SINOPEC DAYLIGHT ENERGY LTD.
2022 ANNUAL SUMMARY RESERVE REPORT

Reserves Information

Disclosure of Reserves Data

The reserves data (the "Reserves Data") set forth below in this reserves report (the "Report") for Sinopec Daylight Energy Ltd. ("Sinopec Daylight" or the "Company") is based upon an independent evaluation of Sinopec Daylight's Core and Static assets and audit of Non-Core assets by McDaniel & Associates Consultants Limited ("McDaniel") with an effective date of December 31, 2022 contained in the McDaniel reserve report ("McDaniel Report") dated March 7, 2023. The opening reserves balances represent the reserves for Sinopec Daylight at December 31, 2021. 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 Sinopec Daylight's 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 Sinopec Daylight's 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 at December 31, 2022, Sinopec Daylight'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 Sinopec Daylight's working interest plus royalty interest before royalties paid and Net refers to Sinopec Daylight'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	6,009	5,162	-	-	80	93
Developed non-producing	905	672	51	50	53	42
Undeveloped	1,007	737	-	-	-	-
Total Proved	7,921	6,571	51	50	133	135
Probable	2,023	1,572	14	13	28	29
Total proved plus probable	**9,944**	**8,144**	**65**	**64**	**161**	**164**

Reserves	**Conventional Natural Gas**		**Coalbed Methane**		**Shale Gas**	
	Gross *(MMcf)*	**Net** *(MMcf)*	**Gross** *(MMcf)*	**Net** *(MMcf)*	**Gross** *(MMcf)*	**Net** *(MMcf)*
Proved						
Developed producing	85,572	78,137	169	161	118,571	104,398
Developed non-producing	10,652	9,058	-	-	11,781	10,448
Undeveloped	25,725	22,028	-	-	281,842	247,603
Total Proved	121,950	109,223	169	161	412,193	362,449
Probable	32,933	28,529	47	44	640,052	546,628
Total proved plus probable	154,884	137,752	216	205	1,052,245	909,077

Reserves Information

Reserves	Natural Gas Liquids		Total	
	Gross	Net	Gross	Net
	(MBbl)	*(MBbl)*	*(Mboe)*	*(Mboe)*
Proved				
Developed producing	10,137	7,659	50,279	43,364
Developed non-producing	1,016	738	5,764	4,753
Undeveloped	28,978	22,668	81,246	68,344
Total Proved	40,131	31,065	137,289	116,461
Probable	51,794	38,375	166,031	135,857
Total proved plus probable	**91,925**	**69,440**	**303,320**	**252,317**

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

(000s) discounted at	0%	5%	10%	15%	20%
Proved					
Developed producing	$222,941	$429,939	$430,933	$400,106	$367,996
Developed non-producing	$98,903	$75,619	$61,193	$51,277	$43,995
Undeveloped	$1,209,968	$778,637	$532,043	$378,969	$277,785
Total Proved	$1,531,812	$1,284,194	$1,024,168	$830,352	$689,776
Probable	$2,635,819	$1,535,725	$982,199	$673,068	$486,335
Total proved plus probable	**$4,167,631**	**$2,819,920**	**$2,006,367**	**$1,503,419**	**$1,176,111**

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

(000s) discounted at	0%	5%	10%	15%	20%
Proved					
Developed producing	$222,941	$429,939	$430,933	$400,106	$367,996
Developed non-producing	$98,903	$75,619	$61,193	$51,277	$43,995
Undeveloped	$1,126,799	$731,211	$503,700	$361,347	$266,455
Total Proved	$1,448,643	$1,236,769	$995,825	$812,730	$678,446
Probable	$2,041,120	$1,178,901	$751,687	$516,193	$375,410
Total proved plus probable	**$3,489,764**	**$2,415,670**	**$1,747,513**	**$1,328,923**	**$1,053,855**

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	$2,282,586	$339,317	$1,110,543	$56,814	$552,969	$222,941	$0	$222,941
Developed non-producing	$274,393	$52,596	$107,232	$15,662	$0	$98,903	$0	$98,903
Undeveloped	$3,881,141	$672,745	$1,222,693	$758,745	$16,990	$1,209,968	$83,169	$1,126,799
Total Proved	$6,438,119	$1,064,659	$2,440,468	$831,221	$569,959	$1,531,812	$83,169	$1,448,643
Probable	$7,612,170	$1,476,275	$2,686,811	$794,574	$18,689	$2,635,819	$594,699	$2,041,121
Total proved plus probable	**$14,050,289**	**$2,540,934**	**$5,127,279**	**$1,625,795**	**$588,648**	**$4,167,631**	**$677,868**	**$3,489,764**

