Report

Reserves Audit of Proved Reserves and Associated Income for Deal Assets, Mountrail County, ND as of October 1, 2021

Zephyr Energy plc

sproule.com

Sproule

November 19, 2021

Dr. Gregor Maxwell

Head of Subsurface

First Floor, Newmarket House
Market Street
Newbury, Berks
RG14 5DP, UK

RE: Reserves Audit of Proved Reserves and Associated Income for Deal Assets, Mountrail County, ND, as of October 1, 2021

Dear Dr. Maxwell:

At the request of Zephyr Energy plc ("Zephyr" or the "Company"), Sproule Incorporated (Sproule) has audited the Proved, crude oil, natural gas, and natural gas liquids (NGL) reserves and the associated future net revenue attributable to certain properties ("Deal Assets") Zephyr is acquiring located in the Williston Basin, Mountrail County, North Dakota as of October 1, 2021.

The scope and nature of Sproule's work is a review and examination of the specified reserves information for the purpose of expressing an opinion as to whether such reserves volumes, in the aggregate, are reasonable and have been estimated and presented in conformity with generally accepted petroleum engineering and evaluation principles. The Sproule examination included such tests and procedures as considered necessary under the circumstances to render the opinion set forth herein.

Sproule conducted certain tests and spot checks to confirm the adherence to the Society of Petroleum Engineers (SPE) Petroleum Resources Management System (PRMS) reserves reporting requirements and that the data flowing into the Zephyr reserves determination system were consistent with available records provided by Zephyr. A copy of the PRMS guidance is attached as Appendix C.

The Deal Assets covered in this audit includes 163 proved developed producing (PDP) wells, 5 proved non-producing (PNP) wells, 13 drilled uncompleted (DUC) wells, 47 proved undeveloped (PUD) locations, and 16 after payout (APO) wells for a total of 244 wells. Table 1 below summarizes the Zephyr assets in this audit.

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Table 1: Summary of Assets

Asset	Operator	Interest	Status	Total Lease Area, acres	Comments
Mountrail County, North Dakota	Whiting Petroleum Corporation	5.88% WI and 4.85% NRI	Producing	1,960	Production from Bakken and Three Forks formations at net 685 boepd

Net reserves, costs and revenues are those attributable to Zephyr, based on ownership, operating information, and other economic parameters provided by Zephyr. Future net revenue and discounted present value are on a before federal income tax (BFIT) basis. The results are summarized below by reserve status, with an effective date of October 1, 2021, in Table 2.

Table 2: Reserves Summary, Effective October 1, 2021

Reserves Category	Well Count	Net Oil Reserves (Mbbl)	Net Gas Reserves (MMcf)	Net NGL Reserves (Mbbl)	Discounted Cash Flow 10% (M$)
PDP	179[1]	1,097	1,823	281	30,458
PNP	5	48	71	11	1,213
DUC/PUD[1]	13	325	372	57	7,504
PUD	47	415	473	73	7,173
Total	**244**	**1,885**	**2,739**	**423**	**46,349**

*Note: Some columns may not add due to rounding

1. PDP well count includes 163 PDP wells and 16 After Payout (APO) wells. The APO are classified as proved developed producing, but do not convert to a paying interest. Only the abandonment costs have been included for these wells.

2. Drilled Uncompleted (DUC) wells have been classified as proved undeveloped (PUD) and are drilled wells with a range of remaining capital costs required to complete and bring on production. These have all been classified as PUD at the request of the Company, for simplicity

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Annual cash flow summaries by Reserve category and a oneline summary of all properties are included in Appendix A.

It should be understood that the Sproule reserves audit does not constitute a complete reserve study of the oil and gas properties of Zephyr. In the conduct of our audit, Sproule accepted and did not independently verify the accuracy and completeness of information and data furnished by Zephyr with respect to ownership interests, oil and gas production, historical costs of operation and development, development plans, product prices and energy content, market differentials, agreements relating to current and future operations and sales of production, and capital costs.

We have specifically identified the information and data upon which we did rely on for this audit. If, during our examination, something came to our attention which brought into question the validity or sufficiency of any of such information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or independently verified such information or data.

Sproule is an independent petroleum engineering consultancy comprised of petroleum engineers, geologists, and geoscientists. As an Auditor and Reviewer responsible for preparing this audit report, I meet the requirements of objectivity for Reserve Auditors as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers (SPE).

Please be advised that, based upon the foregoing analysis, in Sproule's opinion the above estimates of Zephyr's proved oil, gas, and NGL reserves are, in the aggregate, reasonable and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles as set forth in the SPE Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information.

The Zephyr reserves determinations do not contain any significant misrepresentations that would materially change or alter the estimated reserve volumes or values presented in this audit report. The reserve estimates conform to the PRMS reserves regulations and requirements.

STATEMENT OF RISK

The accuracy of reserve audits is always subject to uncertainty. However, while these estimates are prepared with reasonable care, unforeseen changes in future well and field performance, the impact of offset drilling, changes in market conditions and sales contracts, along with changes in operating conditions and associated costs may all impact the actual ability to recover the reserves estimated in this report and, subsequently, generate the estimated cash flow. As a result, any use of or reliance on this report needs to recognize such risks and uncertainty, and Sproule makes no warranties concerning the ability to realize stated reserves or future estimated revenue in this report.

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Neither Sproule nor any of its employees have any interest in the subject properties. Neither the employment to conduct this study nor the compensation for this study was contingent on Sproule's estimates of reserves and future income. This report has been prepared for the sole and exclusive use of Zephyr. Use by other parties, or for purposes other than those expressed by Zephyr, is not authorized without written consent by Sproule. Any third party who receives or views this report may not rely on the report as their sole source of information. Sproule assumes no liability for reliance on this report by anyone other than Zephyr. This report, and its use, remain subject to all the terms and conditions contained in the Master Services Consulting Agreement, including Zephyr's obligation to indemnify Sproule for any actions which may be taken by any third party with respect to this report and Sproule's total aggregate liability in relation to provision of its serves and this report as set out therein.

It has been Sproule's pleasure to prepare this audit for Zephyr. If you should have any questions concerning this analysis, please feel free to contact us.

Sincerely,

Nov.19,2021
Jeffery B. Aldrich, L.P.G.
Senior Geoscientist

Nov. 19, 2021
John Seidle, P.E.
Senior Engineer

Jeffery B. Aldrich, L.P.G.
Senior Geoscientist

John Seidle, Ph.D., P.E.
Senior Petroleum Engineer

The following Responsible Member of Sproule Incorporated certifies that our internal quality control process has been completed in accordance with our Professional Practice Management Plan.

Meghan Klein

Nov. 19, 2021

Meghan Klein, P. Eng.
Senior Manager, Engineering

Nov. 19, 2021

Alec Kovaltchouk, P. Geo.
VP, Geoscience

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Certificate of Qualifications

Jeffrey Aldrich, L.P.G.

I, Jeffrey B. Aldrich, Senior Geoscientist of Sproule, 730 17th St., Denver, Colorado, USA, declare the following:

1. I hold the following degree:
    a. B.S. Geology (1977) Vanderbilt University, Nashville, TN, USA
    b. M.S. Geology (1983) Texas A&M University, College Station, Texas, USA

2. I am a licensed professional:
    a. Licensed Professional Geoscientist (P.G.) Louisiana, USA #394
    b. Licensed Professional Geoscientist (P.G.) Texas, USA # 15140
    b. Certified Petroleum Geologist (C.P.G) The American Association of Petroleum Geologists #6254

3. I am a member of the following professional organizations:
    a. American Association of Petroleum Geologists (AAPG)
    b. Society of Petroleum Engineers (SPE)

4. I am a qualified reserves evaluator and reserves auditor as defined in:
    a. the "Canadian Oil and Gas Evaluation Handbook" as promulgated by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and,
    b. the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" as promulgated by the Society of Petroleum Engineers and incorporated into the "Petroleum Resource Management System" (SPE-PRMS).

