Company's investment of 22.6 million common shares does not constitute significant influence, and is accounted for at fair value through profit or loss, remeasured at each reporting date. As at December 31, 2018, the Company's investment in PrairieSky Ltd. ("PrairieSky") was classified as a current asset. PrairieSky is in the business of acquiring and managing oil and gas royalty income assets through indirect third-party oil and gas development.

The loss (gain) from the investment in PrairieSky was comprised as follows:

		2018		2017		2016
Fair value loss (gain) from PrairieSky	**$**	**326**	$	(3)	$	(292)
Dividend income from PrairieSky		**(17)**		(17)		(27)
	$	**309**	$	(20)	$	(319)

INVESTMENT IN INTER PIPELINE LTD.

During 2016, as partial consideration for the disposal of the Company's interest in the Cold Lake Pipeline, the Company received non-cash share consideration of $190 million, comprised of approximately 6.4 million common shares of Inter Pipeline at $29.57 per common share determined as of the closing date. Inter Pipeline is in the business of petroleum transportation, natural gas liquids processing, and bulk liquid storage in Western Canada and Europe.

The Company's investment of 6.4 million common shares of Inter Pipeline does not constitute significant influence, and is accounted for at fair value through profit or loss, remeasured at each reporting date. As at December 31, 2018, the Company's investment in Inter Pipeline was classified as a current asset.

The loss (gain) from the investment in Inter Pipeline was comprised as follows:

		2018		2017		2016
Fair value loss from Inter Pipeline	**$**	**43**	$	23	$	–
Dividend income from Inter Pipeline		**(11)**		(10)		(1)
	$	**32**	$	13	$	(1)

10. Other Long-Term Assets

	2018	2017
Investment in North West Redwater Partnership	$ 287	$ 292
North West Redwater Partnership subordinated debt [1]	591	510
Risk management (note 19)	373	204
Other	208	241
	1,459	1,247
Less: current portion	116	79
	$ 1,343	$ 1,168

(1) Includes accrued interest.

INVESTMENT IN NORTH WEST REDWATER PARTNERSHIP

The Company's 50% interest in Redwater Partnership is accounted for using the equity method based on Redwater Partnership's voting and decision-making structure and legal form. Redwater Partnership has entered into agreements to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement.

The facility capital cost ("FCC") budget for the Project is currently estimated to be $9,700 million. The Project is currently in the commissioning phase. During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to reflect an agreed debt to equity ratio of 80/20. To December 31, 2018, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $152 million, for a Company total of $591 million. Any additional subordinated debt financing is not expected to be significant.

Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service toll, currently consisting of interest and fees, with principal repayments beginning in 2020 (see note 20). The Company is unconditionally obligated to pay this portion of the cost of service toll over the 30-year tolling period. As at December 31, 2018, the Company had recognized $62 million in prepaid service tolls.

As at December 31, 2018, Redwater Partnership had borrowings of $2,333 million under its secured $3,500 million syndicated credit facility, maturing June 2018. During the first quarter of 2018, Redwater Partnership extended $2,000 million of the $3,500 revolving syndicated credit facility to June 2021. The remaining $1,500 million was extended on a fully drawn non-revolving basis maturing February 2020.

During 2017, Redwater Partnership issued $750 million of 2.80% series J senior secured bonds due June 2027 and $750 million of 3.65% series K senior secured bonds due June 2035.

The assets, liabilities, partners' equity and equity loss (income) related to Redwater Partnership and the Company's 50% interest at December 31, 2018 and 2017 were comprised as follows:

	2018		2017	
	Redwater Partnership 100% interest	Company 50% interest	Redwater Partnership 100% interest	Company 50% interest
Current assets	$ 210	$ 105	$ 330	$ 165
Non-current assets	$ 11,250	$ 5,625	$ 10,540	$ 5,270
Current liabilities	$ 352	$ 176	$ 2,476	$ 1,238
Non-current liabilities	$ 10,534	$ 5,267	$ 7,810	$ 3,905
Partners' equity	$ 574	$ 287	$ 584	$ 292
Equity loss (income)	$ 10	$ 5	$ (62)	$ (31)

11. Long-Term Debt

		2018		2017
Canadian dollar denominated debt, unsecured				
Bank credit facilities	**$**	**831**	$	3,544
Medium-term notes				
3.05% debentures due June 19, 2019		**500**		500
2.60% debentures due December 3, 2019		**500**		500
2.05% debentures due June 1, 2020		**900**		900
2.89% debentures due August 14, 2020		**1,000**		1,000
3.31% debentures due February 11, 2022		**1,000**		1,000
3.55% debentures due June 3, 2024		**500**		500
3.42% debentures due December 1, 2026		**600**		600
4.85% debentures due May 30, 2047		**300**		300
		6,131		8,844
US dollar denominated debt, unsecured				
Bank credit facilities (December 31, 2018 – US$2,954 million; December 31, 2017 – US$1,839 million)		**4,031**		2,300
Commercial paper (December 31, 2018 – US$104 million; December 31, 2017 – US$500 million)		**141**		625
US dollar debt securities				
1.75% due January 15, 2018 (US$600 million)		**–**		751
5.90% due February 1, 2018 (US$400 million)		**–**		501
3.45% due November 15, 2021 (US$500 million)		**682**		625
2.95% due January 15, 2023 (US$1,000 million)		**1,364**		1,252
3.80% due April 15, 2024 (US$500 million)		**682**		625
3.90% due February 1, 2025 (US$600 million)		**819**		751
3.85% due June 1, 2027 (US$1,250 million)		**1,706**		1,566
7.20% due January 15, 2032 (US$400 million)		**546**		501
6.45% due June 30, 2033 (US$350 million)		**478**		438
5.85% due February 1, 2035 (US$350 million)		**478**		438
6.50% due February 15, 2037 (US$450 million)		**614**		563
6.25% due March 15, 2038 (US$1,100 million)		**1,501**		1,377
6.75% due February 1, 2039 (US$400 million)		**546**		501
4.95% due June 1, 2047 (US$750 million)		**1,023**		939
		14,611		13,753
Long-term debt before transaction costs and original issue discounts, net		**20,742**		22,597
Less: original issue discounts, net (1)		**17**		18
transaction costs (1) (2)		**102**		121
		20,623		22,458
Less: current portion of commercial paper		**141**		625
current portion of long-term debt (1) (2)		**1,000**		1,252
	$	**19,482**	$	20,581

(1) The Company has included unamortized original issue discounts and premiums, and directly attributable transaction costs in the carrying amount of the outstanding debt.
(2) Transaction costs primarily represent underwriting commissions charged as a percentage of the related debt offerings, as well as legal, rating agency and other professional fees.

BANK CREDIT FACILITIES AND COMMERCIAL PAPER

As at December 31, 2018, the Company had in place revolving bank credit facilities of $4,976 million of which $4,723 million was available for use. Additionally, the Company had in place fully drawn term credit facilities of $4,750 million. Details of these facilities are described below. This excludes certain other dedicated credit facilities supporting letters of credit.

- a $100 million demand credit facility;
- a $1,800 million non-revolving term credit facility maturing May 2020;
- a $2,200 million non-revolving term credit facility maturing October 2020;
- a $750 million non-revolving term credit facility maturing February 2021;
- a $2,425 million revolving syndicated credit facility with $330 million maturing in June 2019 and $2,095 million maturing June 2021;
- a $2,425 million revolving syndicated credit facility maturing June 2022; and
- a £15 million demand credit facility related to the Company's North Sea operations.

During 2018, the Company extended the $2,425 million revolving syndicated credit facility originally due June 2020 to June 2022. Each of the $2,425 million revolving facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal is repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.

During 2018, the Company repaid and cancelled $1,200 million of the $3,000 million non-revolving term credit facility (third quarter of 2018 – $1,050 million; first quarter of 2018 – $150 million) scheduled to mature in May 2020. The required annual amortization of 5% of the original balance is now satisfied. Borrowings under the term loan facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2018, the $1,800 million facility was fully drawn.

During 2018, the Company extended the $2,200 million non-revolving credit facility originally due October 2019 to October 2020. Borrowings under the $2,200 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2018, the $2,200 million facility was fully drawn.

During 2018, the Company repaid and cancelled the $125 million non-revolving term credit facility scheduled to mature in February 2019. The Company also extended the $750 million non-revolving term credit facility originally due February 2019 to February 2021. Borrowings under the $750 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2018, the $750 million facility was fully drawn.

The Company's borrowings under its US commercial paper program are authorized up to a maximum US$2,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at December 31, 2018 was 2.6% (December 31, 2017 – 2.2%), and on total long-term debt outstanding for the year ended December 31, 2018 was 3.9% (December 31, 2017 – 3.8%).

As at December 31, 2018, letters of credit and guarantees aggregating to $450 million were outstanding.

MEDIUM-TERM NOTES

During 2017, the Company issued $900 million of 2.05% medium-term notes due June 2020, $600 million of 3.42% medium-term notes due December 2026 and $300 million of 4.85% medium-term notes due May 2047. Proceeds from the securities were used to finance the acquisition of AOSP and other assets. In July 2017, the Company filed a new base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

US DOLLAR DEBT SECURITIES

During 2018, the Company repaid US$600 million of 1.75% notes and US$400 million of 5.90% notes.

During 2017, the Company repaid US$1,100 million of 5.70% notes, and issued US$1,000 million of 2.95% notes due January 2023, US$1,250 million of 3.85% notes due June 2027 and US$750 million of 4.95% notes due June 2047. Proceeds from the debt securities were used to finance the acquisition of AOSP and other assets. In July 2017, the Company filed a new base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

SCHEDULED DEBT REPAYMENTS

Scheduled debt repayments are as follows:

Year		Repayment
2019	$	1,141
2020	$	5,996
2021	$	1,444
2022	$	1,003
2023	$	1,365
Thereafter	$	9,793

12. Other Long-Term Liabilities

		2018		2017
Asset retirement obligations	**$**	**3,886**	$	4,327
Share-based compensation		**124**		414
Risk management (note 19)		**17**		103
Deferred purchase consideration (1) (2)		**118**		469
Other		**80**		96
		4,225		5,409
Less: current portion		**335**		1,012
	$	**3,890**	$	4,397

(1) Includes $118 million of deferred purchase consideration at December 31, 2018, payable in annual installments of $25 million over the next five years.
(2) Includes $469 million (US$375 million) of deferred purchase consideration at December 31, 2017, paid to Marathon in March 2018.

ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 5.0% (2017 – 4.7%; 2016 – 5.2%) and inflation rates of up to 2% (December 31, 2017 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

		2018		2017		2016
Balance – beginning of year	**$**	**4,327**	$	3,243	$	2,950
Liabilities incurred		**19**		12		3
Liabilities acquired, net		**6**		784		30
Liabilities settled		**(290)**		(274)		(267)
Asset retirement obligation accretion		**186**		164		142
Revision of cost, inflation rates and timing estimates		**(111)**		(40)		(68)
Change in discount rate		**(334)**		509		493
Foreign exchange adjustments		**83**		(71)		(40)
Balance – end of year		**3,886**		4,327		3,243
Less: current portion		**186**		92		95
	$	**3,700**	$	4,235	$	3,148

Segmented Asset Retirement Obligations

		2018		2017
Exploration and Production				
North America	**$**	**1,665**	$	1,840
North Sea		**707**		755
Offshore Africa		**134**		245
Oil Sands Mining and Upgrading		**1,379**		1,486
Midstream		**1**		1
	$	**3,886**	$	4,327

SHARE-BASED COMPENSATION

As the Company's Option Plan provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered, a liability for potential cash settlements is recognized. The current portion represents the maximum amount of the liability payable within the next twelve month period if all vested stock options are surrendered for cash settlement.