(1) Abandonment, Decommissioning, Reclamation

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]	-$83,119	-$12.70
Heavy oil[1]	$1,096	$21.76
Tight oil[1]	$5,699	$42.14
Conventional Natural gas[2]	$234,686	$2.35
Coalbed methane	$93	$0.58
Shale Gas	$865,714	$2.40
Total Proved	**$1,024,168**	
Proved plus probable		
Light and medium crude oil[1]	-$132,411	-$16.32
Heavy oil[1]	$1,297	$20.33
Tight oil[1]	$6,654	$40.62
Conventional Natural gas[2]	$296,432	$2.34
Coalbed methane	$111	$0.54
Shale Gas	$1,834,284	$2.02
Total Proved plus probable	**$2,006,367**	

(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 take into account 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 2024, together with the following price forecasts supplied by McDaniel.

Year	West Texas Intermediate Crude Oil *($US/Bbl)*	Edmonton Light Crude Oil *($Cdn/Bbl)*	Natural Gas At AECO *($Cdn/MMbtu)*	Foreign Exchange *($US/$Cdn)*
2023	$80.00	$102.67	$4.00	0.75
2024	$76.50	$96.67	$4.08	0.75
2025	$75.43	$95.13	$4.16	0.75
2026	$74.28	$93.50	$4.24	0.75
2027	$75.77	$95.37	$4.33	0.75
2028	$77.29	$97.27	$4.42	0.75
2029	$78.83	$99.22	$4.50	0.75
2030	$80.41	$101.20	$4.59	0.75
2031	$82.02	$103.23	$4.69	0.75
2032	$83.66	$105.29	$4.78	0.75
2033	$85.33	$107.40	$4.88	0.75
2034	$87.04	$109.55	$4.97	0.75
2035	$88.78	$111.74	$5.07	0.75
2036	$90.55	$113.97	$5.17	0.75
2037 (escalation 2% thereafter)	$92.36	$116.25	$5.28	0.75

Weighted average historical prices realized by Sinopec Daylight for the year ended December 31, 2022 were $Cdn 6.34 per Mcf for natural gas, $Cdn 116.25 per Bbl for light oil ($Cdn 116.12 per Bbl for HVL) and $Cdn 40.11 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, 2021	7,651	2,697	10,348	42	10	52
Extensions and improved recovery	290	80	370	-	-	-
Technical revisions	42	(900)	(858)	(0)	1	1
Discoveries	112	36	148	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Expired Leases	-	-	-	-	-	-
Economic factors	629	109	738	9	3	12
Production	(803)	-	(803)	-	-	-
December 31, 2022	**7,921**	**2,023**	**9,944**	**51**	**14**	**65**

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, 2021	143	2,349	2,492	24,711	61,241	85,952
Extensions and improved recovery	-	-	-	784	255	1,039
Technical revisions	(22)	(2,326)	(2,348)	14,262	(11,345)	2,917
Discoveries	-	-	-	63	29	92
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Expired Leases	-	-	-	-	-	-
Economic factors	36	4	40	1,908	1,614	3,522
Production	(24)	-	(24)	(1,597)	-	(1,597)
December 31, 2022	**133**	**28**	**161**	**40,131**	**51,794**	**91,925**

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, 2021	115,020	54,104	169,124	303,414	798,900	1,102,314
Extensions and improved recovery	3,444	1,100	4,544	2,762	898	3,661
Technical revisions	(303)	(25,441)	(25,744)	104,734	(179,374)	(74,640)
Discoveries	2,849	1,406	4,255	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Expired Leases	-	-	-	-	-	-
Economic factors	14,192	1,765	15,957	24,013	19,628	43,640
Production	(13,253)	-	(13,253)	(22,730)	-	(22,730)
December 31, 2022	**121,950**	**32,933**	**154,884**	**412,193**	**640,052**	**1,052,245**

