

## Disclosure of Reserves Data

The reserves data (the "Reserves Data") set forth below in this reserves report (the "Report") for Sinopec Canada Energy Ltd. (the "Company") is based upon an independent evaluation of the Operated Project's Core and Static assets and audit of Non-Core assets by McDaniel & Associates Consultants Limited ("McDaniel") with an effective date of December 31, 2025 contained in the McDaniel reserve report ("McDaniel Report") dated January 29, 2026. The opening reserves balances represent the reserves for Company's Operated Project at December 31, 2024. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Company and the net present values of future net revenue for these reserves using forecast prices and costs. The McDaniel Report has been prepared in accordance with the standards contained in the COGE Handbook and National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities*. We engaged McDaniel to provide an evaluation of proved and proved plus probable reserves and no request was made to evaluate possible reserves.

All of the Company's Operated Project reserves are in Canada, and specifically in the provinces of Alberta and British Columbia.

**It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained, and variances could be material. The recovery and reserve estimates of Company's Operated Project crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.**

## Abbreviations and Conversions

ADR	Abandonment, Decommissioning, Reclamation
AECO	physical storage and trading hub for natural gas on the TransCanada Alberta Transmission System (NOVA) which is the delivery point for the various Alberta index prices
API	American Petroleum Institute
API	measure of the density or gravity of liquid petroleum products derived from a specific gravity
Bbl	barrel
Bbl/d	barrels per day
Bcf	billion cubic feet
boe	barrels of oil equivalent converting 6 Mcf of natural gas or one barrel of natural gas liquids to one barrel of oil equivalent
boe/d	barrels of oil equivalent per day
GJ	Gigajoule
HVL	high value liquids, includes light oil, condensate, and pentane
MBbl	one thousand barrels
Mboe	one thousand barrels of oil equivalent
MMboe	one million barrels of oil equivalent
Mcf	one thousand cubic feet
m <sup>3</sup>	cubic meters
Mcf/d	one thousand cubic feet per day
MMBtu	one million British Thermal Units
MMcf	one million cubic feet
MMcf/d	one million cubic feet per day
MMBbl	one million barrels
M\$	one thousand dollars
MM\$	one million dollars
NGLs	natural gas liquids
WTI	West Texas Intermediate crude oil that serves as the benchmark crude oil for the NYMEX crude oil contract delivered in Cushing, Oklahoma

## FORWARD-LOOKING STATEMENTS

Certain statements contained within this Report constitute forward-looking statements. These statements relate to future events or future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in these forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this Report should not be unduly relied upon. These statements speak only as of the date of this Report.

The actual results could differ materially from those anticipated in forward-looking statements as a result of certain risk factors, including those set forth below:

- volatility in market prices for oil, NGLs and natural gas;
- counterparty credit risk;
- changes or fluctuations in oil, NGLs and natural gas production levels;
- infrastructure or transportation constraints for oil, NGLs or natural gas;
- liabilities inherent in and as a result of oil and natural gas operations;
- adverse regulatory rulings, orders and decisions;
- attracting, retaining and motivating skilled personnel;
- uncertainties associated with estimating oil and natural gas reserves;
- fluctuations in foreign exchange or interest rates;
- actions by governmental or regulatory authorities including changes in royalty structures and programs and income tax laws or changes in tax laws and incentive programs relating to the oil and natural gas industry generally;
- limitations on insurance;
- changes in accounting policies and standards;
- changes in environmental or other legislation applicable to our operations including environmental laws and regulations associated with drilling and completion technologies, and our ability to comply with current and future environmental and other laws; and
- geological, technical, drilling and processing problems and other difficulties in producing oil, NGLs and natural gas reserves.

Statements relating to "reserves" or "resources" are by their nature deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future.

## Reserves Information

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
cubic meters	cubic feet	35.315
Mcf	cubic meters	28.174
Bbl	cubic meters	0.159
cubic meters	Bbl	6.290
Feet	Meters	0.305
Meters	Feet	3.281
Miles	Kilometers	1.609
Kilometers	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

### Summary of Reserves

The following tables summarize, as of December 31, 2025, the Company Operated Project's oil, natural gas liquids, and natural gas reserves and the estimated net present values of future net cash revenues associated with such reserves, together with certain information, estimates, and assumptions associated with such reserve estimates, as contained in the McDaniel Report. The data contained in the tables set out below is a summary of the evaluations, and as a result, the numbers in the tables may not add due to rounding. In these tables, Gross refers to the Company's working interest plus royalty interest before royalties paid and Net refers to the Company's working interest plus royalty interest after royalties paid.