5. My contribution to the report entitled "Reserves Audit of Proved Reserves and Associated Income for Deal Assets, Mountrail County, ND as of October 1, 2021" is based on my geoscience knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule.

6. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of Zephyr Energy plc.

Nov 19,2021

Jeffrey Aldrich, L.P.G.

Sproule

Certificate of Qualifications

John Seidle, P.E.

I, John Seidle, Senior Reservoir Engineer of Sproule, 730 17th St., Denver, Colorado, USA, declare the following:

1. I hold the following degrees:
    a. B.S. Aeronautical Engineering (1972) University of Colorado, USA
    b. M.S. Aeronautical Engineering (1973) Stanford, USA
    c. Ph.D. Mechanical Engineering (1981) University of Colorado, USA

2. I am a registered professional:
    a. Professional Registered Engineer (P.E.), Colorado, USA
    b. Professional Registered Engineer (P.E.), Oklahoma, USA
    c. Professional Registered Engineer (P.E.), Wyoming, USA

3. I am a member of the following professional organizations:
    a. Society of Petroleum Engineers (SPE)
    b. Society of Petroleum Evaluation Engineers (SPEE)

4. I am a qualified reserves evaluator and reserves auditor as defined in:
    a. the "Canadian Oil and Gas Evaluation Handbook" as promulgated by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and,
    b. the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" as promulgated by the Society of Petroleum Engineers and incorporated into the "Petroleum Resource Management System" (SPE-PRMS).

5. My contribution to the report entitled "Reserves Audit of Proved Reserves and Associated Income for Deal Assets, Mountrail County, ND as of October 1, 2021" is based on my engineering knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule.

6. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of Zephyr Energy plc.

John P. Seidle

John Seidle, P.E.

Sproule

Certificate of Qualification

Meghan M. Klein, P.Eng.

I, Meghan M. Klein, Senior Manager, Engineering of Sproule, 900, 140 Fourth Avenue SW, Calgary, Alberta, declare the following:

1. I hold the following degree:
   a. B.A.Sc. Geological Engineering (2005), University of Waterloo, Waterloo, ON, Canada

2. I am a registered professional:
   a. Professional Engineer (P.Eng.), Province of Alberta, Canada

3. I am a member of the following professional organizations:
   a. Association of Professional Engineers and Geoscientists of Alberta (APEGA)
   b. Society of Petroleum Engineers (SPE)

4. I am a qualified reserves evaluator and reserves auditor as defined in:
   a. the "Canadian Oil and Gas Evaluation Handbook" as promulgated by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and,
   b. the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" as promulgated by the Society of Petroleum Engineers and incorporated into the "Petroleum Resource Management System" (SPE-PRMS).

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6. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of Zephyr Energy plc.

Meghan Klein

Nov. 19, 2021

Meghan M. Klein, P.Eng.

Sproule

Certificate of Qualification

Alec Kovaltchouk, P.Geo.

I, Alec Kovaltchouk, VP, Geoscience of Sproule, 900, 140 Fourth Avenue SW, Calgary, Alberta, declare the following:

1. I hold the following degree:
   a. M.Sc. Geochemistry (1981) University of Lviv, Lviv, Ukraine

2. I am a registered professional:
   a. Professional Geoscientist (P.Geo.), Province of Alberta, Canada

3. I am a member of the following professional organizations:
   a. Association of Professional Engineers and Geoscientists of Alberta (APEGA)
   b. Canadian Society of Petroleum Geologists (CSPG)

4. I am a qualified reserves evaluator and reserves auditor as defined in:
   a. the "Canadian Oil and Gas Evaluation Handbook" as promulgated by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and,
   b. the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" as promulgated by the Society of Petroleum Engineers and incorporated into the "Petroleum Resource Management System" (SPE-PRMS).

5. My contribution to the report entitled "Reserves Audit of Proved Reserves and Associated Income for Deal Assets, Mountrail County, ND as of October 1, 2021" is based on my geological knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule.

6. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of Zephyr Energy plc.

Nov. 19, 2021

Alec Kovaltchouk, P.Geo.

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ASSET OVERVIEW

Zephyr has working interest in a leasehold net acreage of 1,960 acres, located in Mountrail County and operated by Whiting Petroleum Corporation. The acreage includes 163 PDP wells (67%), 5 PNP wells (2%), 13 DUC/PUD wells (5%), 47 PUD locations (19%), and 16 APO/PDP wells (7%). Of the 244 wells, 176 of them (72%) target the Middle Bakken Formation and 68 of them (28%) target the Three Forks Formation. Lease details provided by Zephyr appeared reasonable and were accepted without further review.

The average working interest (WI) for all wells is 5.88% and the average net royalty interest (NRI) for all wells is 4.85%. For the PDP, DUC/PUD, and PNP wells, the WI ranges from 0.14193% to 28.218799% and the RI ranges from 0.11782% to 24.498929%. For the PUD wells, the WI ranges from 0.13756% to 13.412599% and the RI ranges from 0.11463% to 11.06883%.

In terms of future development, the operator plans to return all 5 PNP wells to production in November 2021, complete the 13 DUC/PUD wells and turn them to production by April 2022, and develop the 47 PUD wells by 2024. Specifically, the operator plans to develop 4 PUD wells in 2021, 20 in 2022, 13 in 2023, and the final 10 PUD wells in 2024. Thus, all PNP wells, DUC wells, and PUD wells will be developed by 2026, within the 5-year window allowed for such locations. No value has been assigned to the APO/PDP entities for this audit as the wells do not revert to a paying interest. Abandonment for these locations has been included in the PDP economics.

GEOLOGIC AUDIT

The assets are located in Mountrail County, ND within the Williston Basin (Figure 1). The Williston Basin itself is a large intra-cratonic basin and the Middle Bakken and Three Forks target reservoirs are late Devonian in age (Figures 2 and 3). These formations were deposited in a basin that displayed relatively even subsidence rates at the time of deposition. The asset area displays limited structural complexity. The Middle Bakken reservoir consists of a dolomitic sandstones and siltstones and is largely homogenous. In the asset area, it is around 40-50 feet thick with average porosities of 6 percent and water saturations of 30-40 percent. The Three Forks reservoir is thinner in this location (less than 40 feet) than the Middle Bakken reservoir and predominantly consists of dolomitic siltstones interbedded with mudstones. It has similar porosities as the Middle Bakken reservoir, but is more heterogenous. Both reservoirs were deposited in shallow marine tidal depositional environments. The reservoir quality for both reservoirs is poor (only up to 0.2 mD) and as a result, the reservoir has to be developed by horizontal wells that are hydraulically stimulated to deliver economical flow rates and recoveries. The Three Forks reservoir has a higher water saturation than the Middle Bakken reservoir and development wells typically have higher produced water cuts. The reservoir is typically over pressured at initial conditions (approximately 0.7psi/ft) and reservoir fluids are light oils (40-44 API) which have initial gas oil ratios less than 1,000 scf/bbl. The fluids are sourced from the bounding Upper and Lower Bakken shales which are highly productive source rocks. Migration distances from these source rocks is likely to be very limited.