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, 2021	183	47	230	102,317	208,472	310,790
Extensions and improved recovery	-	-	-	2,108	668	2,777
Technical revisions	(112)	(42)	(154)	31,668	(48,712)	(17,044)
Discoveries	-	-	-	650	300	950
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Expired Leases	-	-	-	-	-	-
Economic factors	144	43	187	8,973	5,303	14,275
Production	(46)	-	(46)	(8,428)	-	(8,428)
December 31, 2022	**169**	**47**	**216**	**137,289**	**166,031**	**303,320**

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 46% of our total proved plus probable undeveloped reserves are attributed to proved undeveloped locations. The remaining 54% 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, 2022, $CDN 108.2 million was spent on capital expenditures including land and property acquisitions, net of dispositions. A portion of the 2023 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)***
2019	681	1,348	-	-	894	3,285
2020	-	1,192	-	-	-	-
2021	-	1,127	-	-	-	-
2022	109	1,007	-	-	-	-

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)*
2019	294	12,405	137,462	444,794	12,795	40,926
2020	-	22,499	-	280,454	-	24,182
2021	-	22,593	3,511	214,639	353	15,497
2022	242	25,725	2,762	281,842	418	22,668

Proved Undeveloped Reserves	Oil Equivalent	
	First Attributed (Mboe)	Total at Year-end (Mboe)
2019	37,330	121,759
2020	-	75,866
2021	939	56,163
2022	1,028	81,246

Approximately 89% of Sinopec Daylight's future capital associated with proved undeveloped reserves is scheduled for expenditure in 2023 to 2027, the remaining is associated with facilities and capitalized maintenance on existing wells. The major areas of development are the Wapiti and Brazeau (Rock Creek) properties, which 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 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)
2019	282	633	-	-	183	3,884
2020	-	1,044	-	-	-	6,790
2021	-	786	-	-	-	2,330
2022	37	373				

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)
2019	122	19,720	67,562	434,256	5,937	39,482
2020	-	31,374	-	739,332	-	55,879
2021	-	30,556	1,156	768,548	117	58,865
2022	90.6	10,972	898.132	606,170	133	49,306

Probable Undeveloped Reserves		
	Oil Equivalent	
	First Attributed	Total at Year-end
	(Mboe)	*(Mboe)*
2019	17,682	119,662
2020	-	192,164
2021	309	195,165
2022	335	125,537

Approximately 46% of Sinopec Daylight's future capital associated with proved plus probable undeveloped reserves is scheduled for expenditure in 2023 and 2027. The major areas of development are the Wapiti and Brazeau properties, which represent 99% of the total proved plus probable undeveloped future development costs and 99.3% of the total proved plus probable undeveloped reserves. The remaining proved plus probable undeveloped capital and reserves are associated with 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
2023	$98,480	$99,312
2024	$124,296	$125,988
2025	$80,276	$86,809
2026	$298,183	$302,102
2027	$118,980	$132,186
Remaining	$111,006	$879,398
Total	**$831,221**	**$1,625,795**

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. Sinopec Daylight 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, 2022. Reserve amounts are stated, before deduction of royalties as of December 31, 2022, 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 Sinopec Daylight'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. Sinopec Daylight 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. Sinopec Daylight 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 30 MMboe for our interests in this area at year-end 2022.

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 (Duvernay), 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 10 MMboe to our interests in this area at year-end 2022.

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. Sinopec Daylight has identified numerous additional Montney horizontal well opportunities in the PRA area. McDaniel has assigned total proved plus probable reserves of approximately 263 MMboe to our interest in this area at year-end 2022.

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, 2022. 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	366	297	228	171	584	296	322	184
British Columbia	0	0	10	3	3	2	12	4
Saskatchewan	0	0	1	0.5	0	0	0	0
Total	364	294	251	185	589	295	348	195

(1) Gross wells include unit wells

Properties with no Attributed Reserves

The following table sets out our undeveloped land holdings as of December 31, 2022. Our undeveloped land holdings have no reserves attributed to them.

Undeveloped Land Holdings	Undeveloped Acres	
	Gross	Net
Alberta	367,871	246,311
British Columbia	9,801	4,864
Saskatchewan	0	0
Total	377,672	251,175

We expect that rights to explore, develop and exploit 21,848 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. Sinopec Daylight calculates gross undeveloped acres by including undrilled spacing units in each lease or license where we have a working interest. 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 Sinopec Daylight's properties with no attributed reserves. Sinopec Daylight 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.