Reserves	Light and Medium Oil		Heavy Oil		Tight Oil	
	Gross (MBbl)	Net (MBbl)	Gross (MBbl)	Net (MBbl)	Gross (MBbl)	Net (MBbl)
Proved						
Developed producing	4,048	3,549	-	-	53	59
Developed non-producing	852	670	-	-	60	44
Undeveloped	634	484	-	-	-	-
Total Proved	5,534	4,703	-	-	113	103
Probable	1,308	1,042	-	-	18	15
<b>Total proved plus probable</b>	<b>6,843</b>	<b>5,745</b>	<b>-</b>	<b>-</b>	<b>131</b>	<b>118</b>

Reserves	Conventional Natural Gas		Coalbed Methane		Shale Gas	
	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)
Proved						
Developed producing	68,371	63,456	89	85	100,176	90,865
Developed non-producing	13,463	11,894	7	7	11,989	10,956
Undeveloped	32,686	28,836	-	-	227,070	204,981
Total Proved	114,519	104,186	97	92	339,235	306,801
Probable	30,100	26,559	5	5	637,492	563,331
<b>Total proved plus probable</b>	<b>144,620</b>	<b>130,745</b>	<b>102</b>	<b>97</b>	<b>976,727</b>	<b>870,132</b>

# Reserves Information

Reserves	Natural Gas Liquids		Total	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mboe)	Net (Mboe)
Proved				
Developed producing	8,529	6,729	40,736	36,071
Developed non-producing	750	584	5,904	5,106
Undeveloped	23,533	18,564	67,460	58,018
<b>Total Proved</b>	<b>32,812</b>	<b>25,877</b>	<b>114,101</b>	<b>99,196</b>
Probable	51,667	39,145	164,259	138,518
<b>Total proved plus probable</b>	<b>84,478</b>	<b>65,022</b>	<b>278,360</b>	<b>237,714</b>

Net Present Value of Future Net Revenue (before income taxes)					
(000s) discounted at	0%	5%	10%	15%	20%
Proved					
Developed producing	\$(404,550)	\$16,467	\$115,331	\$142,638	\$149,367
Developed non-producing	\$74,567	\$54,381	\$42,381	\$34,250	\$28,312
Undeveloped	\$779,306	\$516,510	\$353,020	\$246,991	\$175,661
<b>Total Proved</b>	<b>\$449,323</b>	<b>\$587,358</b>	<b>\$510,732</b>	<b>\$423,879</b>	<b>\$353,339</b>
Probable	\$1,735,951	\$1,025,259	\$649,134	\$436,699	\$309,612
<b>Total proved plus probable</b>	<b>\$2,185,275</b>	<b>\$1,612,617</b>	<b>\$1,159,866</b>	<b>\$860,578</b>	<b>\$662,951</b>

Net Present Value of Future Net Revenue (after income taxes)					
(000s) discounted at	0%	5%	10%	15%	20%
Proved					
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<b>Total Proved</b>	<b>\$449,323</b>	<b>\$587,358</b>	<b>\$510,732</b>	<b>\$423,879</b>	<b>\$353,339</b>
Probable	\$1,451,431	\$850,003	\$535,906	\$360,676	\$256,935
<b>Total Proved plus Probable</b>	<b>\$1,900,755</b>	<b>\$1,437,361</b>	<b>\$1,046,638</b>	<b>\$784,555</b>	<b>\$610,274</b>