The initial Williston Basin discovery wells were made in the 1950's but significant drilling of the tight oil 'Bakken' play did not begin in earnest until 2008. Over 4,000 horizontal wells have been drilled in Mountrail County in the intervening period and the area is still actively drilled today. At the beginning of 2021, the horizontal wells in Mountrail County, targeting the Bakken play, had produced 900 MMbbl of oil and 1 TCF of gas from horizontal wells in the Middle Bakken and the deeper Three Forks reservoirs. The target assets form a small subset of these development wells and the potential development locations represent some of the remaining infill drilling locations of the mature Sanish Field.

Figure 1: Location of the Bakken Total Petroleum System (TPS), the Productive Outline of Bakken within the Williston Basin and the Location of the Asset Area, (from USGS)

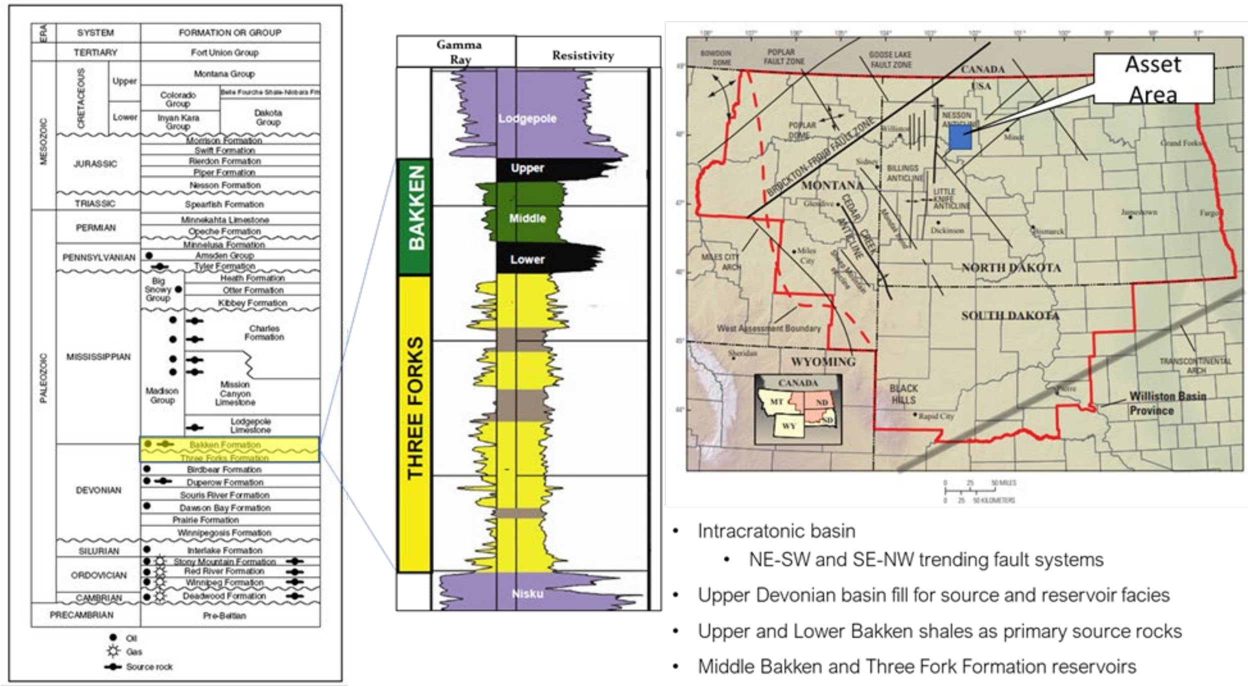

Figure 2: Williston Basin Schematic Stratigraphy and Location (provided by Zephyr)

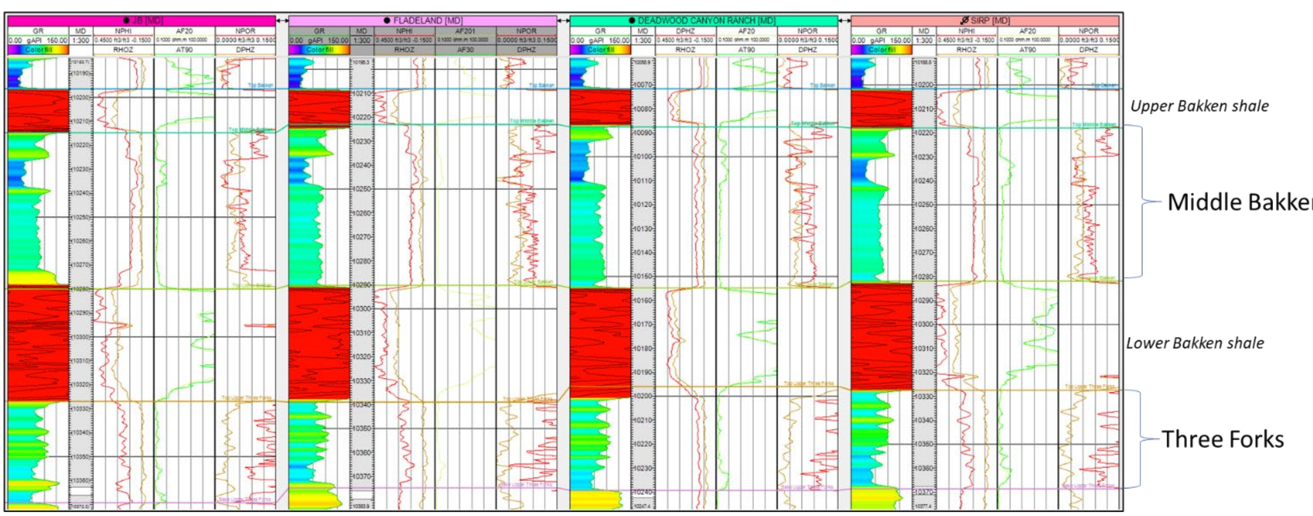

Figure 3: Asset Type Wells Showing the Two Targeted Reservoirs (provided by Zephyr)

Since the initial horizontal drilling began in the basin, the completion technology applied to stimulate these wells has developed considerably. In the asset area, wells typically have approximately10,000 feet horizontal sections that host up to 50 separate fracture stages. Fluid volumes pumped to create the artificial fracture network can range from 200,000 to 400,000 barrels of water with 8 million lbs. of sand used as proppant to maintain fracture aperture. These are common completion styles for the asset area. The wells are drilled commonly more than 600 feet apart within unitized Drilling Spacing Units (DSUs) that allow for efficient field development across diverse lease holdings. The DSUs that give approval for well spacing and permits to drill are approved by the state regulatory authority, the North Dakota Oil and Gas Division of the Department of Mineral Resources.

Sproule reviewed the Zephyr’s geologic work for best practices and conformity with published industry information on the Middle Bakken and did not build an independent geologic model, review formation picks on logs, review seismic, or create maps. All information provided by Zephyr was verified by Sproule using publicly available data and confirmed for reasonableness. Based on the analysis of the data provided by Zephyr, it is Sproule's opinion that the parameters and geologic cut-offs used for the Tiers are within reason. In addition to this analysis, Sproule investigated future development locations (PUD’s) regarding the geologic tiers and reservoir quality. Sproule concurs that these locations were picked within reason and used the aforementioned petrophysical cut-offs and parameters.

