Reserves Information

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, 2024 contained in the McDaniel reserve report ("McDaniel Report") dated January 28, 2025. The opening reserves balances represent the reserves for Company's Operated Project at December 31, 2023. 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^3	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.

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, 2024, 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	4,978	4,289	-	-	7	19
Developed non-producing	915	691	-	-	108	84
Undeveloped	963	708	-	-	-	-
Total Proved	6,856	5,687	-	-	115	104
Probable	1,548	1,187	-	-	18	16
Total proved plus probable	**8,403**	**6,875**	**-**	**-**	**133**	**119**

Reserves	**Conventional Natural Gas**		**Coalbed Methane**		**Shale Gas**	
	Gross *(MMcf)*	**Net** *(MMcf)*	**Gross** *(MMcf)*	**Net** *(MMcf)*	**Gross** *(MMcf)*	**Net** *(MMcf)*
Proved						
Developed producing	66,628	62,213	124	117	115,274	104,576
Developed non-producing	14,701	12,576	14	13	12,064	10,905
Undeveloped	48,486	43,122	-	-	252,608	227,925
Total Proved	129,814	117,911	138	130	379,946	343,407
Probable	31,840	28,017	9	9	626,519	553,059
Total proved plus probable	**161,654**	**145,928**	**147**	**140**	**1,006,465**	**896,466**

Reserves Information

Reserves	Natural Gas Liquids Gross (MBbl)	Natural Gas Liquids Net (MBbl)	Total Gross (Mboe)	Total Net (Mboe)
Proved				
Developed producing	8,422	6,486	43,745	38,612
Developed non-producing	898	653	6,384	5,344
Undeveloped	26,238	20,534	77,383	66,416
Total Proved	35,558	27,673	127,512	110,372
Probable	48,133	36,056	159,426	134,107
Total proved plus probable	**83,691**	**63,729**	**286,939**	**244,479**

Net Present Value of Future Net Revenue (before income taxes)

(000s) discounted at	0%	5%	10%	15%	20%
Proved					
Developed producing	$(329,050)	$81,063	$170,989	$192,251	$194,382
Developed non-producing	$81,960	$59,429	$45,929	$36,803	$30,182
Undeveloped	$929,241	$609,818	$414,557	$289,194	$205,324
Total Proved	$682,151	$750,309	$631,475	$518,248	$429,888
Probable	$1,850,501	$1,098,761	$705,771	$484,197	$350,949
Total proved plus probable	**$2,532,651**	**$1,849,070**	**$1,337,246**	**$1,002,445**	**$780,836**

Net Present Value of Future Net Revenue (after income taxes)

(000s) discounted at	0%	5%	10%	15%	20%
Proved					
Developed producing	($329,050)	$81,063	$170,989	$192,251	$194,382
Developed non-producing	$81,960	$59,429	$45,929	$36,803	$30,182
Undeveloped	$929,241	$609,818	$414,557	$289,194	$205,324
Total Proved	$682,151	$750,309	$631,475	$518,248	$429,888
Probable	$1,533,971	$904,495	$580,328	$399,842	$292,323
Total Proved plus Probable	**$2,216,122**	**$1,654,804**	**$1,211,803**	**$918,089**	**$722,211**

Future Net Revenue (undiscounted)

(000s)	**Revenue**	**Royalties**	**Operating Costs**	**Development Costs**	**ADR[(1)] Costs**	**Future Net Revenue Before Income Taxes**	**Income Taxes**	**Future Net Revenue After Income Taxes**
Proved								
Developed producing	$1,809,983	$257,793	$1,156,944	$59,071	$665,224	-$329,050	$0	-$329,050
Developed non-producing	$274,125	$49,734	$123,648	$18,783	$0	$81,960	$0	$81,960
Undeveloped	$3,512,503	$642,340	$1,100,670	$823,455	$16,798	$929,241	$0	$929,241
Total Proved	$5,596,611	$949,868	$2,381,263	$901,309	$682,021	$682,151	$0	$682,151
Probable	$6,898,083	$1,364,775	$2,698,617	$964,310	$19,881	$1,850,501	$316,530	$1,533,971
Total proved plus probable	**$12,494,695**	**$2,314,643**	**$5,079,880**	**$1,865,618**	**$701,902**	**$2,532,651**	**$316,530**	**$2,216,122**