Future Net Revenue (undiscounted)								
(000s)	Revenue	Royalties	Operating Costs	Development Costs	ADR <sup>(1)</sup> Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Proved								
Developed producing	\$1,565,663	\$212,793	\$1,017,311	\$55,015	\$685,094	-\$404,550	\$0	-\$404,550
Developed non-producing	\$237,702	\$37,783	\$108,689	\$16,664	\$0	\$74,567	\$0	\$74,567
Undeveloped	\$2,916,711	\$520,308	\$923,247	\$679,864	\$13,986	\$779,306	\$0	\$779,306
<b>Total Proved</b>	<b>\$4,720,077</b>	<b>\$770,884</b>	<b>\$2,049,247</b>	<b>\$751,543</b>	<b>\$699,080</b>	<b>\$449,323</b>	<b>\$0</b>	<b>\$449,323</b>
Probable	\$6,808,212	\$1,317,432	\$2,709,909	\$1,024,263	\$20,656	\$1,735,951	\$284,520	\$1,451,431
<b>Total proved plus probable</b>	<b>\$11,528,289</b>	<b>\$2,088,316</b>	<b>\$4,759,157</b>	<b>\$1,775,805</b>	<b>\$719,736</b>	<b>\$2,185,275</b>	<b>\$284,520</b>	<b>\$1,900,755</b>

(1) Abandonment, Decommissioning, Reclamation

# Reserves Information



<b>Future Net Revenue by Production Group (discounted at 10%)</b>	<b>Future Net Revenue before Income Taxes (000s)</b>	<b>Unit Value<sup>(3)</sup> (\$/boe or \$/Mcf)</b>
<b>Proved</b>		
Light and medium crude oil <sup>(1)</sup>	\$(181,733)	\$(40)
Tight oil <sup>(1)</sup>	\$3,167	\$31
Natural gas <sup>(2)</sup> (Non Assoc. & Assoc.)	\$194,884	\$2
Coalbed methane	\$26	-
Shale Gas	\$494,388	\$2
<b>Total Proved</b>	<b>\$510,732</b>	
<b>Proved plus probable</b>		
Light and medium crude oil <sup>(1)</sup>	\$(236,659)	\$(42)
Tight oil <sup>(1)</sup>	\$3,608	\$31
Natural gas <sup>(2)</sup> (Non Assoc. & Assoc.)	\$257,714	\$2
Coalbed methane	\$30	-
Shale Gas	\$1,135,172	\$1
<b>Total Proved plus probable</b>	<b>\$1,159,866</b>	

- (1) Including solution gas, other by-products, oil and gas facilities, production maintenance, ADR cost. Note Company Facilities/P&M/ADR costs are burdening oil assets only in this summary.
- (2) Including by-products but excluding natural gas from oil wells
- (3) Calculated using net oil or net gas reserves and forecast prices and cost assumptions.

## Pricing Assumptions

The forecast cost and price assumptions include increases in wellhead selling prices and account for inflation with respect to future operating and capital costs. The estimated future net revenue to be derived from the production of the reserves includes an inflation rate assumption of 2% per year applied to costs starting in 2027, together with the following price forecasts supplied by McDaniel.

Year	West Texas			
	Intermediate Crude Oil (\$US/Bbl)	Edmonton par Crude Oil (\$Cdn/Bbl)	Natural Gas At AECO (\$Cdn/MMbtu)	Foreign Exchange (\$US/\$Cdn)
2026	\$62.50	\$80.82	\$3.00	0.73
2027	\$66.30	\$85.93	\$3.32	0.73
2028	\$72.83	\$94.78	\$3.64	0.73
2029	\$74.28	\$96.67	\$3.71	0.73
2030	\$75.77	\$98.61	\$3.79	0.73
2031	\$77.29	\$100.58	\$3.86	0.73
2032	\$78.83	\$102.59	\$3.94	0.73
2033	\$80.41	\$104.64	\$4.02	0.73
2034	\$82.02	\$106.73	\$4.10	0.73
2035	\$83.66	\$108.87	\$4.18	0.73
2036	\$85.33	\$111.05	\$4.27	0.73
2037	\$87.04	\$113.27	\$4.35	0.73
2038	\$88.78	\$115.53	\$4.44	0.73
2039	\$90.55	\$117.84	\$4.53	0.73
2040 (escalation 2% thereafter)	\$92.36	\$120.20	\$4.62	0.73

# Reserves Information

Weighted average historical prices realized by the Company Operated Project for the year ended December 31, 2025 were \$Cdn 1.95 per Mcf for natural gas, \$Cdn 82.22 per Bbl for light oil (\$Cdn 82.27 per Bbl for HVL) and \$Cdn 19.69 per Bbl for NGLs.