		2018		2017		2016
Balance – beginning of year	**$**	**414**	$	426	$	128
Share-based compensation (recovery) expense		**(146)**		134		355
Cash payment for stock options surrendered		**(5)**		(6)		(7)
Transferred to common shares		**(120)**		(154)		(117)
(Recovered from) charged to Oil Sands Mining and Upgrading, net		**(19)**		14		67
Balance – end of year		**124**		414		426
Less: current portion		**92**		348		368
	$	**32**	$	66	$	58

Included within share-based compensation liability as at December 31, 2018 was $13 million (2017 – $5 million; 2016 – $nil) related to performance share units granted to certain executive employees.

The fair value of stock options outstanding was estimated using the Black-Scholes valuation model with the following weighted average assumptions:

		2018		2017		2016
Fair value	**$**	**3.33**	$	11.82	$	11.41
Share price	**$**	**32.94**	$	44.92	$	42.79
Expected volatility		**27.4%**		27.1%		30.7%
Expected dividend yield		**4.1%**		2.5%		2.3%
Risk free interest rate		**1.9%**		1.8%		0.9%
Expected forfeiture rate		**4.2%**		5.0%		5.0%
Expected stock option life (1)		**4.4 years**		4.5 years		4.6 years

(1) At original time of grant.

The intrinsic value of vested stock options at December 31, 2018 was $27 million (2017 – $195 million; 2016 – $191 million).

13. Income Taxes

The provision for income tax was as follows:

Expense (recovery)		2018		2017		2016
Current corporate income tax – North America	**$**	**312**	$	(145)	$	(377)
Current corporate income tax – North Sea		**28**		57		(74)
Current corporate income tax – Offshore Africa		**54**		45		22
Current PRT (1) – North Sea		**(29)**		(132)		(198)
Other taxes		**9**		11		9
Current income tax		**374**		(164)		(618)
Deferred corporate income tax		**540**		586		(106)
Deferred PRT (1) – North Sea		**17**		54		(135)
Deferred income tax		**557**		640		(241)
Income tax	**$**	**931**	$	476	$	(859)

(1) Petroleum Revenue Tax.

The provision for income tax is different from the amount computed by applying the combined statutory Canadian federal and provincial income tax rates to earnings (loss) before taxes. The reasons for the difference are as follows:

		2018		2017		2016
Canadian statutory income tax rate		**27.0%**		27.0%		27.0%
Income tax provision at statutory rate	**$**	**951**	$	776	$	(287)
Effect on income taxes of:						
UK PRT and other taxes		**(3)**		(67)		(324)
Impact of deductible UK PRT and other taxes on corporate income tax		**3**		28		131
Foreign and domestic tax rate differentials		**6**		(43)		(54)
Non-taxable portion of capital gains/losses		**142**		(86)		(80)
Stock options exercised for common shares		**(41)**		33		94
Income tax rate and other legislative changes		**–**		10		(107)
Non-taxable gain on corporate acquisitions		**(119)**		(63)		–
Revisions arising from prior year tax filings		**(136)**		(3)		(120)
Change in unrecognized capital loss carryforward asset		**142**		(86)		(80)
Other		**(14)**		(23)		(32)
Income tax expense (recovery)	**$**	**931**	$	476	$	(859)

The following table summarizes the temporary differences that give rise to the net deferred income tax liability:

		2018		2017
Deferred income tax liabilities				
Property, plant and equipment and exploration and evaluation assets	**$**	**12,885**	$	12,484
Unrealized risk management activities		**33**		20
PRT deduction for corporate income tax		**1**		7
Investments		**46**		96
Investment in North West Redwater Partnership		**414**		252
Other		**174**		–
		13,553		12,859
Deferred income tax assets				
Asset retirement obligations		**(1,142)**		(1,264)
Loss carryforwards		**(855)**		(523)
Unrealized foreign exchange loss on long-term debt		**(104)**		(29)
Deferred PRT		**(1)**		(18)
Other		**–**		(50)
		(2,102)		(1,884)
Net deferred income tax liability	**$**	**11,451**	$	10,975

Movements in deferred tax assets and liabilities recognized in net earnings (loss) during the year were as follows:

		2018		2017		2016
Property, plant and equipment and exploration and evaluation assets	**$**	**281**	$	541	$	37
Timing of partnership items		**–**		–		(261)
Unrealized foreign exchange (gain) loss on long-term debt		**(75)**		120		63
Unrealized risk management activities		**18**		(46)		(44)
Asset retirement obligations		**175**		(88)		(20)
Loss carryforwards		**(61)**		48		(221)
Investments		**(50)**		(2)		38
Investment in North West Redwater Partnership		**162**		30		81
Deferred PRT		**17**		54		(135)
PRT deduction for corporate income tax		**(7)**		(21)		61
Other		**97**		4		160
	$	**557**	$	640	$	(241)

The following table summarizes the movements of the net deferred income tax liability during the year:

	2018	2017	2016
Balance – beginning of year	**$ 10,975**	$ 9,073	$ 9,344
Deferred income tax expense (recovery)	**557**	640	(241)
Deferred income tax (recovery) expense included in other comprehensive income	**(6)**	4	(5)
Foreign exchange adjustments	**41**	(29)	(25)
Business combinations (note 6, 7, 8)	**(116)**	1,287	–
Balance – end of year	**$ 11,451**	$ 10,975	$ 9,073

Current income taxes recognized in each operating segment will vary depending upon available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

During 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by $10 million.

During 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of $107 million. In addition, the UK government also enacted legislation to reduce the PRT rate from 35% to 0% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to 2015 and prior taxation years for PRT purposes are still recoverable at a PRT rate of 50%. As a result of these tax changes, the Company's deferred PRT liability was reduced by $228 million and the deferred corporate income tax liability was increased by $114 million.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's reported results of operations, financial position or liquidity.

Deferred income tax assets are recognized for temporary differences to the extent that the realization of the related tax benefit through future taxable profits is probable. The Company has not recognized deferred income tax assets with respect to taxable capital loss carryforwards in excess of $1,000 million in North America, which can be carried forward indefinitely and only applied against future taxable capital gains. In addition, the Company has not recognized deferred income tax assets related to North American tax pools of approximately $750 million, which can only be claimed against income from certain oil and gas properties.

Deferred income tax liabilities have not been recognized on the unremitted net earnings of wholly controlled subsidiaries. The Company is able to control the timing and amount of distributions and no taxes are payable on distributions from these subsidiaries provided that the distributions remain within certain limits.

14. Share Capital

AUTHORIZED

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	2018		2017	
Issued Common shares	**Number of shares** (thousands)	**Amount**	Number of shares (thousands)	Amount
Balance – beginning of year	**1,222,769**	**$ 9,109**	1,110,952	$ 4,671
Issued for the acquisition of AOSP and other assets (note 8)	**–**	**–**	97,561	3,818
Issued upon exercise of stock options	**9,975**	**332**	14,256	466
Previously recognized liability on stock options exercised for common shares	**–**	**120**	–	154
Purchase of common shares under Normal Course Issuer Bid	**(30,858)**	**(238)**	–	–
Balance – end of year	**1,201,886**	**$ 9,323**	1,222,769	$ 9,109

PREFERRED SHARES

Preferred shares are issuable in a series. If issued, the number of shares in each series, and the designation, rights, privileges, restrictions and conditions attached to the shares will be determined by the Board of Directors of the Company.

DIVIDEND POLICY

The Company has paid regular quarterly dividends in each year since 2001. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 6, 2019, the Board of Directors declared a quarterly dividend of $0.375 per common share, an increase from the previous quarterly dividend of $0.335 per common share. The dividend is payable on April 1, 2019. On February 28, 2018, the Board of Directors declared a quarterly dividend of $0.335 per common share, an increase from the previous quarterly dividend of $0.275 per common share. The dividend is payable on April 1, 2018. On March 1, 2017, the Board of Directors declared a quarterly dividend of $0.275 per common share, beginning with the dividend payable on April 1, 2017. On November 2, 2016, the Board of Directors declared a quarterly dividend of $0.25 per common share, beginning with the dividend payable on January 1, 2017. On March 2, 2016, the Board of Directors declared a quarterly dividend of $0.23 per common share, beginning with the dividend payable on April 1, 2016.

NORMAL COURSE ISSUER BID

On May 16, 2018, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 61,454,856 common shares, over a 12-month period commencing May 23, 2018 and ending May 22, 2019. The Company's Normal Course Issuer Bid announced in March 2017 expired on May 22, 2018.

For the year ended December 31, 2018, the Company purchased 30,857,727 common shares at a weighted average price of $41.56 per common share for a total cost of $1,282 million. Retained earnings were reduced by $1,044 million, representing the excess of the purchase price of common shares over their average carrying value. During 2017 and 2016, the Company did not purchase any common shares for cancellation. Subsequent to December 31, 2018, the Company purchased 4,340,000 common shares at a weighted average price of $35.86 per common share for a total cost of $156 million.

STOCK OPTIONS

The Company's Option Plan provides for the granting of stock options to employees. Stock options granted under the Option Plan have terms ranging from five to six years to expiry and vest over a five-year period. The exercise price of each stock option granted is determined at the closing market price of the common shares on the Toronto Stock Exchange on the day prior to the grant. Each stock option granted provides the holder the choice to purchase one common share of the Company at the stated exercise price or receive a cash payment equal to the difference between the stated exercise price and the market price of the Company's common shares on the date of surrender of the stock option.

The Option Plan is a "rolling 9%" plan, whereby the aggregate number of common shares that may be reserved for issuance under the plan shall not exceed 9% of the common shares outstanding from time to time.