(1) Abandonment, Decommissioning, Reclamation

Reserves Information

Future Net Revenue by Production Group (discounted at 10%)	Future Net Revenue before Income Taxes *(000s)*	Unit Value[3] *($/boe or $/Mcf)*
Proved		
Light and medium crude oil[1]	-$177,882	-$32.17
Tight oil[1]	$3,243	$31.33
Natural gas[2] (Non Assoc. & Assoc.)	$219,639	$2.04
Coalbed methane	$20	$0.15
Shale Gas	$586,456	$1.72
Total Proved	**$631,475**	
Proved plus probable		
Light and medium crude oil[1]	-$218,852	-$32.68
Tight oil[1]	$3,674	$30.78
Natural gas[2] (Non Assoc. & Assoc.)	$287,503	$2.15
Coalbed methane	$27	$0.19
Shale Gas	$1,264,895	$1.41
Total Proved plus probable	**$1,337,246**	

(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 2026, 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)
2025	$72.50	$95.89	$2.75	0.73
2026	$73.95	$97.11	$3.57	0.73
2027	$75.43	$98.34	$3.64	0.73
2028	$76.94	$100.31	$3.71	0.73
2029	$78.48	$102.31	$3.79	0.73
2030	$80.05	$104.36	$3.86	0.73
2031	$81.65	$106.45	$3.94	0.73
2032	$83.28	$108.57	$4.02	0.73
2033	$84.95	$110.75	$4.10	0.73
2034	$86.64	$112.96	$4.18	0.73
2035	$88.38	$115.22	$4.27	0.73
2036	$90.14	$117.52	$4.35	0.73
2037	$91.95	$119.87	$4.44	0.73
2038	$93.79	$122.27	$4.53	0.73
2039 (escalation 2% thereafter)	$95.66	$124.72	$4.62	0.73

Weighted average historical prices realized by the Company Operated Project for the year ended December 31, 2024 were $Cdn 1.57 per Mcf for natural gas, $Cdn 90.44 per Bbl for light oil ($Cdn 92.54 per Bbl for HVL) and $Cdn 24.08 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)*
December 31, 2023	6,932	1,629	8,561	58	14	71
Extensions and improved recovery	450	153	603	-	-	-
Technical revisions	(47)	(221)	(268)	(58)	(14)	(71)
Discoveries	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-
Acquisitions & Dispositions	(9)	(2)	(11)	-	-	-
Economic factors	96	(13)	84	-	-	-
Production	(565)	-	(565)	-	-	-
December 31, 2024	**6,856**	**1,548**	**8,403**	**-**	**-**	**-**

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)*
December 31, 2023	131	19	150	35,782	47,021	82,803
Extensions and improved recovery	-	-	-	3,215	12,052	15,267
Technical revisions	(4)	(5)	(9)	(1,498)	(10,863)	(12,361)
Discoveries	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-
Acquisitions & Dispositions	-	-	-	(10)	(3)	(13)
Economic factors	-	4	4	(153)	(75)	(228)
Production	(12)	-	(12)	(1,777)	-	(1,777)
December 31, 2024	**115**	**18**	**133**	**35,558**	**48,133**	**83,691**

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)*
December 31, 2023	115,472	29,070	144,542	404,810	611,683	1,016,493
Extensions and improved recovery	20,492	6,603	27,095	10,899	150,427	161,326
Technical revisions	5,220	(3,035)	2,185	(17,522)	(135,083)	(152,605)
Discoveries	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-
Acquisitions & Dispositions	(96)	(22)	(118)	-	-	-
Economic factors	(2,296)	(776)	(3,072)	(2,435)	(508)	(2,943)
Production	(8,977)	-	(8,977)	(15,806)	-	(15,806)
December 31, 2024	**129,814**	**31,840**	**161,654**	**379,946**	**626,519**	**1,006,465**