## Reserves Reconciliation

### Reconciliation of Gross Reserves

	Light and Medium Oil			Heavy Oil		
	Proved (MBbl)	Probable (MBbl)	Proved plus Probable (MBbl)	Proved (MBbl)	Probable (MBbl)	Proved plus Probable (MBbl)
<b>December 31, 2024</b>	6,856	1,548	8,403	-	-	-
Extensions and improved recovery	143	50	193	-	-	-
Technical revisions	(542)	(275)	(817)	-	-	-
Discoveries	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-
Acquisitions & Dispositions	-	-	-	-	-	-
Economic factors	(108)	(15)	(123)	-	-	-
Production	(814)	-	(814)	-	-	-
<b>December 31, 2025</b>	<b>5,534</b>	<b>1,308</b>	<b>6,843</b>	-	-	-

### Reconciliation of Gross Reserves

	Tight Oil			Natural Gas Liquids		
	Proved (MBbl)	Probable (MBbl)	Proved plus Probable (MBbl)	Proved (MBbl)	Probable (MBbl)	Proved plus Probable (MBbl)
<b>December 31, 2024</b>	115	18	133	35,558	48,133	83,691
Extensions and improved recovery	-	-	-	1,609	629	2,238
Technical revisions	6	0	6	(2,596)	2,931	335
Discoveries	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-
Acquisitions & Dispositions	-	-	-	-	-	-
Economic factors	-	-	-	(27)	(27)	(53)
Production	(8)	-	(8)	(1,733)	-	(1,733)
<b>December 31, 2025</b>	<b>113</b>	<b>18</b>	<b>131</b>	<b>32,812</b>	<b>51,667</b>	<b>84,478</b>

# Reserves Information



## Reconciliation of Gross Reserves

	Conventional Natural Gas			Shale Gas		
	Proved (MMcf)	Probable (MMcf)	Proved plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved plus Probable (MMcf)
<b>December 31, 2024</b>	129,814	31,840	161,654	379,946	626,519	1,006,465
Extensions and improved recovery	1,723	690	2,413	11,360	4,574	15,933
Technical revisions	(4,822)	(2,697)	(7,519)	(30,853)	6,749	(24,104)
Discoveries	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-
Acquisitions & Dispositions	-	-	-	-	-	-
Economic factors	(789)	267	(522)	(563)	(350)	(912)
Production	(11,407)	-	(11,407)	(20,655)	-	(20,655)
<b>December 31, 2025</b>	<b>114,519</b>	<b>30,100</b>	<b>144,620</b>	<b>339,235</b>	<b>637,492</b>	<b>976,727</b>

## Reconciliation of Gross Reserves

	Coalbed Methane			Oil Equivalent		
	Proved (MMcf)	Probable (MMcf)	Proved plus Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved plus Probable (Mboe)
<b>December 31, 2024</b>	138	9	147	127,512	159,426	286,939
Extensions and improved recovery	-	-	-	3,932	1,557	5,489
Technical revisions	27	(3)	24	(9,074)	3,331	(5,743)
Discoveries	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-
Acquisitions & Dispositions	-	-	-	-	-	-
Economic factors	(27)	(1)	(28)	(365)	(55)	(420)
Production	(42)	-	(42)	(7,906)	-	(7,906)
<b>December 31, 2025</b>	<b>97</b>	<b>5</b>	<b>102</b>	<b>114,101</b>	<b>164,259</b>	<b>278,360</b>

## Additional Information Relating to Reserves Data

### Undeveloped Reserves

Undeveloped reserves are attributed by McDaniel in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to place them on production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to place them on production.

We do not intend to carry proved undeveloped reserves for long periods of time unless there is a good reason not to produce these reserves in the short term. Where there is sufficient economic justification, we intend to take steps to accelerate and enhance production. These steps could involve dually completing and/or re-drilling to twin wells for secondary zones.