The following table summarizes information relating to stock options outstanding at December 31, 2018 and 2017:

	2018			2017		
	Stock options (thousands)		**Weighted average exercise price**	Stock options (thousands)		Weighted average exercise price
Outstanding – beginning of year	**56,036**	**$**	**36.67**	58,299	$	34.22
Granted	**4,256**	**$**	**43.75**	16,052	$	42.07
Surrendered for cash settlement	**(392)**	**$**	**33.46**	(626)	$	33.18
Exercised for common shares	**(9,975)**	**$**	**33.28**	(14,256)	$	32.66
Forfeited	**(3,240)**	**$**	**38.76**	(3,433)	$	37.53
Outstanding – end of year	**46,685**	**$**	**37.92**	56,036	$	36.67
Exercisable – end of year	**19,436**	**$**	**36.03**	18,282	$	34.25

The range of exercise prices of stock options outstanding and exercisable at December 31, 2018 was as follows:

	Stock options outstanding				**Stock options exercisable**		
Range of exercise prices	**Stock options outstanding** (thousands)	**Weighted average remaining term** (years)		**Weighted average exercise price**	**Stock options exercisable** (thousands)		**Weighted average exercise price**
$22.90 – $24.99	3,120	2.04	$	22.90	1,515	$	22.90
$25.00 – $29.99	5,112	2.02	$	28.86	2,453	$	28.87
$30.00 – $34.99	6,013	0.83	$	33.27	4,831	$	33.43
$35.00 – $39.99	11,304	2.72	$	37.46	4,131	$	35.91
$40.00 – $44.99	17,107	3.23	$	43.59	5,664	$	43.60
$45.00 – $46.74	4,029	4.06	$	45.20	842	$	45.08
	46,685	2.66	$	37.92	19,436	$	36.03

15. Accumulated Other Comprehensive Income (Loss)

The components of accumulated other comprehensive income (loss), net of taxes, were as follows:

		2018		2017
Derivative financial instruments designated as cash flow hedges	**$**	**13**	$	47
Foreign currency translation adjustment		**109**		(115)
	$	**122**	$	(68)

16. Capital Disclosures

The Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined at each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of net current and long-term debt divided by the sum of the carrying value of shareholders' equity plus net current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At December 31, 2018, the ratio was within the target range at 39%.

Readers are cautioned that the debt to book capitalization ratio is not defined by IFRS and this financial measure may not be comparable to similar measures presented by other companies. Further, there are no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure in the future.

		2018		2017
Long-term debt, net [1]	**$**	**20,522**	$	22,321
Total shareholders' equity	**$**	**31,974**	$	31,653
Debt to book capitalization		**39%**		41%

(1) Includes the current portion of long-term debt, net of cash and cash equivalents.

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. At December 31, 2018, the Company was in compliance with this covenant.

17. Net Earnings (Loss) Per Common Share

		2018		2017		2016
Weighted average common shares outstanding						
– basic (thousands of shares)		**1,218,798**		1,175,094		1,100,471
Effect of dilutive stock options (thousands of shares)		**4,960**		7,729		–
Weighted average common shares outstanding						
– diluted (thousands of shares)		**1,223,758**		1,182,823		1,100,471
Net earnings (loss)	**$**	**2,591**	$	2,397	$	(204)
Net earnings (loss) per common share – basic	**$**	**2.13**	$	2.04	$	(0.19)
– diluted	**$**	**2.12**	$	2.03	$	(0.19)

In 2018, the Company excluded 23,458,000 potentially anti-dilutive stock options from the calculation of diluted earnings per common share (year ended December 31, 2017 – 17,547,000).

18. Interest and Other Financing Expense

		2018		2017		2016
Interest and other financing expense:						
Long-term debt	**$**	**867**	$	810	$	664
Less: amounts capitalized on qualifying assets		**69**		82		233
Total interest and other financing expense		**798**		728		431
Total interest income		**(59)**		(97)		(48)
Net interest and other financing expense	**$**	**739**	$	631	$	383

19. Financial Instruments

The carrying amounts of the Company's financial instruments by category were as follows:

	2018									
Asset (liability)		**Financial assets at amortized cost**		**Fair value through profit or loss**		**Derivatives used for hedging**		**Financial liabilities at amortized cost**		**Total**
Accounts receivable	**$**	**1,148**	**$**	**–**	**$**	**–**	**$**	**–**	**$**	**1,148**
Investments		**–**		**524**		**–**		**–**		**524**
Other long-term assets		**591**		**12**		**361**		**–**		**964**
Accounts payable		**–**		**–**		**–**		**(779)**		**(779)**
Accrued liabilities		**–**		**–**		**–**		**(2,356)**		**(2,356)**
Other long-term liabilities [(1)]		**–**		**(17)**		**–**		**(118)**		**(135)**
Long-term debt [(2)]		**–**		**–**		**–**		**(20,623)**		**(20,623)**
	$	**1,739**	**$**	**519**	**$**	**361**	**$**	**(23,876)**	**$**	**(21,257)**

	2017									
Asset (liability)		Financial assets at amortized cost		Fair value through profit or loss		Derivatives used for hedging		Financial liabilities at amortized cost		Total
Accounts receivable	$	2,397	$	–	$	–	$	–	$	2,397
Investments		–		893		–		–		893
Other long-term assets		510		–		204		–		714
Accounts payable		–		–		–		(775)		(775)
Accrued liabilities		–		–		–		(2,597)		(2,597)
Other long-term liabilities [(3)]		–		(38)		(65)		(469)		(572)
Long-term debt [(2)]		–		–		–		(22,458)		(22,458)
	$	2,907	$	855	$	139	$	(26,299)	$	(22,398)

(1) Includes $118 million of deferred purchase consideration payable over the next five years.
(2) Includes the current portion of long-term debt.
(3) Includes $469 million (US$375 million) of deferred purchase consideration which was paid to Marathon in March 2018.

The carrying amounts of the Company's financial instruments approximated their fair value, except for fixed rate long-term debt. The fair values of the Company's investments, recurring other long-term assets (liabilities) and fixed rate long-term debt are outlined below:

2018								
		Carrying amount		**Fair value**				
Asset (liability) (1) (2)				**Level 1**		**Level 2**		**Level 3** (4) (5)
Investments (3)	**$**	**524**	**$**	**524**	**$**	**–**	**$**	**–**
Other long-term assets	**$**	**964**	**$**	**–**	**$**	**373**	**$**	**591**
Other long-term liabilities	**$**	**(135)**	**$**	**–**	**$**	**(17)**	**$**	**(118)**
Fixed rate long-term debt (6) (7)	**$**	**(15,620)**	**$**	**(15,952)**	**$**	**–**	**$**	**–**

2017								
		Carrying amount		Fair value				
Asset (liability) (1) (2)				Level 1		Level 2		Level 3 (5)
Investments (3)	$	893	$	893	$	–	$	–
Other long-term assets	$	714	$	–	$	204	$	510
Other long-term liabilities	$	(103)	$	–	$	(103)	$	–
Fixed rate long-term debt (6) (7)	$	(15,989)	$	(17,259)	$	–	$	–

(1) Excludes financial assets and liabilities where the carrying amount approximates fair value due to the short-term nature of the asset or liability (cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, and purchase consideration paid to Marathon in March 2018).
(2) There were no transfers between Level 1, 2 and 3 financial instruments.
(3) The fair values of the investments are based on quoted market prices.
(4) The fair value of the deferred purchase consideration is based on the present value of future cash payments.
(5) The fair value of Redwater Partnership subordinated debt is based on the present value of future cash receipts.
(6) The fair value of fixed rate long-term debt has been determined based on quoted market prices.
(7) Includes the current portion of fixed rate long-term debt.

RISK MANAGEMENT

The Company periodically uses derivative financial instruments to manage its commodity price, interest rate and foreign currency exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The following provides a summary of the carrying amounts of derivative financial instruments held and a reconciliation to the Company's consolidated balance sheets.

Asset (liability)		**2018**		2017
Derivatives held for trading				
Foreign currency forward contracts	**$**	**8**	$	(38)
Crude oil WCS (1) differential swaps		**(17)**		–
Natural gas AECO basis swaps		**1**		–
Natural gas AECO fixed price swaps		**3**		–
Cash flow hedges				
Foreign currency forward contracts		**70**		(71)
Cross currency swaps		**291**		210
	$	**356**	$	101
Included within:				
Current portion of other long-term assets	**$**	**92**	$	–
Current portion of other long-term liabilities		**(17)**		(103)
Other long-term assets		**281**		204
	$	**356**	$	101

(1) Western Canadian Select.

During 2018, the Company recognized a gain of $2 million (2017 – gain of $5 million, 2016 – gain of $7 million) related to ineffectiveness arising from cash flow hedges.

The estimated fair value of derivative financial instruments in Level 2 at each measurement date have been determined based on appropriate internal valuation methodologies and/or third party indications. Level 2 fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable quoted market inputs as applicable, including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States forward interest rate yield curves, and Canadian and United States foreign exchange rates, discounted to present value as appropriate. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

The changes in estimated fair values of derivative financial instruments included in the risk management asset were recognized in the financial statements as follows:

Asset (liability)		**2018**		2017
Balance – beginning of year	**$**	**101**	$	489
Net change in fair value of outstanding derivative financial instruments recognized in:				
Risk management activities		**35**		(37)
Foreign exchange		**260**		(375)
Other comprehensive (loss) income		**(40)**		24
Balance – end of year		**356**		101
Less: current portion		**75**		(103)
	$	**281**	$	204

Net (gain) loss from risk management activities for the years ended December 31 were as follows:

		2018		2017		2016
Net realized risk management (gain) loss	**$**	**(99)**	$	(2)	$	8
Net unrealized risk management (gain) loss		**(35)**		37		25
	$	**(134)**	$	35	$	33

FINANCIAL RISK FACTORS

a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange risk.

COMMODITY PRICE RISK MANAGEMENT

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases.

At December 31, 2018, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

	Remaining term	**Volume**	**Weighted Average Price**	**Index**
Crude Oil				
WCS differential swaps	Jan 2019 – Mar 2019	28,000 bbl/d	US$17.65	WCS
WCS differential swaps	Jan 2019 – Sep 2019	8,000 bbl/d	US$23.57	WCS
Natural Gas				
AECO basis swaps	Jan 2019 – Mar 2019	10,000 MMbtu/d	US$1.39	AECO
AECO fixed price swaps	Jan 2019 – Mar 2019	30,000 GJ/d	$2.30	AECO
AECO fixed price swaps (1)	Apr 2019 – Oct 2019	10,000 GJ/d	$1.30	AECO

(1) As at March 6, 2019, the Company has hedged an additional 105,000 GJ/d of currently forecasted natural gas volumes using AECO fixed price swaps, at a weighted average price of $1.32/GJ, for April to October 2019.

The Company's outstanding commodity derivative financial instruments are expected to be settled monthly based on the applicable index pricing for the respective contract month.

INTEREST RATE RISK MANAGEMENT

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At December 31, 2018, the Company had no interest rate swap contracts outstanding.

FOREIGN CURRENCY EXCHANGE RATE RISK MANAGEMENT

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based.

At December 31, 2018 the Company had the following cross currency swap contracts outstanding:

	Remaining term	**Amount**	**Exchange rate** (US$/C$)	**Interest rate** (US$)	**Interest rate** (C$)
Cross currency					
Swaps	Jan 2019 – Nov 2021	US$500	1.022	3.45%	3.96%
	Jan 2019 – Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments were designated as hedges at December 31, 2018 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2018 the Company had US$3,506 million of foreign currency forward contracts outstanding, with terms of up to 90 days, including US$3,058 million designated as cash flow hedges.