UNDEVELOPED LOCATIONS

Oil production forecasts for undeveloped locations and drilled uncompleted (DUC) wells were generated with type wells constructed from analog wells in this area. Technically recoverable oil volumes for these wells were estimated with decline curve analysis and normalized by lateral length. Normalized oil recovery volumes were then ranked and P90, P50, and P10 values determined. Multiplying these values by the planned lateral length of a given PUD yielded the three technically recoverable oil volumes for the location. Combining the average Arps decline rate and “b” value from the analog wells and a terminal decline rate of 8 %/yr, the initial Arps rate was adjusted to obtain the P90, P50, and P10 recoverable oil volumes for a given location. Gas and water production were forecasted from the oil type wells and specified GOR (gas-oil ratio) and WOR (water-oil ratio) profiles. Natural gas liquid (NGL) production was forecasted using the gas profile and a yield of 138 bbl/mmcf flat. After reviewing this process estimating production from undeveloped locations, Sproule finds Zephyr’s methodology and values reasonable. The current operator’s plans for future well locations were reviewed, and they meet general industry standards. There may be a limited number of future PUD wells that perform less optimally than forecasted; however, the economic impact of this is deemed to be de minimis to this evaluation.

FORECASTS

The producing (PDP) well forecasts and PNP well forecasts were generated using decline curve analysis (DCA), with the oil and gas phases forecasted separately for each well. Zephyr imposed a terminal decline rate of 8 %/yr on the declines. The PNP forecast was slipped in time to coincide with the scheduled return to production of the given well.

Water forecasts were also developed for each well as part of calculating water operating expenses for the economic evaluation.

NGL yields were estimated using the gas profile and a yield of 138 bbl/MMcf flat.

The forecast parameters were deemed to be reasonable.

CAPITAL COSTS

Capital costs included drilling and completion of the wells and artificial lift. Wells in this region of the Williston basin typically flow naturally for a brief period then ESP's are used to lift the fluids. As fluid production declines, typically after a few months to a year, the ESP's are replaced with rod pumps for the duration of the well lifetime. Capital costs for the different Reserves categories are summarized in Table 3 below. The capital allocation after 18 months captures the artificial lift costs. Capital costs were not escalated until 2025. Beginning in 2025, capital costs were escalated at a rate of 2%/yr until they had doubled, in 2059, after which time they were held constant for the duration of the project life.

The forecast capital costs were deemed to be reasonable.

Table 3: Well Gross Capital Costs by Reserve Category, M$

Investment	PDP	PNP	PUD-DUC	PUD	PDP-APO
Drill & Completion	0	0	5226 - 7550	4900 - 7550	0
Artificial lift – 18 months	300	100	191 - 421	300 - 421	0
Abandonment	160	160	160	160	160

OPERATING EXPENSES

Well operating expenses have fixed and variable components. Fixed OPEX varies by Reserve category. Gross operating expenses for the PDP's varies between 3,400 and 26,200 $/well/month, for the PNP's between 4,300 and 11,600 $/well/month, the APO/PDPs are a constant 7,900 $/well/month. The DUC/PUD gross OPEX stairsteps down in five annual intervals from an initial OPEX of 25,000 $/well/month to 20,000 then 15,000, followed by 12,700, before reaching the final OPEX of 7,900 $/well/month for the duration of the well's life.

Variable operating expenses include a gross gas OPEX of 4.27 $/mcf and a gross water OPEX of 1.45 $/bbl.

Similar to capital costs, operating expenses were not escalated until 2025 at which time they were escalated at a rate of 2%/yr until doubling in 2059. Operating expenses were held constant thereafter for the life of the project life.

Severance tax on oil and NGL production is initially 10%, dropping to 5% once oil and NGL production falls below 28 or 32 bpd depending on the well. Gas severance tax is 0.0522 $/mcf flat.

The forecast operating expenses were deemed to be reasonable.

HYDROCARBON PRICES

Crude oil, natural gas, and NGL prices utilized in this audit are summarized in Table 4 below. The NGL price is 40% of the oil price. No differentials were applied to gas and NGL prices. The gas BTU factor is 0.976, shrinkage is 10.6%.

Table 4: Oil & Gas Price Forecast

Year	Oil ($/bbl)	Oil Diff ($/bbl)	Oil Realized ($/bbl)	Gas ($/mmbtu)	NGL ($/bbl)
2021	76.00	-6.50	69.50	5.00	30.40
2022	71.00	-6.50	64.50	4.00	28.40
2023	68.00	-6.50	61.50	3.50	27.20
2024	66.00	-6.50	59.50	3.25	26.40