About 42% of our total proved plus probable undeveloped reserves are attributed to proved undeveloped locations. The remaining 58% results from identified drilling locations that do not yet meet the required confidence factor or development timeframe for a booking in the proved category.

## Reserves Information

For the year ended December 31, 2025, \$CDN 91 million was spent on capital expenditures including land and property acquisitions, net of dispositions. A portion of the 2026 development capital is planned to be used to convert proved undeveloped reserves and probable reserves into proved developed producing reserves. Allocating capital to properties and timing of development is based on the economics and performance of the respective properties.

We plan to continue pursuing development opportunities such as drilling, completions, and facilities upgrades, in order to convert proved undeveloped and probable reserves into proved, developed producing reserves. In instances where land rights are expected to expire within one year, we may engage in farmout arrangements which would eliminate the potential expiry and possibly result in certain proved undeveloped and probable reserves becoming proved developed producing reserves.

There are a number of factors that could result in delayed or canceled development, including the following: (i) changing economic conditions (due to pricing, operating, and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to landowners, weather conditions and regulatory approvals).

### Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of current proved undeveloped reserves that were first attributed in each of the most recent four fiscal years. In the following table, "First Attributed" refers to reserves first attributed (newly added) at the year-end of the corresponding fiscal year.

	Light and Medium Oil		Heavy Oil		Tight Oil	
	First	Total at	First	Total at	First	Total at
	Attributed	Year-end	Attributed	Year-end	Attributed	Year-end
	(MBbl)	(MBbl)	(MBbl)	(MBbl)	(MBbl)	(MBbl)
2022	109	1,007	-	-	-	-
2023	419	1,107	-	-	-	-
2024	271	963	-	-	-	-
2025	143	634	-	-	-	-

	Conventional Natural Gas		Shale Gas		Natural Gas Liquids	
	First	Total at	First	Total at	First	Total at
	Attributed	Year-end	Attributed	Year-end	Attributed	Year-end
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBbl)	(MBbl)
2022	242	25,725	2,762	281,842	418	22,668
2023	3,954	26,442	-	279,671	421	25,318
2024	20,181	48,486	10,899	252,608	3,211	26,238
2025	377	32,686	11,360	227,070	1,496	23,533

# Reserves Information

## Proved Undeveloped Reserves

	Oil Equivalent	
	First Attributed (Mboe)	Total at Year-end (Mboe)
2022	1,028	81,246
2023	1,499	77,559
2024	8,662	77,383
2025	3,595	67,460

Approximately 91% of Sinopec Canada Operated Project's future capital associated with proved undeveloped reserves is scheduled for expenditure between 2026 and 2030, the remaining is associated with facilities and capitalized maintenance on existing wells. The major areas of development are the Wapiti and Brazeau properties, which together represent 99% of the total proved undeveloped future development costs and 99% of the total proved undeveloped reserves. The remaining proved undeveloped capital and reserves are primarily associated with the Tomahawk area.

## Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of current probable undeveloped reserves that were first attributed in each of the most recent four fiscal years. In the following table, "First Attributed" refers to reserves first attributed (newly added) at year-end of the corresponding fiscal year.

### Probable Undeveloped Reserves

	Light and Medium Oil		Heavy Oil		Tight Oil	
	First Attributed (MBbl)	Total at Year-end (MBbl)	First Attributed (MBbl)	Total at Year-end (MBbl)	First Attributed (MBbl)	Total at Year-end (MBbl)
2022	37	373	-	-	-	-
2023	141	390	-	-	-	-
2024	91	339	-	-	-	-
2025	50	237	-	-	-	-

### Probable Undeveloped Reserves

	Conventional Natural Gas		Shale Gas		Natural Gas Liquids	
	First Attributed (MMcf)	Total at Year-end (MMcf)	First Attributed (MMcf)	Total at Year-end (MMcf)	First Attributed (MBbl)	Total at Year-end (MBbl)
2022	91	10,972	898	606,170	133	49,306
2023	1,322	8,920	-	573,717	143	44,320
2024	6,493	15,958	-	587,575	12,051	45,791
2025	169	10,503	4,574	599,743	586	48,950

### Probable Undeveloped Reserves

	Oil Equivalent	
	First Attributed (Mboe)	Total at Year-end (Mboe)
2022	335	125,537
2023	504	141,816
2024	38,295	146,719
2025	1,426	150,895

## Reserves Information

Approximately 42% of Sinopec Canada Operated Project's future capital associated with proved plus probable undeveloped reserves is scheduled for expenditure between 2026 and 2030. The major areas of development are the Wapiti and Brazeau properties, which represent 99.6% of the total proved plus probable undeveloped future development costs and 99.7% of the total proved plus probable undeveloped reserves. The remaining proved plus probable undeveloped capital and reserves are primarily associated with the Tomahawk area.