FINANCIAL INSTRUMENT SENSITIVITIES

The following table summarizes the annualized sensitivities of the Company's 2018 net earnings and other comprehensive income (loss) to changes in the fair value of financial instruments outstanding as at December 31, 2018, resulting from changes in the specified variable, with all other variables held constant. These sensitivities are prepared on a different basis than those sensitivities disclosed in the Company's other continuous disclosure documents, are limited to the impact of changes in a specified variable applied to financial instruments only and do not represent the impact of a change in the variable on the operating results of the Company taken as a whole. Further, these sensitivities are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities. In addition, changes in fair value generally cannot be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

	2018		2017	
	Increase (decrease) to net earnings	**Increase (decrease) to other comprehensive income**	Increase (decrease) to net earnings	(Increase) decrease to other comprehensive loss
Commodity price risk [(1)]				
Increase WCS differential US$1.00/bbl	**$ (5)**	**$ –**	$ –	$ –
Decrease WCS differential US$1.00/bbl	**$ 5**	**$ –**	$ –	$ –
Increase AECO $0.10/Mcf [(2)]	**$ (1)**	**$ –**	$ –	$ –
Decrease AECO $0.10/Mcf [(2)]	**$ 1**	**$ –**	$ –	$ –
Interest rate risk				
Increase interest rate 1%	**$ (33)**	**$ (21)**	$ (42)	$ (16)
Decrease interest rate 1%	**$ 33**	**$ 25**	$ 42	$ 19
Foreign currency exchange rate risk				
Increase exchange rate by US$0.01	**$ (114)**	**$ –**	$ (105)	$ –
Decrease exchange rate by US$0.01	**$ 113**	**$ –**	$ 101	$ –

(1) Based on the Company's contracted AECO basis swap volumes at December 31, 2018, a movement of US$0.10/Mcf would not have a significant impact on net earnings or other comprehensive income.
(2) Movements in AECO are based on the Company's contracted AECO fixed price swap volumes at December 31, 2018.

b) Credit risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss to the Company by failing to discharge an obligation.

COUNTERPARTY CREDIT RISK MANAGEMENT

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At December 31, 2018, substantially all of the Company's accounts receivable were due within normal trade terms and the average expected credit loss was approximately 1% of the Company's accounts receivable balance.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. At December 31, 2018, the Company had net risk management assets of $361 million with specific counterparties related to derivative financial instruments (December 31, 2017 – $187 million).

The carrying amount of financial assets approximates the maximum credit exposure.

c) Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, commercial paper and access to debt capital markets, to meet obligations as they become due. The Company believes it has adequate bank credit facilities to provide liquidity to manage fluctuations in the timing of the receipt and/or disbursement of operating cash flows.

The maturity dates of the Company's financial liabilities were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 779	$ –	$ –	$ –
Accrued liabilities	$ 2,356	$ –	$ –	$ –
Other long-term liabilities	$ 42	$ 24	$ 69	$ –
Long-term debt (1) (2)	$ 1,141	$ 5,996	$ 3,812	$ 9,793

(1) Long-term debt represents principal repayments only and does not reflect interest, original issue discounts and premiums or transaction costs.
(2) In addition to the financial liabilities disclosed above, estimated interest and other financing payments related to long-term debt are as follows: less than one year, $836 million; one to less than two years, $755 million; two to less than five years, $1,668 million; and thereafter, $5,327 million. Interest payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2018.

20. Commitments and Contingencies

The Company has committed to certain payments as follows:

	2019	2020	2021	2022	2023	Thereafter
Product transportation and pipeline	$ 692	$ 664	$ 620	$ 516	$ 381	$ 3,991
North West Redwater Partnership service toll (1)	$ 86	$ 126	$ 157	$ 158	$ 157	$ 2,858
Offshore equipment operating leases	$ 94	$ 73	$ 75	$ 8	$ –	$ –
Office leases	$ 42	$ 42	$ 39	$ 31	$ 32	$ 89
Other	$ 85	$ 35	$ 32	$ 32	$ 31	$ 424

(1) Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service toll, which currently consists of interest and fees, with principal repayments beginning in 2020. Included in the service toll is $1,301 million of interest payable over the 30 year tolling period. See note 10.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of its various development projects. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

21. Supplemental Disclosure of Cash Flow Information

		2018		2017		2016
Changes in non-cash working capital						
Accounts receivable	**$**	**1,233**	$	(977)	$	(142)
Current income tax assets (liabilities)		**471**		527		(165)
Inventory		**(74)**		81		(79)
Prepaids and other		**(3)**		(28)		14
Accounts payable		**(7)**		175		31
Accrued liabilities		**(268)**		365		(116)
Other long-term liabilities [(1)] [(2)]		**(351)**		469		–
Net changes in non-cash working capital	**$**	**1,001**	$	612	$	(457)
Relating to:						
Operating activities	**$**	**1,346**	$	299	$	(542)
Investing activities		**(345)**		313		85
	$	**1,001**	$	612	$	(457)

		2018		2017		2016
Expenditures on exploration and evaluation assets	**$**	**282**	$	159	$	29
Net proceeds on sale of exploration and evaluation assets		**(16)**		(35)		(35)
Net expenditures (proceeds) on exploration and evaluation assets	**$**	**266**	$	124	$	(6)
Expenditures on property, plant and equipment	**$**	**4,175**	$	4,574	$	4,152
Net proceeds on sale of property, plant and equipment [(3)]		**–**		–		(349)
Net expenditures on property, plant and equipment	**$**	**4,175**	$	4,574	$	3,803

(1) Included in other long-term liabilities at December 31, 2018 is $118 million of deferred purchase consideration payable over the next five years.
(2) Included in other long-term liabilities at December 31, 2017 is $469 million (US$375 million) of deferred purchase consideration paid to Marathon.
(3) Net expenditures on property, plant and equipment in 2016 exclude non-cash share consideration of $190 million received from Inter Pipeline on the disposition of the Company's interest in the Cold Lake Pipeline.

The following table summarizes movements in the Company's liabilities arising from financing activities for the years' ended December 31, 2018 and 2017:

		Long-term debt		Cash flow hedges on US dollar debt securities		Liabilities from financing activities
At December 31, 2016	$	16,805	$	(485)	$	16,320
Changes from financing cash flows:						
Issue of long-term debt, net [(1)]		6,622		–		6,622
Settlement of hedge instruments, net		–		124		124
Changes in foreign exchange and fair value [(2)]		(969)		222		(747)
At December 31, 2017	$	22,458	$	(139)	$	22,319
Changes from financing cash flows:						
Repayment of long-term debt, net [(1)]		**(2,831)**		**–**		**(2,831)**
Changes in foreign exchange and fair value [(2)]		**996**		**(222)**		**774**
At December 31, 2018	**$**	**20,623**	**$**	**(361)**	**$**	**20,262**

(1) Includes original issue discounts and premiums, and directly attributable transaction costs.
(2) Includes foreign exchange (gain) loss, changes in the fair value of cash flow hedges on US dollar debt and the amortization of original issue discounts and premiums and directly attributable transaction costs.

22. Segmented Information

The Company's exploration and production activities are conducted in three geographic segments: North America, North Sea and Offshore Africa. These activities include the exploration, development, production and marketing of crude oil, natural gas liquids and natural gas. The Company's Oil Sands Mining and Upgrading activities are reported in a separate segment from exploration and production activities. Midstream activities include the Company's pipeline operations, an electricity co-generation system and Redwater Partnership.

Segmented revenue and segmented results include transactions between business segments. Sales between segments are made at prices that approximate market prices, taking into account the volumes involved. These transactions and any unrealized profits and losses are eliminated on consolidation, unless unrealized losses provide evidence of an impairment of the asset transferred. Sales to external customers are based on the location of the seller.

	North America			North Sea			Offshore Africa		
(millions of Canadian dollars)	**2018**	2017	2016	**2018**	2017	2016	**2018**	2017	2016
Segmented product sales									
Crude oil and NGLs	**$ 7,254**	$ 7,655	$ 5,933	**$ 753**	$ 666	$ 478	**$ 628**	$ 579	$ 532
Natural gas	**1,256**	1,506	1,276	**140**	118	92	**70**	53	71
Total segmented product sales	**8,510**	9,161	7,209	**893**	784	570	**698**	632	603
Less: royalties	**(723)**	(809)	(524)	**(2)**	(1)	(1)	**(51)**	(41)	(26)
Segmented revenue	**7,787**	8,352	6,685	**891**	783	569	**647**	591	577
Segmented expenses									
Production	**2,405**	2,362	2,186	**405**	400	403	**208**	226	200
Transportation, blending and feedstock	**2,587**	2,291	1,941	**22**	31	48	**2**	1	2
Depletion, depreciation and amortization	**3,132**	3,243	3,465	**257**	509	458	**201**	205	262
Asset retirement obligation accretion	**87**	80	66	**29**	27	35	**9**	9	12
Realized risk management (commodity derivatives)	**(10)**	(45)	6	**–**	–	–	**–**	–	–
Gain on acquisition, disposition and revaluation of properties	**(277)**	(35)	(32)	**(139)**	–	–	**(36)**	–	–
Equity loss (gain) from investments	**–**	–	–	**–**	–	–	**–**	–	–
Total segmented expenses	**7,924**	7,896	7,632	**574**	967	944	**384**	441	476
Segmented earnings (loss) before the following	**$ (137)**	$ 456	$ (947)	**$ 317**	$ (184)	$ (375)	**$ 263**	$ 150	$ 101
Non-segmented expenses									
Administration									
Share-based compensation									
Interest and other financing expense									
Risk management activities (other)									
Foreign exchange loss (gain)									
Loss (gain) from investments									
Total non-segmented expenses									
Earnings (loss) before taxes									
Current income tax expense (recovery)									
Deferred income tax expense (recovery)									
Net earnings (loss)									

Inter-segment elimination and Other includes internal transportation and electricity charges. Production, processing and other purchasing and selling activities that are not included in the above segments are also reported in the segmented information as Inter-segment eliminations and Other. In connection with the adoption of IFRS 15 on January 1, 2018 (see note 2), the Company has reclassified certain comparative figures for product sales, production expense and transportation, blending and feedstock expense for the years ended December 31, 2017 and 2016 in a manner consistent with the presentation adopted for the year ended December 31, 2018.

Operating segments are reported in a manner consistent with the internal reporting provided to the Company's chief operating decision makers.