Escalated at 2%/yr thereafter until price doubles, then held flat

APPENDIX A: ONE LINE SUMMARY AND CASHFLOWS

ZEPHYR ENERGY LLC
PROVED RESERVES ADUIT
MOUNTRAIL COUNTY, ND
ONELINE SUMMARY
EFFECTIVE 10/2021

Well	Res Cat	Reservoir	Location	WI	NRI	Life (Years)	Start Date	Gross Oil (Mbbl)	Gross Gas (MMCF)	Gross NGL (Mbbl)	Net Oil (Mbbl)	Net Gas (MMCF)	Net NGL (Mbbl)	Net Revenue (M$)	Taxes (M$)	Operating Expense (M$)	Investment and P&A Cost (M$)	Undisc. NCF (M$)	Discounted NCF @ 10% (M$)	Ultimate Oil (Mbbl)	Ultimate Gas (MMCF)	Cum Oil (Mbbl)	Cum Gas (MMCF)
PROVED DEVELOPED PRODUCING																							
ABBOTT 11-18H	PDP	BAKKEN	18 153N 91W	0.004	0.003	14.83	01/2021	56.4	75.7	10.4	0.2	0.2	0.0	14.6	0.7	8.3	0.8	4.8	3.6	574.3	79.6	517.8	3.9
ANDERSON 11-7-2H	PDP	BAKKEN	7-18 154N 92W	0.219	0.177	20.92	01/2021	135.7	314.6	43.4	24.1	49.9	7.7	2,027.6	125.3	862.9	50.0	989.4	687.7	308.8	341.4	173.1	26.8
ANDERSON 11-7-2TFH	PDP	THREE FORKS	7-18 154N 92W	0.219	0.177	23.92	10/2020	121.9	271.8	37.5	21.6	43.1	6.7	1,836.0	104.8	761.3	53.0	916.9	603.7	224.5	292.0	102.6	20.3
ANDERSON 11-7TFH	PDP	THREE FORKS	7 154N 92W	0.219	0.177	9.50	01/2021	31.0	30.6	4.2	5.5	4.9	0.7	387.6	18.8	225.3	40.2	103.4	99.9	238.0	33.5	207.0	2.9
ANDERSON 21-7H	PDP	BAKKEN	7 154N 92W	0.219	0.177	19.42	01/2021	101.4	92.6	12.8	18.0	14.7	2.3	1,331.6	68.0	605.7	49.0	609.0	404.7	426.0	96.8	324.6	4.2
ANDERSON 41-7H	PDP	BAKKEN	7 154N 92W	0.219	0.177	29.17	01/2021	233.2	262.4	36.2	41.4	41.6	6.4	3,270.3	237.2	1,054.9	58.5	1,919.6	1,058.5	518.8	273.4	285.6	11.0
ANDERSON 41-7HU	PDP	BAKKEN	7-18,8-17 154N 92W	0.119	0.096	22.92	10/2020	165.0	331.1	45.7	15.9	28.5	4.4	1,313.9	85.1	510.0	28.2	690.5	463.1	359.2	359.2	194.2	28.2
ANDERSON 41-7TFH	PDP	THREE FORKS	7-18 154N 92W	0.219	0.177	26.83	01/2021	173.7	139.5	19.2	30.8	22.1	3.4	2,302.1	154.7	691.1	56.3	1,400.1	896.0	353.6	152.0	179.9	12.5
ARNDT FEDERAL 34-35H	PDP	BAKKEN	35 154N 91W	0.134	0.111	17.92	01/2021	49.9	555.2	76.6	5.5	54.9	8.5	813.7	33.6	488.8	28.9	262.4	194.3	450.7	593.3	400.8	38.1
BEHR 11-34H	PDP	BAKKEN	34 154N 91W	0.134	0.111	28.58	01/2021	129.3	567.4	78.3	14.3	56.1	8.7	1,484.4	75.9	579.1	35.9	793.4	437.2	1,257.8	590.9	1,128.5	23.5
BENDER 14-6H	PDP	BAKKEN	6 153N 92W	0.188	0.152	21.42	04/2020	76.9	80.3	11.1	11.7	10.9	1.7	884.7	42.8	376.2	43.7	422.0	280.1	206.2	83.3	129.3	3.0
BRAAFLAT 11-11H	PDP	BAKKEN	11 153N 91W	0.004	0.003	30.50	01/2021	160.5	372.8	51.4	0.5	1.1	0.2	45.6	2.7	15.6	1.1	26.2	14.2	1,003.4	386.9	842.9	14.2
BRAAFLAT 21-11TFH	PDP	THREE FORKS	11 153N 91W	0.004	0.003	22.75	01/2021	74.1	83.1	11.5	0.2	0.2	0.0	18.3	0.9	7.6	0.9	8.8	5.7	412.0	86.5	337.9	3.4
BROOKBANK STATE 41-16XH	PDP	BAKKEN	16 154N 92W	0.020	0.016	18.50	01/2021	113.1	121.7	16.8	1.9	1.8	0.3	138.1	9.0	55.6	4.5	69.0	50.3	483.4	132.1	370.3	10.5
BROOKBANK STATE 42-16TFX	PDP	THREE FORKS	16 154N 92W	0.020	0.016	27.00	01/2021	152.0	140.0	19.3	2.5	2.1	0.3	192.3	11.9	64.4	5.2	110.7	63.3	464.6	151.3	312.6	11.3
BROOKBANK STATE 44-9TFX	PDP	THREE FORKS	9 154N 92W	0.020	0.016	22.08	01/2021	120.6	144.4	19.9	2.0	2.1	0.3	153.3	8.5	67.3	4.7	72.7	45.5	328.9	150.5	208.3	6.1
BROWN 41-28-2XH	PDP	BAKKEN	28 154N 91W	0.033	0.028	35.17	01/2021	232.7	325.8	45.0	6.4	8.0	1.2	530.4	35.2	134.6	10.0	350.7	176.4	496.4	338.5	263.7	12.7
BROWN 41-28XH	PDP	BAKKEN	28 154N 91W	0.033	0.028	14.92	01/2021	32.9	33.0	4.6	0.9	0.8	0.1	65.9	3.2	33.3	6.7	22.7	18.6	446.3	36.3	413.4	3.3
BROWN 42-28XH	PDP	BAKKEN	28 154N 91W	0.033	0.028	17.33	01/2021	68.8	123.6	17.1	1.9	3.0	0.5	149.2	7.8	60.9	7.1	73.3	56.8	447.3	135.6	378.5	11.9
CARKUFF 13-14H	PDP	BAKKEN	14 154N 92W	0.292	0.245	18.83	01/2021	79.1	64.8	8.9	19.4	14.2	2.2	1,414.9	69.6	628.2	64.2	653.0	450.3	265.8	64.8	186.7	0.0
CARL KANNIANEN 13-7XH	PDP	BAKKEN	7 153N 91W	0.002	0.002	18.42	10/2020	74.7	489.9	67.6	0.1	0.8	0.1	14.8	0.6	8.6	0.5	5.1	3.5	289.9	513.4	215.2	23.5