### **Significant Factors or Uncertainties Affecting Reserves Data**

The process of evaluating reserves is inherently complex and such evaluations are estimates only. Our reserves have been evaluated and audited by McDaniel, an independent engineering firm. The reserve evaluation process requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance become available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, geological evaluation, engineering data, prices, and economic conditions. These factors and assumptions include among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves. As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions, and governmental restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance, and geologic conditions or production. These revisions can be either positive or negative. High operating costs substantially reduce our netback, which in turn reduces the amount of cash available for reinvestment in drilling opportunities. This becomes most relevant during periods of low commodity prices when profits are more significantly impacted by high costs.

Our oil and gas properties have no material extraordinary risks or uncertainties beyond those which are inherent in other oil and gas producing companies.

### **Future Development Costs**

The following table sets forth development costs deducted in the estimation of the future net revenue attributable to the reserve categories noted below.

<b>Future Development Costs (undiscounted)</b>	<b>Proved Plus Probable Reserves</b>	<b>Proved Plus Probable Reserves</b>
<i>(000s)</i>	<b>Proved Reserves</b>	<b>Proved Plus Probable Reserves</b>
2026	\$37,075	\$40,433
2027	\$80,913	\$86,057
2028	\$245,212	\$253,026
2029	\$188,516	\$193,321
2030	\$110,470	\$191,313
Remaining	\$89,356	\$1,011,655
<b>Total</b>	<b>\$751,543</b>	<b>\$1,775,805</b>

Future development costs are capital expenditures required in the future for us to convert proved non-producing reserves and probable reserves into proved developed producing reserves. We anticipate using a combination of internally generated cash provided by operating activities, and, as required, financing from Sinopec International Petroleum Exploration and Production Corporation ("SIPC") and external sources to fund these future development costs. The Company has the support of its operating parent, SIPC, which provides financial support as required. Based on the commodity price and cost assumptions adopted for the forecast prices and

## Reserves Information

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costs case, all the expenditures included in the future development costs are economic as they enhance the net present values of the proved developed producing reserves.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth herein and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any of these properties uneconomic.

## Other Oil and Natural Gas Information

### Overview

Our operational strategies and activities are directed toward maximizing value over the long term. We intend to utilize our extensive operating experience and employ prudent oil and natural gas business practices to increase value through development and optimization activities on both existing and acquired oil and natural gas properties. We expect to achieve this value creation through an active development program directed towards lower risk development, continuous optimization of our assets, and active management of risk.

Optimization of our assets will take the form of debottlenecking, compression, installation or enhancement of artificial lift, water injection, fluid handling and fluid processing, facility optimization, and other activities. These activities are usually smaller projects with attractive rates of return given the limited capital investment required and rapid payback. We expect to use a variety of technical and operating experts, both internal and external, to achieve these results.

We currently focus our development activities on the Western Canadian Sedimentary Basin. Our development activities are expected to be funded by internally generated cash provided by operating activities, intercompany financing, and external sources. We do not anticipate that the costs of funding these development activities will have a material effect on our disclosed oil and gas reserves or future net revenue attributable to those reserves.

### Description of Principal Oil and Natural Gas Properties

The following is a description of the principal oil and natural gas properties in which we have an interest. Unless otherwise specified, production estimates, gross and net acres, and well count information are as of December 31, 2025. Reserve amounts are stated, before deduction of royalties as of December 31, 2025, based on forecast cost and price assumptions as evaluated in the McDaniel Report. **The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties due to the effects of aggregation.**

#### *Pembina Cash Generating Unit*

The Pembina CGU comprises the Company Operated Project's Brazeau, Tomahawk, and Warburg properties, in addition to a number of minor properties.