	Oil Sands Mining and Upgrading			**Midstream**			**Inter-segment elimination and other**			**Total**		
	2018	2017	2016	**2018**	2017	2016	**2018**	2017	2016	**2018**	2017	2016
	$11,521	$ 7,072	$ 2,657	**$ 102**	$ 102	$ 114	**$ 410**	$ 448	$ 682	**$20,668**	$ 16,522	$ 10,396
	–	–	–	**–**	–	–	**148**	161	167	**1,614**	1,838	1,606
	11,521	7,072	2,657	**102**	102	114	**558**	609	849	**22,282**	18,360	12,002
	(479)	(167)	(24)	**–**	–	–	**–**	–	–	**(1,255)**	(1,018)	(575)
	11,042	6,905	2,633	**102**	102	114	**558**	609	849	**21,027**	17,342	11,427
	3,367	2,600	1,292	**21**	16	25	**58**	71	78	**6,464**	5,675	4,184
	1,087	679	80	**–**	–	–	**491**	527	751	**4,189**	3,529	2,822
	1,557	1,220	662	**14**	9	11	**–**	–	–	**5,161**	5,186	4,858
	61	48	29	**–**	–	–	**–**	–	–	**186**	164	142
	–	–	–	**–**	–	–	**–**	–	–	**(10)**	(45)	6
	–	(230)	–	**–**	(114)	(218)	**–**	–	–	**(452)**	(379)	(250)
	–	–	–	**5**	(31)	(7)	**–**	–	–	**5**	(31)	(7)
	6,072	4,317	2,063	**40**	(120)	(189)	**549**	598	829	**15,543**	14,099	11,755
	$ 4,970	$ 2,588	$ 570	**$ 62**	$ 222	$ 303	**$ 9**	$ 11	$ 20	**$ 5,484**	$ 3,243	$ (328)
										325	319	345
										(146)	134	355
										739	631	383
										(124)	80	27
										827	(787)	(55)
										341	(7)	(320)
										1,962	370	735
										3,522	2,873	(1,063)
										374	(164)	(618)
										557	640	(241)
										$ 2,591	$ 2,397	$ (204)

CAPITAL EXPENDITURES [1]

	2018			2017		
	Net expenditures	**Non-cash and fair value changes**	**Capitalized costs**	Net expenditures [2]	Non-cash and fair value changes [2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America [3]	**$ 118**	**$ (52)**	**$ 66**	$ 160	$ (184)	$ (24)
North Sea	**–**	**–**	**–**	–	–	–
Offshore Africa [4]	**(54)**	**–**	**(54)**	15	–	15
Oil Sands Mining and Upgrading	**218**	**(225)**	**(7)**	142	117	259
	$ 282	**$ (277)**	**$ 5**	$ 317	$ (67)	$ 250
Property, plant and equipment						
Exploration and Production						
North America	**$ 2,553**	**$ (362)**	**$ 2,191**	$ 2,815	$ 354	$ 3,169
North Sea	**131**	**(597)**	**(466)**	160	95	255
Offshore Africa	**228**	**(86)**	**142**	89	12	101
	2,912	**(1,045)**	**1,867**	3,064	461	3,525
Oil Sands Mining and Upgrading [5]	**1,229**	**(166)**	**1,063**	9,592	5,454	15,046
Midstream [6]	**13**	**–**	**13**	80	114	194
Head office	**21**	**–**	**21**	19	–	19
	$ 4,175	**$ (1,211)**	**$ 2,964**	$ 12,755	$ 6,029	$ 18,784

(1) This table provides a reconciliation of capitalized costs including derecognitions and does not include the impact of foreign exchange adjustments.
(2) Net expenditures on exploration and evaluation assets and property, plant and equipment for the year ended December 31, 2017 exclude non-cash share consideration of $3,818 million issued on the acquisition of AOSP and other assets. This non-cash consideration is included in non-cash and other fair value changes.
(3) The above noted figures for 2017 exclude the impact of a pre-tax cash gain of $35 million on the disposition of certain exploration and evaluation assets.
(4) The above noted figures for 2018 exclude the impact of a pre-tax cash gain of $16 million on the disposition of certain exploration and evaluation assets.
(5) Net expenditures for Oil Sands Mining and Upgrading include capitalized interest and share-based compensation.
(6) Included in 2017 is the impact of a pre-tax non-cash revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in a pipeline system.

SEGMENTED ASSETS

	2018	2017
Exploration and Production		
North America	**$ 27,199**	$ 28,705
North Sea	**1,699**	1,854
Offshore Africa	**1,471**	1,331
Other	**33**	29
Oil Sands Mining and Upgrading	**39,634**	40,559
Midstream	**1,413**	1,279
Head office	**110**	110
	$ 71,559	$ 73,867

23. Remuneration of Directors and Senior Management

Remuneration of Non-Management Directors

		2018		2017		2016
Fees earned	$	2	$	3	$	2

Remuneration of Senior Management (1)

		2018		2017		2016
Salary	$	2	$	3	$	3
Common stock option based awards		8		10		9
Annual incentive plans		4		5		5
Long-term incentive plans		15		17		15
	$	29	$	35	$	32

(1) Senior management identified above are consistent with the disclosure on Named Executive Officers provided in the Company's Information Circular to shareholders for the respective years.

Supplementary Oil & Gas Information for the Fiscal Year Ended December 31, 2018 (Unaudited)

This supplementary crude oil and natural gas information is provided in accordance with the United States Financial Accounting Standards Board ("FASB") Topic 932 – "Extractive Activities – Oil and Gas" and where applicable, financial information is prepared in accordance with International Financial Reporting Standards ("IFRS").

For the years ended December 31, 2018, 2017, 2016, and 2015 the Company filed its reserves information under National Instrument 51-101 – "Standards of Disclosure of Oil and Gas Activities" ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada.

There are significant differences to the type of volumes disclosed and the basis from which the volumes are economically determined under the United States Securities and Exchange Commission ("SEC") requirements and NI 51-101. The SEC requires disclosure of net reserves, after royalties, using 12-month average prices and current costs; whereas NI 51-101 requires gross reserves, before royalties, using forecast pricing and costs. Therefore the difference between the reported numbers under the two disclosure standards can be material.

For the purposes of determining proved crude oil and natural gas reserves for SEC requirements as at December 31, 2018, 2017, 2016, and 2015 the Company used the 12-month average price, defined by the SEC as the unweighted 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. The Company has used the following 12-month average benchmark prices to determine its 2018 reserves for SEC requirements.

Crude Oil and NGLs						Natural Gas		
WTI Cushing Oklahoma (US$/bbl)	WCS (C$/bbl)	Canadian Light Sweet (C$/bbl)	Cromer LSB (C$/bbl)	North Sea Brent (US$/bbl)	Edmonton C5+ (C$/bbl)	Henry Hub Louisiana (US$/MMBtu)	AECO (C$/MMBtu)	BC Westcoast Station 2 (C$/MMBtu)
65.55	53.67	70.32	75.54	72.09	80.65	3.02	1.46	1.25

A foreign exchange rate of US$1.00/C$1.2821 was used in the 2018 evaluation, determined on the same basis as the 12-month average price.

Net Proved Crude Oil and Natural Gas Reserves

The Company retains Independent Qualified Reserves Evaluators to evaluate and review the Company's proved crude oil, bitumen, synthetic crude oil ("SCO"), natural gas, and natural gas liquids ("NGLs") reserves.

- For the years ended December 31, 2018, 2017, 2016,and 2015, the reports by GLJ Petroleum Consultants Ltd. covered 100% of the Company's SCO reserves. With the inclusion of non-traditional resources within the definition of "oil and gas producing activities" in the SEC's modernization of oil and gas reporting rules, effective January 1, 2010 these reserves volumes are included within the Company's crude oil and natural gas reserves totals.
- For the years ended December 31, 2018, 2017, 2016 and 2015, the reports by Sproule Associates Limited and Sproule International Limited covered 100% of the Company's crude oil, bitumen, natural gas and NGLs reserves.

Proved crude oil and natural gas reserves, as defined within the SEC's Regulation S-X, are the estimated quantities of oil and gas that by analysis of geoscience and engineering data demonstrate with reasonable certainty to be economically producible, from a given date forward, from known reservoirs under existing economic conditions, operating methods and government regulations. Developed crude oil and natural gas reserves are reserves of any category that can be expected to be recovered from existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of drilling a new well; and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Undeveloped crude oil and natural gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Estimates of crude oil and natural gas reserves are subject to uncertainty and will change as additional information regarding producing fields and technology becomes available and as future economic and operating conditions change.

The following tables summarize the Company's proved and proved developed crude oil and natural gas reserves, net of royalties, as at December 31, 2018, 2017, 2016, and 2015:

	North America						
Crude Oil and NGLs (MMbbl)	**Synthetic Crude Oil**	**Bitumen**(1)	**Crude Oil & NGLs**	**North America Total**	**North Sea**	**Offshore Africa**	**Total**
Net Proved Reserves							
Reserves, December 31, 2015	2,283	1,263	471	4,017	119	73	4,209
Extensions and discoveries	–	46	15	61	–	–	61
Improved recovery	–	5	14	19	1	2	22
Purchases of reserves in place	–	3	15	18	–	–	18
Sales of reserves in place	–	–	–	–	–	–	–
Production	(45)	(71)	(43)	(159)	(9)	(8)	(176)
Economic revisions due to prices	108	23	(19)	112	(10)	1	103
Revisions of prior estimates	196	32	51	279	(8)	6	277
Reserves, December 31, 2016	2,542	1,301	504	4,347	93	74	4,514
Extensions and discoveries	–	28	17	45	–	–	45
Improved recovery	–	7	19	26	1	–	27
Purchases of reserves in place	2,232	37	67	2,336	–	–	2,336
Sales of reserves in place	–	–	–	–	–	–	–
Production	(100)	(70)	(44)	(214)	(9)	(6)	(229)
Economic revisions due to prices	–	18	17	35	18	1	54
Revisions of prior estimates	282	44	14	340	4	–	344
Reserves, December 31, 2017	4,956	1,365	594	6,915	107	69	7,091
Extensions and discoveries	**744**	**151**	**17**	**912**	**–**	**–**	**912**
Improved recovery	**–**	**10**	**50**	**60**	**1**	**3**	**64**
Purchases of reserves in place	**–**	**2**	**7**	**9**	**7**	**–**	**16**
Sales of reserves in place	**–**	**(4)**	**–**	**(4)**	**–**	**–**	**(4)**
Production	**(148)**	**(64)**	**(47)**	**(259)**	**(9)**	**(6)**	**(274)**
Economic revisions due to prices	**–**	**(45)**	**(18)**	**(63)**	**11**	**1**	**(51)**
Revisions of prior estimates	**109**	**54**	**1**	**164**	**(3)**	**4**	**165**
Reserves, December 31, 2018	**5,661**	**1,469**	**604**	**7,734**	**114**	**71**	**7,919**
Net proved developed reserves							
December 31, 2015	2,194	411	341	2,946	3	41	2,990
December 31, 2016	2,527	384	353	3,264	12	31	3,307
December 31, 2017	4,967	410	399	5,776	28	21	5,825
December 31, 2018	**5,661**	**461**	**378**	**6,500**	**37**	**34**	**6,571**

(1) Bitumen as defined by the SEC, "is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis." Under this definition, all the Company's thermal and primary heavy crude oil reserves have been classified as bitumen.

2018 total proved Crude Oil and NGLs reserves increased by 828 MMbbl primarily due to the following:

- Extensions and discoveries: Increase of 912 MMbbl primarily due to the addition of the Horizon South Pit to the Horizon oil sands mining and upgrading Project ("Horizon") (SCO), future thermal (Bitumen) well pad additions at Primrose and extension drilling/future offset additions at various primary heavy crude oil (Bitumen), Crude Oil and natural gas (NGLs) properties.
- Improved recovery: Increase of 64 MMbbl primarily due to infill drilling/future offset additions at various primary heavy crude oil (Bitumen), thermal (Bitumen), Crude Oil and natural gas (NGLs) properties as well as thermal (Bitumen) improved recovery additions.
- Purchases of reserves in place: Increase of 16 MMbbl primarily due property acquisitions in North America and North Sea core areas.
- Sale of reserves in place: Decrease of 4 MMbbl from the primary heavy crude oil (Bitumen) area.
- Production: Decrease of 274 MMbbl.
- Economic revisions due to prices: Decrease of 51 MMbbl primarily due to increased royalties at thermal (Bitumen) and Pelican Lake (Crude Oil) projects resulting from higher prices and uneconomic reserves at several North America natural gas (NGLs) core areas, partially offset by improved reserve life economics at the North Sea.
- Revisions of prior estimates: Increase of 165 MMbbl primarily due to geological model changes and improved mine/extraction/upgrading performance at the oil sands mining and upgrading projects (SCO) and improved recoveries at Primrose (Bitumen).