CARL KANNIANEN 21-4H	PDP	BAKKEN	4 153N 91W	0.010	0.008	22.92	01/2021	76.8	383.4	52.9	0.6	2.8	0.4	66.0	2.9	30.0	2.3	30.8	19.1	442.2	401.1	365.4	17.7
CARL KANNIANEN 24-33H	PDP	BAKKEN	33 154N 91W	0.020	0.017	9.83	01/2021	30.9	93.6	12.9	0.5	1.4	0.2	45.3	2.1	23.7	3.7	15.7	14.4	269.0	104.4	238.1	10.8
CURT BRAAFLAT 11-11H	PDP	BAKKEN	11 153N 91W	0.004	0.003	29.08	01/2021	137.2	318.3	43.9	0.4	0.9	0.1	38.8	2.0	13.1	1.0	22.6	12.7	502.2	332.1	365.0	13.8
DARYL LOCKEN 21-22H	PDP	BAKKEN	22 153N 91W	0.006	0.005	26.17	01/2021	117.8	206.0	28.4	0.6	1.0	0.1	50.0	2.9	16.6	1.5	28.9	18.1	661.9	218.6	544.1	12.7
DEAL 43-28TFH	PDP	THREE FORKS	28 154N 91W	0.066	0.055	18.50	01/2021	76.3	118.0	16.3	4.2	5.8	0.9	328.9	15.7	160.2	14.5	138.5	95.3	258.0	123.2	181.6	5.3
DOMASKIN 21-20HU	PDP	BAKKEN	17-18 / 19-20 154N-92W	0.078	0.063	18.58	01/2021	104.3	246.3	34.0	6.6	13.9	2.1	549.6	31.7	278.7	17.0	222.1	157.4	241.1	266.8	136.9	20.5
DOMASKIN 24-17TFHU	PDP	THREE FORKS	17-18 / 19-20 154N-92W	0.078	0.063	16.08	10/2020	81.5	130.5	18.0	5.1	7.3	1.1	395.8	22.3	200.9	16.1	156.6	117.8	165.8	143.0	84.4	12.5
DOMASKIN 31-20HU	PDP	BAKKEN	16-17 / 20-21 154N-92W	0.015	0.012	16.83	10/2020	103.6	240.0	33.1	1.3	2.6	0.4	105.2	6.6	45.3	3.2	50.0	38.6	222.5	267.7	118.9	27.8
DOMASKIN 34-17TFHU	PDP	THREE FORKS	16-17 / 20-21 154N-92W	0.015	0.012	15.42	01/2021	80.1	241.7	33.4	1.0	2.7	0.4	86.1	4.8	45.7	3.2	32.4	25.4	205.1	267.8	125.0	26.1
FLADELAND 11-10H	PDP	BAKKEN	10 154N 92W	0.107	0.087	21.17	01/2021	94.9	210.1	29.0	8.3	16.4	2.5	698.5	32.8	317.8	24.4	323.5	209.3	513.8	220.1	418.9	10.0
FLADELAND 12-10H	PDP	BAKKEN	10 154N 92W	0.107	0.087	23.92	11/2021	119.4	76.0	10.5	10.4	5.9	0.9	767.7	42.7	278.0	25.9	421.1	253.6	633.6	76.0	514.3	0.0
FLADELAND 12-18H	PDP	BAKKEN	18 153N 91W	0.004	0.003	20.58	01/2021	72.0	340.5	47.0	0.2	1.0	0.2	25.5	1.1	13.4	0.9	10.0	6.7	585.8	355.5	513.9	15.0
FLADELAND 12-20TFH	PDP	THREE FORKS	20 153N 91W	0.005	0.004	12.83	01/2021	38.7	27.8	3.8	0.2	0.1	0.0	11.6	0.6	6.3	1.0	3.8	3.2	313.0	29.6	274.3	1.8
FLADELAND 13-10H	PDP	BAKKEN	10 154N 92W	0.107	0.087	23.42	01/2021	104.2	64.8	8.9	9.1	5.1	0.8	667.9	33.0	247.0	25.9	362.1	224.5	322.4	67.6	218.2	2.7
FLADELAND 13-10HU	PDP	BAKKEN	15-16/(S/2) 9-10 154N-92W	0.030	0.024	23.08	01/2021	176.6	241.8	33.4	4.3	5.2	0.8	331.4	22.7	122.0	7.0	179.6	121.7	426.0	267.6	249.4	25.8
FLADELAND 13-10TFH	PDP	THREE FORKS	10-11 154N 92W	0.107	0.087	34.42	10/2020	436.5	840.5	116.0	38.1	65.6	10.1	3,267.4	254.8	951.6	32.2	2,028.9	1,131.3	595.0	897.5	158.5	57.0
FLADELAND 13-18TFH	PDP	THREE FORKS	18 153N 91W	0.004	0.003	22.00	01/2021	68.8	87.8	12.1	0.2	0.3	0.0	18.5	0.9	7.9	1.0	8.7	5.7	253.5	91.7	184.6	3.8
FLADELAND 14-18WH	PDP	BAKKEN	18 153N 91W	0.004	0.003	23.00	01/2021	76.2	331.7	45.8	0.3	1.0	0.2	26.6	1.2	13.2	1.0	11.2	7.2	362.3	345.4	286.0	13.8
FLADELAND 41-9H	PDP	BAKKEN	9 154N 92W	0.010	0.008	12.50	01/2021	42.0	26.7	3.7	0.3	0.2	0.0	23.9	1.2	12.2	2.0	8.6	7.4	284.3	28.6	242.3	1.9
FLADELAND 42-9TFH	PDP	THREE FORKS	9 154N 92W	0.011	0.009	23.67	01/2021	145.1	125.5	17.3	1.3	1.0	0.2	100.9	5.8	40.0	2.8	52.3	31.7	301.9	131.0	156.8	5.5
FLADELAND 43-9H	PDP	BAKKEN	9 154N 92W	0.010	0.008	3.08	01/2021	10.4	13.8	1.9	0.1	0.1	0.0	6.3	0.3	3.7	1.6	0.7	0.9	410.8	17.3	400.4	3.5
FLADELAND 44-9-2H	PDP	BAKKEN	8-9 154N-92W	0.010	0.008	17.33	01/2021	94.0	667.2	92.1	0.8	4.9	0.8	90.8	5.0	48.4	2.2	35.2	27.4	252.3	737.7	158.3	70.5
FLADELAND 44-9-3H	PDP	BAKKEN	8-9 154N-92W	0.010	0.008	20.58	01/2021	133.0	452.4	62.4	1.1	3.3	0.5	100.9	6.2	45.0	2.3	47.4	33.7	317.2	494.7	184.2	42.3
FLADELAND 44-9H	PDP	BAKKEN	9 154N 92W	0.010	0.008	1.00	01/2021	2.0	4.6	0.6	0.0	0.0	0.0	1.4	0.1	1.0	1.6	-1.3	-1.2	327.6	7.5	325.6	2.9
HANSEN 12-20H	PDP	BAKKEN	20 153N 91W	0.005	0.004	29.00	01/2021	140.9	330.1	45.6	0.6	1.3	0.2	53.5	3.0	19.2	1.4	29.9	16.8	701.2	343.4	560.3	13.3