Reconciliation of Gross Reserves

	Coalbed Methane			Oil Equivalent		
	Proved *(MMcf)*	**Probable** *(MMcf)*	**Proved plus Probable** *(MMcf)*	**Proved** *(Mboe)*	**Probable** *(Mboe)*	**Proved plus Probable** *(Mboe)*
December 31, 2023	37	31	68	129,623	155,480	285,103
Extensions and improved recovery	-	-	-	8,896	38,377	47,273
Technical revisions	138	(28)	111	(1,458)	(34,126)	(35,584)
Discoveries	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-
Acquisitions & Dispositions	-	-	-	(35)	(8)	(43)
Economic factors	(6)	6	-	(846)	(297)	(1,143)
Production	(32)	-	(32)	(8,667)	-	(8,667)
December 31, 2024	**138**	**9**	**147**	**127,512**	**159,426**	**286,939**

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 47% of our total proved plus probable undeveloped reserves are attributed to proved undeveloped locations. The remaining 53% results from identified drilling locations that do not yet meet the required confidence factor or development timeframe for a booking in the proved category.

For the year ended December 31, 2024, $CDN 102.6 million was spent on capital expenditures including land and property acquisitions, net of dispositions. A portion of the 2025 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.

Proved 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)***
2021	-	1,127	-	-	-	-
2022	109	1,007	-	-	-	-
2023	419	1,107	-	-	-	-
2024	271	963	-	-	-	-

Proved 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)*
2021	-	22,593	3,511	214,639	353	15,497
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

Proved Undeveloped Reserves	Oil Equivalent	
	First Attributed (Mboe)	Total at Year-end (Mboe)
2021	939	56,163
2022	1,028	81,246
2023	1,499	77,559
2024	8,662	77,383

Approximately 91% of Sinopec Canada Operated Project's future capital associated with proved undeveloped reserves is scheduled for expenditure between 2025 and 2029, 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)*
2021	-	786	-	-	-	2,330
2022	37	373	-	-	-	-
2023	141	390	-	-	-	-
2024	91	339	-	-	-	-

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)*
2021	-	30,556	1,156	768,548	117	58,865
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	150,427	587,575	12,051	45,791

Probable Undeveloped Reserves	Oil Equivalent	
	First Attributed *(Mboe)*	Total at Year-end *(Mboe)*
2021	309	195,165
2022	335	125,537
2023	504	141,816
2024	38,295	146,719

Approximately 43% of Sinopec Canada Operated Project's future capital associated with proved plus probable undeveloped reserves is scheduled for expenditure between 2025 and 2029. 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 becomes 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.

Future Development Costs (undiscounted) *(000s)*	**Proved Reserves**	**Proved Plus Probable Reserves**
2025	$66,773	$68,149
2026	$157,916	$158,855
2027	$217,740	$220,272
2028	$238,534	$242,218
2029	$116,792	$120,851
Remaining	$103,554	$1,055,273
Total	**$901,309**	**$1,865,618**

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 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.

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 in 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, 2024. Reserve amounts are stated, before deduction of royalties as of December 31, 2024, 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 35 MMboe for our interests in this area at year-end 2024.

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 6.9 MMboe to our interests in this area at year-end 2024.

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 245 MMboe to our interest in this area at year-end 2024.

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, 2024. 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		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross(1)	**Net**	**Gross(1)**	**Net**	**Gross(1)**	**Net**	**Gross(1)**	**Net**
Alberta	360	293	214	159	554	284	313	176
British Columbia	0	0	10	3	0	0	12	4
Saskatchewan	0	0	0	0	0	0	0	0
Total	360	293	224	162	554	284	325	180

(1) Gross wells include unit wells

Properties with no Attributed Reserves

The following table sets out our undeveloped land holdings as of December 31, 2024. Our undeveloped land holdings have no reserves attributed to them.

Undeveloped Land Holdings	**Undeveloped Acres**	
	Gross	**Net**
Alberta	358,591	238,838
British Columbia	9,801	4,864
Saskatchewan	0	0
Total	368,392	243,702

We expect that rights to explore, develop and exploit 3,898 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.