2017 total proved Crude Oil and NGLs reserves increased by 2,577 MMbbl primarily due to the following:

- Extensions and discoveries: Increase of 45 MMbbl primarily due to future thermal (Bitumen) well pad additions at Primrose and extension drilling/future offset additions at various primary heavy crude oil (Bitumen), Crude Oil and natural gas (NGLs) properties.
- Improved recovery: Increase of 27 MMbbl primarily due to infill drilling/future offset additions at various primary heavy crude oil (Bitumen), Crude Oil and natural gas (NGLs) properties.
- Purchases of reserves in place: Increase of 2,336 MMbbl primarily due to acquisitions of the Athabasca Oil Sands Project (SCO), Peace River thermal and Cliffdale primary heavy crude oil properties (Bitumen) and at Pelican Lake (Crude Oil).
- Production: Decrease of 229 MMbbl.
- Economic revisions due to prices: Increase of 54 MMbbl primarily due to improved reserves life economics at several North America Bitumen and Crude Oil core areas.
- Revisions of prior estimates: Increase of 344 MMbbl primarily due to Horizon (SCO) revising the stratigraphic well density used to define proved reserves quantities and increasing the Horizon (SCO) total-volume-to-bitumen-in-place-ratio, partially offset by Horizon (SCO) adopting a low fines mine plan. Additionally, there were overall positive revisions at several North America Bitumen and Crude Oil core areas including improved recoveries at Primrose (Bitumen).

2016 total proved Crude Oil and NGLs reserves increased by 305 MMbbl primarily due to the following:

- Extensions and discoveries: Increase of 61 MMbbl primarily due to future thermal (Bitumen) well pad additions at Primrose and extension drilling/future offset additions at various primary heavy crude oil (Bitumen) and Crude Oil properties.
- Improved recovery: Increase of 22 MMbbl primarily due to infill drilling/future offset additions at various primary heavy crude oil (Bitumen) and Crude Oil properties.
- Purchases of reserves in place: Increase of 18 MMbbl due to various property acquisitions in several North America core areas.
- Production: Decrease of 176 MMbbl.
- Economic revisions due to prices: Increase of 103 MMbbl primarily due to reduced royalties at Horizon (SCO), thermal (Bitumen) and Pelican Lake (Crude Oil) projects, partially offset by the loss of uneconomic reserves at several North America Bitumen and Crude Oil core areas.
- Revisions of prior estimates: Increase of 277 MMbbl primarily due to Horizon (SCO) revising the stratigraphic well density used to define proved reserves quantities. Additionally, there were overall positive revisions at several North America Bitumen and Crude Oil core areas.

Natural Gas (Bcf)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Net Proved Reserves				
Reserves, December 31, 2015	4,523	38	21	4,582
Extensions and discoveries	176	–	–	176
Improved recovery	166	–	3	169
Purchases of reserves in place	85	–	–	85
Sales of reserves in place	(5)	–	–	(5)
Production	(571)	(14)	(11)	(596)
Economic revisions due to prices	(572)	(10)	1	(581)
Revisions of prior estimates	792	11	11	814
Reserves, December 31, 2016	4,594	25	25	4,644
Extensions and discoveries	261	–	–	261
Improved recovery	179	–	–	179
Purchases of reserves in place	106	–	–	106
Sales of reserves in place	–	–	–	–
Production	(558)	(14)	(7)	(579)
Economic revisions due to prices	403	5	(1)	407
Revisions of prior estimates	214	9	(1)	222
Reserves, December 31, 2017	5,199	25	16	5,240
Extensions and discoveries	**90**	**–**	**–**	**90**
Improved recovery	**414**	**–**	**–**	**414**
Purchases of reserves in place	**67**	**–**	**–**	**67**
Sales of reserves in place	**(3)**	**–**	**–**	**(3)**
Production	**(523)**	**(11)**	**(8)**	**(542)**
Economic revisions due to prices	**(746)**	**–**	**(2)**	**(748)**
Revisions of prior estimates	**(192)**	**13**	**15**	**(164)**
Reserves, December 31, 2018	**4,306**	**27**	**21**	**4,354**
Net proved developed reserves				
December 31, 2015	2,883	26	15	2,924
December 31, 2016	2,805	18	18	2,841
December 31, 2017	3,081	22	9	3,112
December 31, 2018	**2,382**	**23**	**12**	**2,417**

2018 total proved Natural Gas reserves decreased by 886 Bcf primarily due to the following:

- Extensions and discoveries: Increase of 90 Bcf primarily due to extension drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Improved recovery: Increase of 414 Bcf primarily due to infill drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Purchases of reserves in place: Increase of 67 Bcf primarily due to property acquisitions in several North America core areas.
- Sale of reserves in place: Decrease of 3 Bcf.
- Production: Decrease of 542 Bcf.
- Economic revisions due to prices: Decrease of 748 Bcf due to uneconomic reserves at several North America Natural Gas core areas.
- Revisions of prior estimates: Decrease of 164 Bcf primarily due to the removal of future extension and infill undeveloped reserves at several North America properties as a result of revised Company development plans.

2017 total proved Natural Gas reserves increased by 596 Bcf primarily due to the following:

- Extensions and discoveries: Increase of 261 Bcf primarily due to extension drilling/future offset additions in the Montney and Spirit River formations of northwest Alberta and northeast British Columbia.
- Improved recovery: Increase of 179 Bcf primarily due to infill drilling/future offset additions in the Montney and Spirit River formations of northwest Alberta and northeast British Columbia.
- Purchases of reserves in place: Increase of 106 Bcf primarily due to property acquisitions in several North America core areas.
- Production: Decrease of 579 Bcf.
- Economic revisions due to prices: Increase of 407 Bcf due to improved reserves life economics at several North America Natural Gas core areas.
- Revisions of prior estimates: Increase of 222 Bcf primarily due to overall positive revisions at several North America core areas triggered by production optimizations and reduced production costs.

2016 total proved Natural Gas reserves increased by 62 Bcf primarily due to the following:

- Extensions and discoveries: Increase of 176 Bcf primarily due to extension drilling/future offset additions in the Montney and Spirit River formations of northwest Alberta and northeast British Columbia.
- Improved recovery: Increase of 169 Bcf primarily due to infill drilling/future offset additions in the Montney and Spirit River formations of northwest Alberta and northeast British Columbia.
- Purchases of reserves in place: Increase of 85 Bcf primarily due to various property acquisitions in several North America core areas.
- Production: Decrease of 596 Bcf.
- Economic revisions due to prices: Decrease of 581 Bcf due to the loss of uneconomic reserves at several North America areas.
- Revisions of prior estimates: Increase of 814 Bcf primarily due to overall positive revisions at several North America core areas triggered by production optimizations and reduced production costs.

Capitalized Costs Related to Crude Oil and Natural Gas Activities

	2018			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Proved properties	**$ 110,154**	**$ 7,321**	**$ 5,471**	**$ 122,946**
Unproved properties	**2,600**	**–**	**37**	**2,637**
	112,754	**7,321**	**5,508**	**125,583**
Less: accumulated depletion and depreciation	**(48,862)**	**(5,735)**	**(4,203)**	**(58,800)**
Net capitalized costs	**$ 63,892**	**$ 1,586**	**$ 1,305**	**$ 66,783**

	2017			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Proved properties	$ 106,900	$ 7,126	$ 4,881	$ 118,907
Unproved properties	2,541	–	91	2,632
	109,441	7,126	4,972	121,539
Less: accumulated depletion and depreciation	(44,779)	(5,653)	(3,719)	(54,151)
Net capitalized costs	$ 64,662	$ 1,473	$ 1,253	$ 67,388

	2016			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Proved properties	$ 88,685	$ 7,380	$ 5,132	$ 101,197
Unproved properties	2,306	–	76	2,382
	90,991	7,380	5,208	103,579
Less: accumulated depletion and depreciation	(41,139)	(5,584)	(3,797)	(50,520)
Net capitalized costs	$ 49,852	$ 1,796	$ 1,411	$ 53,059

Costs Incurred in Crude Oil and Natural Gas Activities

	2018			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Property acquisitions				
Proved	**$ 214**	**$ 127**	**$ –**	**$ 341**
Unproved	**340**	**–**	**(89)**	**251**
Exploration	**116**	**–**	**35**	**151**
Development	**3,245**	**110**	**212**	**3,567**
Costs incurred	**$ 3,915**	**$ 237**	**$ 158**	**$ 4,310**

	2017			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	$ 15,091	$ –	$ –	$ 15,091
Unproved	321	–	–	321
Exploration	112	–	15	127
Development	3,753	255	101	4,109
Costs incurred	$ 19,277	$ 255	$ 116	$ 19,648

	2016			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	$ 50	$ –	$ –	$ 50
Unproved	–	–	–	–
Exploration	17	–	9	26
Development	4,125	186	116	4,427
Costs incurred	$ 4,192	$ 186	$ 125	$ 4,503

Results of Operations from Crude Oil and Natural Gas Producing Activities

The Company's results of operations from crude oil and natural gas producing activities for the years ended December 31, 2018, 2017, and 2016 are summarized in the following tables:

	2018			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Crude oil and natural gas revenue, net of royalties, blending and feedstock costs	**$ 16,065**	**$ 891**	**$ 647**	**$ 17,603**
Production	**(5,772)**	**(405)**	**(208)**	**(6,385)**
Transportation	**(929)**	**(22)**	**(2)**	**(953)**
Depletion, depreciation and amortization	**(4,689)**	**(257)**	**(201)**	**(5,147)**
Asset retirement obligation accretion	**(148)**	**(29)**	**(9)**	**(186)**
Petroleum revenue tax	**–**	**12**	**–**	**12**
Income tax	**(1,223)**	**(76)**	**(51)**	**(1,350)**
Results of operations	**$ 3,304**	**$ 114**	**$ 176**	**$ 3,594**

	2017			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Crude oil and natural gas revenue, net of royalties, blending and feedstock costs	$ 13,083	$ 784	$ 578	$ 14,445
Production	(4,962)	(400)	(226)	(5,588)
Transportation	(790)	(31)	(1)	(822)
Depletion, depreciation and amortization	(4,463)	(509)	(205)	(5,177)
Asset retirement obligation accretion	(128)	(27)	(9)	(164)
Petroleum revenue tax	–	78	–	78
Income tax	(740)	42	(28)	(726)
Results of operations	$ 2,000	$ (63)	$ 109	$ 2,046

	2016			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Crude oil and natural gas revenue, net of royalties, blending and feedstock costs	$ 7,791	$ 565	$ 577	$ 8,933
Production	(3,478)	(403)	(200)	(4,081)
Transportation	(623)	(48)	(2)	(673)
Depletion, depreciation and amortization	(4,127)	(458)	(262)	(4,847)
Asset retirement obligation accretion	(95)	(35)	(12)	(142)
Petroleum revenue tax	–	333	–	333
Income tax	143	18	(22)	139
Results of operations	$ (389)	$ (28)	$ 79	$ (338)

Standardized Measure of Discounted Future Net Cash Flows from Proved Crude Oil and Natural Gas Reserves and Changes Therein

The following standardized measure of discounted future net cash flows from proved crude oil and natural gas reserves has been computed using the 12-month average price, defined by the SEC as the unweighted 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, costs as at the balance sheet date and year-end statutory income tax rates. A discount factor of 10% has been applied in determining the standardized measure of discounted future net cash flows. The Company does not believe that the standardized measure of discounted future net cash flows will be representative of actual future net cash flows and should not be considered to represent the fair value of the crude oil and natural gas properties. Actual net cash flows will differ from the presented estimated future net cash flows due to several factors including:

- Future production will include production not only from proved properties, but may also include production from probable and possible reserves;
- Future production of crude oil and natural gas from proved properties will differ from reserves estimated;
- Future production rates will vary from those estimated;
- Future prices and costs rather than 12-month average prices and costs as at the balance sheet date will apply;
- Economic factors such as interest rates, income tax rates, regulatory and fiscal environments and operating conditions will change;
- Future estimated income taxes do not take into account the effects of future exploration and evaluation expenditures; and
- Future development and asset retirement obligations will differ from those estimated.