HANSEN 13-20TFX	PDP	THREE FORKS	20 153N 91W	0.005	0.004	27.33	01/2021	205.7	294.7	40.7	0.8	1.1	0.2	68.6	4.8	24.7	1.3	37.9	21.2	525.1	306.1	319.4	11.4
HANSEN 14-20TFX	PDP	THREE FORKS	20 153N 91W	0.005	0.004	25.50	01/2021	114.6	129.3	17.8	0.5	0.5	0.1	36.8	1.9	13.6	1.3	20.0	12.0	356.7	134.8	242.2	5.4
HANSEN 14-20XH	PDP	BAKKEN	20 153N 91W	0.005	0.004	30.08	01/2021	195.6	472.4	65.2	0.8	1.7	0.3	71.8	4.7	25.3	1.4	40.5	22.0	694.4	493.3	498.8	20.9
HANSEN 21-20H	PDP	BAKKEN	20 153N 91W	0.005	0.004	34.58	01/2021	233.9	1,372.5	189.4	1.0	5.3	0.8	118.3	7.1	48.9	1.6	60.8	31.1	605.7	1,421.7	371.9	49.2
HARTSTROM 24-33H	PDP	BAKKEN	33 154N 91W	0.020	0.017	25.33	01/2021	157.5	258.3	35.6	2.7	4.0	0.6	219.3	14.0	73.2	5.1	127.0	81.7	398.8	276.4	241.3	18.1
HARVEY TTT 41-4HU	PDP	BAKKEN	4-9 / 3-10 154N-91W	0.007	0.005	26.67	01/2021	276.0	448.1	61.8	1.5	2.2	0.3	119.1	8.9	34.9	1.7	73.5	49.3	579.0	498.3	303.0	50.3
HAUGE 44-36-2HU	PDP	BAKKEN	19-30-31/24-25-36 153N-90-91W	0.031	0.025	28.67	01/2021	177.6	196.1	27.1	4.5	4.4	0.7	345.1	22.9	94.6	8.4	219.2	137.8	387.7	213.0	210.1	16.8
HEIPLE 11-3H	PDP	BAKKEN	3 154N 92W	0.142	0.116	25.50	01/2021	143.3	134.2	18.5	16.6	13.9	2.1	1,266.2	76.9	452.0	35.9	701.5	410.6	557.9	139.7	414.6	5.5
HEIPLE 14-3XH	PDP	BAKKEN	3 154N 92W	0.124	0.101	15.33	01/2021	74.8	73.3	10.1	7.6	6.7	1.0	549.7	31.6	260.1	25.7	232.2	180.0	502.4	79.7	427.7	6.3
HOLLINGER 11-14TFH	PDP	THREE FORKS	14 154N 92W	0.292	0.245	21.33	01/2021	82.2	88.9	12.3	20.1	19.5	3.0	1,529.7	73.9	642.7	68.1	744.9	491.2	277.3	93.2	195.1	4.3
HOLLINGER 21-14TFH	PDP	THREE FORKS	14 154N 92W	0.292	0.245	16.08	01/2021	53.8	52.8	7.3	13.2	11.6	1.8	964.3	46.7	498.0	60.5	359.1	272.3	251.5	55.6	197.7	2.8
IVERSON 11-14-2H	PDP	BAKKEN	14-23 154N-92W	0.292	0.245	28.42	10/2020	272.7	469.3	64.8	66.8	102.8	15.9	5,471.6	396.5	1,733.5	78.2	3,263.4	2,048.9	460.8	515.2	188.1	45.9
IVERSON 11-14-3H	PDP	BAKKEN	14-23 154N-92W	0.292	0.245	24.83	01/2021	199.4	306.9	42.4	48.8	67.2	10.4	3,885.3	268.3	1,323.9	72.3	2,220.8	1,468.3	360.2	337.1	160.8	30.2
IVERSON 11-14-HU	PDP	BAKKEN	14-15-22-23/N26-27 154N-92W	0.117	0.098	25.08	01/2021	220.9	580.2	80.1	21.6	50.8	7.8	1,886.3	132.3	677.8	28.9	1,047.3	715.0	371.4	641.5	150.6	61.3
IVERSON 21-14H	PDP	BAKKEN	14 154N 92W	0.292	0.245	22.33	01/2021	92.9	95.1	13.1	22.7	20.8	3.2	1,728.3	83.7	693.8	69.5	881.3	563.9	577.5	99.5	484.7	4.3
IVERSON 31-14TFH	PDP	THREE FORKS	14 154N 92W	0.000	0.011	17.42	01/2021	87.8	53.4	7.4	1.0	0.5	0.1	70.1	3.4	0.0	0.0	66.6	38.0	251.5	56.1	163.7	2.7
IVERSON 41-14-2HU	PDP	BAKKEN	10-11/14-15 154N-92W	0.126	0.105	19.33	01/2021	128.2	124.8	17.2	13.5	11.7	1.8	989.1	66.1	358.5	28.3	536.2	398.1	294.9	140.3	166.7	15.5
IVERSON 41-14H	PDP	BAKKEN	14 154N 92W	0.292	0.245	22.08	01/2021	89.5	148.4	20.5	21.9	32.5	5.0	1,768.4	84.1	749.7	68.1	866.5	555.7	328.0	155.0	238.5	6.5
IVERSON 41-14-HU	PDP	BAKKEN	14-23/13-24 154N-92W	0.146	0.122	33.50	01/2021	434.4	786.4	108.5	53.2	86.1	13.3	4,456.7	348.1	1,238.9	43.2	2,826.5	1,694.3	609.8	866.6	175.4	80.2
JOHN WILLIAM 14-12HU	PDP	BAKKEN	2-11/1-12 154N-92W	0.062	0.051	26.75	10/2020	257.2	368.1	50.8	13.0	16.7	2.6	1,031.9	75.4	308.7	16.0	631.7	414.8	524.0	409.7	266.8	41.6
KANNIANEN 11-4H	PDP	BAKKEN	4 153N 91W	0.010	0.008	25.58	01/2021	98.2	438.4	60.5	0.8	3.2	0.5	82.4	3.7	35.5	2.5	40.7	24.1	995.1	456.8	896.9	18.4
KANNIANEN 44-33H	PDP	BAKKEN	33 154N 91W	0.020	0.017	26.67	01/2021	129.6	226.5	31.3	2.2	3.5	0.5	185.7	10.2	67.6	5.2	102.6	59.4	852.0	235.6	722.4	9.1
KERNAN 12-10TFH	PDP	THREE FORKS	10 154N 92W	0.107	0.087	15.08	01/2021	65.4	73.5	10.1	5.7	5.7	0.9	420.6	20.3	227.7	21.6	150.9	115.5	206.3	77.7	140.9	4.2
KINNOIN 11-14H	PDP	BAKKEN	14 154N 91W	0.019	0.015	10.42	01/2021	28.4	94.4	13.0	0.4	1.3	0.2	38.3	1.7	19.5	3.6	13.4	12.7	829.1	108.9	800.7	14.5
KINNOIN 21-14H	PDP	BAKKEN	14 154N 91W	0.019	0.015	24.17	01/2021	100.9	427.6	59.0	1.6	5.9	0.9	156.0	8.0	70.5	4.7	72.8	46.8	754.1	451.4	653.2	23.8