The Brazeau property is located approximately 145 kilometers southwest of Edmonton, Alberta near the community of Drayton Valley. The Company operates three facilities for the processing of oil and the compression of gas in the Brazeau area. The gas is shipped for final processing at the neighboring Brazeau River Complex with the option to flow to other processing plants in the area.

The Warburg and Tomahawk properties are located approximately 30 kilometers east of Drayton Valley. The Company operates a number of sweet oil facilities in the Warburg/Tomahawk area. The previously operating sour facility in Tomahawk is still in operation, processing only sweet crude since the permanent shut-in of the Minnehik Buck Lake sour gas plant.

The majority of reserves in the Pembina area are associated with the Rock Creek, Cardium, Ellerslie, Nisku, and Belly River formations with additional reserves assigned to various other cretaceous zones. Total proved plus probable reserves in the McDaniel Report are approximately 31.6 MMboe for our interests in this area at year-end 2025.

#### *West Central Cash Generating Unit*

The West Central properties are primarily located approximately 230 kilometers northwest of Edmonton, Alberta. The West Central area contains five significant sub-properties: Fox Creek, Medicine Lodge, Oldman, Ansell South, Marlboro, and a number of minor properties. The major producing formations in the West Central area are the liquids-rich Duvernay, Wilrich, and Notikewin zones.

Total proved plus probable reserves in the McDaniel Report are approximately 5.5 MMboe to our interests in this area at year-end 2025.

## Other Oil and Natural Gas Information

### Peace River Arch Cash Generating Unit

The Peach River Arch (PRA) CGU comprises 3 major properties, Wapiti, Karr, and Elmworth in addition to a number of minor properties in proximity to the City of Grande Prairie, in northwest Alberta. In Wapiti and Karr, development and production are primarily in the Montney formation, which is being developed with horizontal wells. In Elmworth, reserves are developed with both vertical and horizontal gas wells and production is commingled from the Cadotte, Falher, Bluesky, Gething, Cadomin, and Nikanassin formations. The Company has identified numerous additional Montney horizontal well opportunities in the PRA area of the Operated Project. McDaniel has assigned total proved plus probable reserves of approximately 241.7 MMboe to our interest in this area at year-end 2025.

### Oil and Natural Gas Wells

The following table sets forth the number and status of wells in which we had a working interest as of December 31, 2025. Although many wells produce both oil and natural gas, a well is categorized as an oil well or a natural gas well based upon the proportion of oil or natural gas production that constitutes the majority of production from that well.

#### Number and Status of Wells

	Oil Wells				Natural Gas Wells			
	Producing Gross <sup>(1)</sup>	Net	Non-Producing Gross <sup>(1)</sup>	Net	Producing Gross <sup>(1)</sup>	Net	Non-Producing Gross <sup>(1)</sup>	Net
Alberta	352	288	188	139	552	289	313	171
British Columbia	0	0	0	0	0	0	0	0
Saskatchewan	0	0	11	4	0	0	10	3
Total	352	288	199	142	552	289	323	174

(1) Gross wells include unit wells

### Properties with no Attributed Reserves

The following table sets out our undeveloped land holdings as of December 31, 2025. Our undeveloped land holdings have no reserves attributed to them.

Undeveloped Land Holdings	Undeveloped Acres	
	Gross	Net
Alberta	358,751	237,736
British Columbia	9,801	4,864
Saskatchewan	0	0
Total	368,552	242,600

We expect that rights to explore, develop and exploit 1,769 net acres of our undeveloped land holdings will be subject to potential expiry within one year. We have no material work commitments on such properties. Where we determine appropriate, we may continue expiring leases by either making the necessary applications to extend or by performing the necessary work. The Company calculates gross undeveloped acres by including undrilled spacing units in each lease or license where we have a working interest for the Operated Project. The net undeveloped acreage is calculated by multiplying the gross acreage by our working interest percentage. There are several economic factors and significant uncertainties that affect the anticipated development of Operated Project's properties with no attributed reserves. The Company will be required to make substantial capital expenditures in order to prove, exploit, develop and produce oil and natural gas from these properties in the future.