Future net revenues, development, production and asset retirement obligation costs have been based upon the estimates referred to above. The following tables summarize the Company's future net cash flows relating to proved crude oil and natural gas reserves based on the standardized measure as prescribed in FASB Topic 932 - "Extractive Activities - Oil and Gas":

(millions of Canadian dollars)	North America 2018	North Sea 2018	Offshore Africa 2018	Total 2018
Future cash inflows	**$ 500,557**	**$ 12,002**	**$ 6,447**	**$ 519,006**
Future production costs	**(193,387)**	**(5,148)**	**(2,284)**	**(200,819)**
Future development costs and asset retirement obligations	**(63,202)**	**(2,909)**	**(1,099)**	**(67,210)**
Future income taxes	**(60,526)**	**(1,484)**	**(626)**	**(62,636)**
Future net cash flows	**183,442**	**2,461**	**2,438**	**188,341**
10% annual discount for timing of future cash flows	**(126,699)**	**(545)**	**(771)**	**(128,015)**
Standardized measure of future net cash flows	**$ 56,743**	**$ 1,916**	**$ 1,667**	**$ 60,326**

(millions of Canadian dollars)	North America 2017	North Sea 2017	Offshore Africa 2017	Total 2017
Future cash inflows	$ 413,180	$ 8,740	$ 4,786	$ 426,706
Future production costs	(198,304)	(4,168)	(1,876)	(204,348)
Future development costs and asset retirement obligations	(61,169)	(2,853)	(1,258)	(65,280)
Future income taxes	(35,645)	(595)	(248)	(36,488)
Future net cash flows	118,062	1,124	1,404	120,590
10% annual discount for timing of future cash flows	(73,171)	(59)	(455)	(73,685)
Standardized measure of future net cash flows	$ 44,891	$ 1,065	$ 949	$ 46,905

(millions of Canadian dollars)	North America 2016	North Sea 2016	Offshore Africa 2016	Total 2016
Future cash inflows	$ 206,729	$ 5,999	$ 4,129	$ 216,857
Future production costs	(92,070)	(3,284)	(1,659)	(97,013)
Future development costs and asset retirement obligations	(42,167)	(3,249)	(1,234)	(46,650)
Future income taxes	(15,396)	280	(125)	(15,241)
Future net cash flows	57,096	(254)	1,111	57,953
10% annual discount for timing of future cash flows	(33,590)	271	(319)	(33,638)
Standardized measure of future net cash flows	$ 23,506	$ 17	$ 792	$ 24,315

The principal sources of change in the standardized measure of discounted future net cash flows are summarized in the following table:

(millions of Canadian dollars)	**2018**	2017	2016
Sales of crude oil and natural gas produced, net of production costs	**$ (10,229)**	$ (8,013)	$ (4,159)
Net changes in sales prices and production costs	**20,386**	7,466	(7,305)
Extensions, discoveries and improved recovery	**2,807**	481	700
Changes in estimated future development costs	**(698)**	(5,548)	1,750
Purchases of proved reserves in place	**396**	25,782	352
Sales of proved reserves in place	**(55)**	–	(2)
Revisions of previous reserve estimates	**2,711**	4,245	3,668
Accretion of discount	**6,119**	3,075	3,527
Changes in production timing and other	**(955)**	(662)	(2,137)
Net change in income taxes	**(7,061)**	(4,236)	385
Net change	**13,421**	22,590	(3,221)
Balance - beginning of year	**46,905**	24,315	27,536
Balance - end of year	**$ 60,326**	$ 46,905	$ 24,315

Ten-Year Review

Years ended December 31	**2018**	2017	2016	2015	2014	2013	2012	2011	2010 (8)	2009 (9)
FINANCIAL INFORMATION (1) (Cdn $ millions, except per share amounts)										
Net earnings (loss)	**2,591**	2,397	(204)	(637)	3,929	2,270	1,892	2,643	1,673	1,580
Per share – basic ($/share)	**2.13**	2.04	(0.19)	(0.58)	3.60	2.08	1.72	2.41	1.54	1.46
Per share – diluted ($/share)	**2.12**	2.03	(0.19)	(0.58)	3.58	2.08	1.72	2.40	1.53	1.46
Cash flows from operating activities	**10,121**	7,262	3,452	5,632	8,459	7,218	6,209	6,243	6,282	5,812
Adjusted funds flow (2)	**9,088**	7,347	4,293	5,785	9,587	7,477	6,013	6,547	6,333	6,090
Per share – basic ($/share)	**7.46**	6.25	3.90	5.29	8.78	6.87	5.48	5.98	5.82	5.62
Per share – diluted ($/share)	**7.43**	6.21	3.89	5.28	8.74	6.86	5.47	5.94	5.78	5.62
Cash flows used in investing activities	**4,814**	13,102	3,811	5,465	11,177	7,006	5,927	5,963	5,189	3,558
Net capital expenditures (3)	**4,731**	17,129	3,794	3,853	11,744	7,274	6,308	6,414	5,514	2,997
Balance sheet information (Cdn $ millions)										
Working capital surplus (deficiency)	**(601)**	513	1,056	1,193	(673)	(1,574)	(1,264)	(894)	(1,200)	(514)
Exploration and evaluation assets	**2,637**	2,632	2,382	2,586	3,557	2,609	2,611	2,475	2,402	–
Property, plant and equipment, net	**64,559**	65,170	50,910	51,475	52,480	46,487	44,028	41,631	38,429	39,115
Total assets	**71,559**	73,867	58,648	59,275	60,200	51,754	48,980	47,278	42,954	41,024
Long-term debt	**20,623**	22,458	16,805	16,794	14,002	9,661	8,736	8,571	8,485	9,658
Shareholders' equity	**31,974**	31,653	26,267	27,381	28,891	25,772	24,283	22,898	20,368	19,426
SHARE INFORMATION (1)										
Common shares outstanding (thousands)	**1,201,886**	1,222,769	1,110,952	1,094,668	1,091,837	1,087,322	1,092,072	1,096,460	1,090,848	1,084,654
Weighted average shares outstanding – basic (thousands)	**1,218,798**	1,175,094	1,100,471	1,093,862	1,091,754	1,088,682	1,097,084	1,095,582	1,088,096	1,083,850
Weighted average shares outstanding – diluted (thousands)	**1,223,758**	1,182,823	1,100,471	1,093,862	1,096,822	1,090,541	1,099,519	1,102,582	1,095,648	1,083,850
Dividends declared ($/share) (4)	**$ 1.34**	$ 1.10	$ 0.94	$ 0.92	$ 0.90	$ 0.575	$ 0.42	$ 0.36	$ 0.30	$ 0.21
Trading statistics (1)										
TSX – C$										
Trading volume (thousands)	**806,254**	588,422	653,727	728,033	717,580	683,003	729,700	800,044	661,832	1,040,320
Share Price ($/share)										
High	**$ 49.08**	$ 47.00	$ 46.74	$ 42.46	$ 49.57	$ 36.04	$ 41.12	$ 50.50	$ 45.00	$ 39.50
Low	**$ 30.11**	$ 35.90	$ 21.27	$ 25.01	$ 31.00	$ 28.44	$ 25.58	$ 27.25	$ 31.97	$ 17.93
Close	**$ 32.94**	$ 44.92	$ 42.79	$ 30.22	$ 35.92	$ 35.94	$ 28.64	$ 38.15	$ 44.35	$ 38.00
NYSE – US$										
Trading volume (thousands)	**796,971**	608,008	892,220	951,311	812,521	645,403	844,647	937,481	759,327	1,514,614
Share Price ($/share)										
High	**$ 38.19**	$ 36.78	$ 35.28	$ 34.46	$ 46.65	$ 33.92	$ 41.38	$ 52.04	$ 44.77	$ 38.26
Low	**$ 21.85**	$ 27.53	$ 14.60	$ 18.94	$ 26.53	$ 26.98	$ 25.01	$ 25.69	$ 30.00	$ 13.85
Close	**$ 24.13**	$ 35.72	$ 31.88	$ 21.83	$ 30.88	$ 33.84	$ 28.87	$ 37.37	$ 44.42	$ 35.98
RATIOS										
Debt to book capitalization (5)	**39%**	41%	39%	38%	33%	27%	26%	27%	29%	33%
Return on average common shareholders' equity, after tax (5)	**8%**	8%	(1%)	(2%)	14%	9%	8%	12%	8%	8%
Daily production before royalties per ten thousand common shares (BOE/d) (1)	**9.0**	7.9	7.3	7.8	7.2	6.2	6.0	5.5	5.8	5.3
Total proved plus probable reserves per common share (BOE) (1) (6)	**11.1**	9.7	8.3	8.3	8.1	7.3	7.2	6.9	6.3	5.8
Net asset value ($/share) (1) (7)	**$ 101.89**	$ 81.41	$ 74.77	$ 73.39	$ 78.99	$ 72.41	$ 62.38	$ 70.37	$ 64.58	$ 64.92

(1) Restated to reflect two-for-one share splits in May 2010.

(2) Adjusted funds flow (previously referred to as funds flow from operations) is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The derivation of this measure is discussed in the MD&A.

(3) Net capital expenditures is a non-GAAP measure that the Company considers a key measure as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. For additional information and details, refer to the net capital expenditures table in the Company's MD&A.

(4) On March 6, 2019, the Board of Directors approved a quarterly dividend of $0.375 per common share, an increase from the previous quarterly dividend of $0.335 per common share. The dividend is payable on April 1, 2019.

(5) Refer to the "Liquidity and Capital Resources" section of the MD&A for the definitions of these items.

(6) Based upon company gross reserves (forecast price and costs, before royalties), using year-end common shares outstanding. Prior to 2010, Company gross reserves were prepared using constant prices and costs.

Years ended December 31	2018	2017	2016	2015	2014	2013	2012	2011	2010 [8]	2009 [9]
OPERATING INFORMATION										
Crude oil and NGLs (MMbbl) [10]										
Company net proved reserves (after royalties)										
North America	**7,163**	6,423	3,909	3,645	3,380	3,290	3,268	3,007	2,763	2,664
North Sea	**119**	120	134	158	204	224	227	228	252	240
Offshore Africa	**72**	70	74	74	78	80	85	87	101	123
	7,354	6,613	4,117	3,877	3,662	3,594	3,580	3,322	3,116	3,027
Company net proved plus probable reserves (after royalties)										
North America	**9,456**	8,353	6,015	5,806	5,609	5,135	5,119	4,777	4,293	4,172
North Sea	**186**	180	252	284	308	325	332	349	376	387
Offshore Africa	**98**	102	108	113	119	122	127	131	149	179
	9,740	8,635	6,375	6,203	6,036	5,582	5,578	5,257	4,818	4,738
Natural gas (Bcf) [10]										
Company net proved reserves (after royalties)										
North America	**6,005**	6,032	5,845	5,383	5,054	3,684	3,540	3,778	3,638	3,027
North Sea	**27**	21	41	39	83	91	82	98	78	67
Offshore Africa	**21**	15	23	21	36	38	48	54	76	85
	6,053	6,068	5,909	5,443	5,173	3,813	3,670	3,930	3,792	3,179
Company net proved plus probable reserves (after royalties)										
North America	**8,681**	8,454	7,888	7,361	6,791	5,138	4,907	5,125	4,870	3,992
North Sea	**38**	32	85	96	114	125	102	134	107	94
Offshore Africa	**44**	47	55	50	68	70	76	83	113	124
	8,763	8,533	8,028	7,507	6,973	5,333	5,085	5,342	5,090	4,210
Total net proved reserves (after royalties) (MMBOE)	**8,363**	7,625	5,102	4,784	4,524	4,230	4,191	3,977	3,748	3,557
Total net proved plus probable reserves (after royalties) (MMBOE)	**11,202**	10,057	7,713	7,454	7,198	6,471	6,426	6,147	5,666	5,440
Daily production (before royalties)										
Crude oil and NGLs (Mbbl/d)										
North America – Exploration and Production	**351**	359	351	400	391	344	326	296	271	234
North America – Oil Sands Mining and Upgrading	**426**	282	123	123	111	100	86	40	91	50
North Sea	**24**	23	24	22	17	18	20	30	33	38
Offshore Africa	**20**	20	26	19	12	16	19	23	30	33
	821	685	524	564	531	478	451	389	425	355
Natural gas (MMcf/d)										
North America	**1,490**	1,601	1,622	1,663	1,527	1,130	1,198	1,231	1,217	1,287
North Sea	**32**	39	38	36	7	4	2	7	10	10
Offshore Africa	**26**	22	31	27	21	24	20	19	16	18
	1,548	1,662	1,691	1,726	1,555	1,158	1,220	1,257	1,243	1,315
Total production (before royalties) (MBOE/d)	**1,079**	962	806	852	790	671	655	599	632	575
Product pricing										
Average crude oil and NGLs price ($/bbl) [11]	**$ 46.92**	$ 48.57	$ 36.93	$ 41.13	$ 77.04	$ 73.81	$ 72.44	$ 79.16	$ 65.81	$ 57.68
Average natural gas price ($/Mcf) [11]	**$ 2.61**	$ 2.76	$ 2.32	$ 3.16	$ 4.83	$ 3.30	$ 2.70	$ 3.99	$ 4.08	$ 4.53
Average SCO price ($/bbl) [11][12]	**$ 68.61**	$ 63.98	$ 58.59	$ 61.39	$ 100.27	$ 99.18	$ 90.74	$ 101.48	$ 77.89	$ 70.83

(7) Net present value, discounted at 10%, of the future net revenue (before income tax and excluding the ARO for development existing as at December 31, 2018) of the Company's total proved plus probable crude oil, natural gas and NGL reserves prepared using forecast prices and costs, as reported in the Company's AIF, plus the estimated market value of core unproved property at $285/acre (2018 to 2015, $300/acre for core unproved property from 2014 to 2010, $250/acre for core undeveloped land in 2009), less net debt and using common shares outstanding. Net debt is long term debt plus/minus the working capital deficit/surplus. Future development costs and abandonment and reclamation costs attributable to future development activity have been applied against the future net revenue.

(8) 2010 comparative figures have been restated in accordance with IFRS issued at December 31, 2011.

(9) Comparative figures for years prior to 2010 are in accordance with Canadian GAAP as previously reported and may not be prepared on a basis consistent with IFRS as adopted.

(10) For the years 2010 to 2018, company net reserves were prepared using forecast prices and costs; prior to 2010, company net reserves were prepared using constant prices and costs.

(11) For the years 2011 to 2018, product prices reflect realized product prices before transportation costs. Prior to 2011, product prices were reported net of transportation costs.

(12) For years 2017 and 2018, average SCO product price includes AOSP realized product prices net of blending and feedstock costs.

Corporate Information

Board of Directors

***Catherine M. Best, FCA,** ICD.D (1)(2)
Corporate Director
Calgary, Alberta

N. Murray Edwards, O.C.
Corporate Director
London, England

***Timothy W. Faithful** (1)(3)
Corporate Director
London, England

***Christopher L. Fong** (3)(5)
Corporate Director
Calgary, Alberta

***Ambassador Gordon D. Giffin** (1)(4)
Partner, Dentons US LLP
Atlanta, Georgia

***Wilfred A. Gobert** (2)(4)(5)
Corporate Director
Calgary, Alberta

Steve W. Laut (5)
Executive Vice-Chairman,
Canadian Natural Resources Limited
Calgary, Alberta

Tim S. McKay (3)
President, Canadian Natural Resources Limited
Calgary, Alberta

***Honourable Frank J. McKenna,** P.C., O.C., O.N.B., Q.C. (2)(4)
Deputy Chair, TD Bank Group
Cap Pelé, New Brunswick

***David A. Tuer** (1)(5)
Chairman, Optiom Inc.
Calgary, Alberta

***Annette M. Verschuren,** O.C. (2)(3)
Chairman and Chief Executive Officer, NRSTOR Inc.
Toronto, Ontario

Senior Officers

N. Murray Edwards
Executive Chairman

Steve W. Laut
Executive Vice-Chairman

Tim S. McKay
President

Darren M. Fichter
Chief Operating Officer, Exploration and Production

Scott G. Stauth
Chief Operating Officer, Oil Sands

Corey B. Bieber
Chief Financial Officer and Senior Vice-President, Finance

Troy J.P. Andersen
Senior Vice-President, Canadian Conventional
Field Operations

Trevor J. Cassidy
Senior Vice-President, Thermal

Réal M. Cusson
Senior Vice-President, Marketing

Allan E. Frankiw
Senior Vice-President, Production

Jay E. Froc
Senior Vice-President, Oil Sands Mining and Upgrading

Ron K. Laing
Senior Vice-President, Corporate Development and Land

Pamela A. McIntyre
Senior Vice-President, Safety, Risk Management
and Innovation

Bill R. Peterson
Senior Vice-President, Development Operations

Ken W. Stagg
Senior Vice-President, Exploration

Robin S. Zabek
Senior Vice-President, Exploitation

Paul M. Mendes
Vice-President, Legal, General Counsel
and Corporate Secretary

Betty Yee
Vice-President, Land

(1) Audit Committee member
(2) Compensation Committee member
(3) Health, Safety, Asset Integrity and Environmental Committee member
(4) Nominating, Governance and Risk Committee member
(5) Reserves Committee member
* Determined to be independent by the Nominating, Governance and Risk Committee of the Board of Directors and pursuant to the independent standards established under National Instrument 58-101 and the New York Stock Exchange Corporate Governance Listing Standards.

Corporate Offices

HEAD OFFICE

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INVESTOR RELATIONS

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INTERNATIONAL OFFICE

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Aberdeen AB11 6NJ Scotland

REGISTRAR AND TRANSFER AGENT

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

Computershare Investor Services LLC
New York, New York

AUDITORS

PricewaterhouseCoopers LLP
Calgary, Alberta

INDEPENDENT QUALIFIED RESERVES EVALUATORS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Sproule Associates Limited
Calgary, Alberta

Sproule International Limited
Calgary, Alberta

STOCK LISTING – CNQ

Toronto Stock Exchange
The New York Stock Exchange

COMPANY DEFINITION

Throughout the annual report, Canadian Natural Resources Limited is referred to as "us", "we", "our", "Canadian Natural", or the "Company".

CURRENCY

All amounts are reported in Canadian currency unless otherwise stated.

ABBREVIATIONS

Abbreviations can be found on page 13.

METRIC CONVERSION CHART

To convert	To	Multiply by
barrels	cubic metres	0.159
thousand cubic feet	cubic metres	28.174
feet	metres	0.305
miles	kilometres	1.609
acres	hectares	0.405
tonnes	tons	1.102

COMMON SHARE DIVIDEND

The Company paid its first dividend on its common shares on April 1, 2001. Since then, dividends have been paid quarterly. The following table shows the aggregate amount of the cash dividends declared per common share of the Company and accrued in each of its last three years ended December 31, 2018.

	2018	2017	2016
Cash dividends declared per common share(1)	**$1.34**	$1.10	$0.94

(1) Annualized dividend value.

NOTICE OF ANNUAL MEETING

Canadian Natural's Annual and Special Meeting of the Shareholders will be held on Thursday, May 9, 2019 at 1:00 p.m. Mountain Daylight Time in the Macleod C&D Exhibition Halls of the Telus Convention Centre, Calgary, Alberta.

Corporate Governance

Canadian Natural's corporate governance practices and disclosure of those practices are in compliance with National Policy 58-201 Corporate Governance Guidelines and National Instrument 58-101 Disclosure of Corporate Governance Practices. Canadian Natural, as a "foreign private issuer" in the United States, may rely on home jurisdiction listing standards for compliance with most of the New York Stock Exchange ("NYSE") Corporate Governance Listing Standards but must disclose any significant differences between its corporate governance practices and those required for U.S. companies listed on the NYSE.

Canadian Natural follows Toronto Stock Exchange ("TSX") rules with respect to shareholder approval of equity compensation plans and material revisions to such plans. TSX rules provide that only the creation of or material amendments to equity compensation plans which provide for new issuance of securities are subject to shareholder approval. However, the NYSE requires shareholder approval of all equity compensation plans whether they provide for the delivery of newly issued securities, or rely on securities acquired in the open market by the issuing company for the purposes of redistribution to plan beneficiaries, and material revisions to such plans. Canadian Natural has a performance share unit plan pursuant to which common shares are purchased through the TSX. This is not a new issue of securities under the performance share unit plan and under TSX rules the plan is not subject to shareholder approval.

Canadian Natural has included as exhibits to its Annual Report on Form 40-F for the 2018 fiscal year filed with the United States Securities and Exchange Commission certificates of the Chief Executive Officer and Chief Financial Officer certifying as to disclosure controls and procedures and internal control over financial reporting

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