Scenario: SPR_1021ESC
Input Settings: SET1021

ZEPHYR ENERGY LLC
PROVED RESERVES ADUIT
MOUNTRAIL COUNTY, ND
ONELINE SUMMARY
EFFECTIVE 10/2021

Well	Res Cat	Reservoir	Location	WI	NRI	Life (Years)	Start Date	Gross Oil (Mbbl)	Gross Gas (MMCF)	Gross NGL (Mbbl)	Net Oil (Mbbl)	Net Gas (MMCF)	Net NGL (Mbbl)	Net Revenue (M$)	Taxes (M$)	Operating Expense (M$)	Investment and P&A Cost (M$)	Undisc. NCF (M$)	Discounted NCF @ 10% (M$)	Ultimate Oil (Mbbl)	Ultimate Gas (MMCF)	Cum Oil (Mbbl)	Cum Gas (MMCF)
KINNOIN 41-14H	PDP	BAKKEN	14 154N 91W	0.019	0.015	25.00	01/2021	111.8	79.8	11.0	1.7	1.1	0.2	128.1	7.3	41.8	4.8	74.2	46.2	522.1	83.9	410.4	4.1
LACEY 11-10H	PDP	BAKKEN	10 152N 92W	0.128	0.106	15.00	01/2021	46.6	86.4	11.9	4.9	8.2	1.3	388.5	18.4	197.7	25.9	146.6	118.2	417.9	92.7	371.3	6.3
LACEY 12-10H	PDP	BAKKEN	10 152N 92W	0.128	0.106	25.17	01/2021	110.7	109.7	15.1	11.7	10.4	1.6	899.2	44.9	318.1	31.5	504.7	301.8	445.6	114.2	334.9	4.5
LACEY 12-10TFH	PDP	THREE FORKS	10 152N 92W	0.128	0.106	24.42	01/2021	96.8	92.1	12.7	10.2	8.7	1.3	780.5	37.9	286.8	31.5	424.3	259.6	290.6	95.8	193.8	3.7
LACEY 14-3-2TFX	PDP	THREE FORKS	3 152N 92W	0.129	0.108	16.75	01/2021	47.6	43.7	6.0	5.1	4.2	0.6	373.9	18.2	189.8	27.3	138.6	104.7	208.1	46.3	160.5	2.6
LACEY 14-3TFX	PDP	THREE FORKS	3 152N 92W	0.129	0.108	25.75	01/2021	110.0	128.0	17.7	11.8	12.3	1.9	926.0	45.7	342.1	32.6	505.6	301.0	355.1	134.4	245.1	6.3
LACEY 14-3XH	PDP	BAKKEN	3 152N 92W	0.129	0.108	25.50	01/2021	102.7	192.4	26.5	11.0	18.5	2.9	923.0	43.7	360.3	32.6	486.4	291.9	413.1	201.7	310.4	9.3
LAHTI 31-15TFX	PDP	THREE FORKS	15 154N 91W	0.010	0.008	17.00	01/2021	44.1	32.8	4.5	0.3	0.2	0.0	24.4	1.2	12.0	2.0	9.2	7.0	228.2	34.4	184.1	1.6
LAHTI 41-15TFX	PDP	THREE FORKS	15 154N 91W	0.010	0.008	17.67	01/2021	45.5	35.2	4.9	0.4	0.2	0.0	25.4	1.2	12.1	2.1	10.0	7.5	206.8	36.9	161.2	1.7
LEO 12-29H	PDP	BAKKEN	29 153N 91W	0.005	0.004	24.42	01/2021	91.2	246.3	34.0	0.4	0.9	0.1	32.1	1.5	13.3	1.2	16.1	10.2	591.2	258.6	500.1	12.3
LEO 13-29TFH	PDP	THREE FORKS	29 153N 91W	0.005	0.004	20.58	01/2021	93.7	89.3	12.3	0.4	0.3	0.0	27.7	1.3	11.9	1.1	13.3	8.9	285.6	93.7	191.9	4.4
LEO 14-29H	PDP	BAKKEN	29 153N 91W	0.005	0.004	19.92	01/2021	60.6	179.2	24.7	0.2	0.6	0.1	21.3	1.0	10.1	1.1	9.2	6.5	313.2	189.4	252.6	10.2
LITTLEFIELD 11-29H	PDP	BAKKEN	29 153N 91W	0.005	0.004	27.92	01/2021	120.9	164.9	22.8	0.5	0.6	0.1	38.5	2.0	11.8	1.2	23.5	13.1	602.6	171.4	481.8	6.5
LITTLEFIELD 11-30H	PDP	BAKKEN	30 153N 91W	0.005	0.004	22.92	01/2021	88.2	237.3	32.8	0.4	0.9	0.1	32.7	1.5	14.4	1.2	15.6	10.0	327.4	248.6	239.2	11.3
LITTLEFIELD 12-29TFH	PDP	THREE FORKS	29 153N 91W	0.005	0.004	20.33	01/2021	87.1	98.6	13.6	0.3	0.3	0.1	26.2	1.3	11.7	1.1	12.2	8.1	350.7	103.0	263.6	4.4
LITTLEFIELD 12-34H	PDP	BAKKEN	34 154N 91W	0.134	0.111	27.67	01/2021	118.7	903.6	124.7	13.1	89.4	13.8	1,680.2	76.6	725.0	35.2	843.4	456.9	853.8	968.9	735.1	65.3
LITTLEFIELD 14-13-2XH	PDP	BAKKEN	13 153N 91W	0.002	0.002	25.17	01/2021	98.7	703.5	97.1	0.2	1.0	0.2	19.4	0.8	8.4	0.5	9.7	5.7	414.0	739.0	315.4	35.5
LITTLEFIELD 14-13XH	PDP	BAKKEN	13 153N 91W	0.002	0.002	10.42	01/2021	22.9	129.1	17.8	0.0	0.2	0.0	3.8	0.2	2.2	0.4	1.1	1.0	273.7	142.5	250.7	13.4
LITTLEFIELD FEDERAL 11-34H	PDP	BAKKEN	34 154N 91W	0.134	0.111	28.00	01/2021	144.7	1,106.6	152.7	16.0	109.5	16.9	2,055.4	100.3	1,015.9	35.2	904.1	517.8	416.4	1,193.6	271.6	87.0
LOCKEN 11-22H	PDP	BAKKEN	22 153N 91W	0.006	0.005	16.50	10/2020	49.9	310.7	42.9	0.3	1.4	0.2	28.6	1.2	14.2	1.3	11.8	9.2	812.0	339.2	762.1	28.5
MAKI 41-33-2XH	PDP	BAKKEN	33 154N 91W	0.043	0.036	22.92	01/2021	85.6	325.1	44.9	3.1	10.5	1.6	297.5	13.9	130.6	10.3	142.6	95.9	455.0	345.8	369.4	20.7
MAKI 41-33XH	PDP	BAKKEN	33 154N 91W	0.043	0.036	15.33	01/2021	49.9	72.8	10.0	1.8	2.4	0.4	136.7	6.5	61.8	8.9	59.5	48.6	726.4	79.7	676.6	6.9
MAKI 42-33XH	PDP	BAKKEN	33 154N 91W	0.043	0.036	35.92	01/2021	284.2	269.5	37.2	10.3	8.7	1.3	816.8	58.9	206.4	13.3	538.3	270.5	552.9	279.9	268.7	10.4
MARMON 11-18TFH	PDP	THREE FORKS	18 153N 91W	0.004	0.003	18.17	01/2021	58.1	51.4	7.1	0.2	0.2	0.0	14.7	0.7	6.9	0.9	6.2	4.4	227.7	53.8	169.6	2.4
MARMON 12-18TFH	PDP	THREE FORKS	18 153N 91W	0.004	0.003	17.83	01/2021	49.6	50.5	7.0	0.2	0.2	0.0	12.7	0.6	5.9	0.9	5.3	3.9	211.6	53.1	162.0	2.6
MAYER 12-3H	PDP	BAKKEN	3 152N 92W	0.131	0.109	25.67	01/2021	105.6	182.0	25.1	11.6	17.8	2.7	952.8	45.2	363.3	33.1	511.1	305.2	460.7	189.3	355.0	7.3
MAYNARD URAN TRUST 11-24H	PDP	BAKKEN	24 153N 92W	0.084	0.069	21.00	01/2021	82.7	152.5	21.0	5.7	9.3	1.4	461.6	21.9	204.7	19.3	215.7	142.6	759.1	159.8	676.5	7.3
MCNAMARA 41-26-2XH	PDP	BAKKEN	22-23-26-27 153N 91W	0.003	0.003	23.33	01/2021	123.4	736.6	101.6	0.3	1.7	0.3	35.6	2.0	16.1	0.7	16.8	11.5	538.4	796.8	414.9	60.2
MCNAMARA 41-26H	PDP	BAKKEN	22-23 153N 91W	0.006	0.005	28.42	01/2021	242.4	518.1	71.5	1.3	2.4	0.4	107.4	7.4	35.5	1.6	62.9	37.5	683.2	550.4	440.8	32.2
MCNAMARA 41-26XH	PDP	BAKKEN	26 153N 91W	0.003	0.003	17.67	01/2021	65.5	378.3	52.2	0.2	0.9	0.1	18.4	0.8	10.0	0.7	6.9	5.1	382.4	402.7	316.8	24.3
MCNAMARA 42-26-3XH	PDP	BAKKEN	22-23-26-27 153N 91W	0.003	0.003	22.17	01/2021	146.1	1,013.2	139.8	0.4	2.3	0.4	44.4	2.7	20.3	0.7	20.7	14.7	579.7	1,108.1	433.6	94.9
MCNAMARA 42-26H	PDP	BAKKEN	26 153N 91W	0.003	0.003	18.75	01/2021	67.1	341.9	47.2	0.2	0.8	0.1	18.1	0.8	9.6	0.7	7.0	5.0	624.1	361.7	557.0	19.8
MCNAMARA 42-26H-2XH	PDP	BAKKEN	22-23-26-27 153N 91W	0.003	0.003	19.75	01/2021	97.3	615.3	84.9	0.3	1.4	0.2	28.3	1.6	13.4	0.7	12.7	9.3	438.4	672.0	341.0	56.7
MCNAMARA 42-26XH	PDP	BAKKEN	26 153N 91W	0.003	0.003	25.08	01/2021	123.9	642.5	88.7	0.3	1.5	0.2	34.6	1.9	15.9	0.8	16.0	9.9	465.3	676.3	341.4	33.8
MEIER 12-17-2H	PDP	BAKKEN	16-17 154N 92W	0.030	0.025	20.67	01/2021	134.7	398.4	55.0	3.3	8.8	1.4	295.0	18.1	130.5	7.0	139.4	98.6	302.7	435.2	168.0	36.8
MEIER 12-17-3H	PDP	BAKKEN	16-17 154N 92W	0.030	0.025	17.33	01/2021	92.8	256.1	35.3	2.3	5.7	0.9	197.0	11.1	95.8	6.6	83.5	63.2	189.3	279.6	96.5	23.5
MEIERS 11-17H	PDP	BAKKEN	17 154N 92W	0.030	0.025	21.83	01/2021	145.5	127.4	17.6	3.6	2.8	0.4	265.9	17.8	97.5	7.1	143.5	95.9	551.4	136.2	405.9	8.8
MEIERS 11-17XH	PDP	BAKKEN	8-9 / 16-17 154N-92W	0.020	0.016	21.83	01/2021	178.8	309.9	42.8	2.9	4.6	0.7	234.1	16.5	86.6	4.7	126.2	90.2	401.8	350.2	223.0	40.3
MEIERS 12-17H	PDP	BAKKEN	17 154N 92W	0.030	0.025	11.33	01/2021	44.8	75.7	10.4	1.1	1.7	0.3	84.0	4.0	47.9	5.8	26.3	23.2	363.3	82.3	318.5	6.6
MEIERS 44-18H	PDP	BAKKEN	18 154N 92W	0.030	0.025	19.83	01/2021	106.3	161.3	22.3	2.6	3.6	0.5	206.4	10.9	98.3	6.8	90.4	59.5	361.2	168.7	254.9	7.4
MEIERS 44-18TFH	PDP	THREE FORKS	18 154N 92W	0.030	0.025	22.33	01/2021	140.2	97.6	13.5	3.5	2.2	0.3	254.7	14.6	106.7	7.2	126.2	78.0	350.2	101.8	210.0	4.1
MOORE 11-7H	PDP	BAKKEN	7 154N 92W	0.219	0.177	20.50	01/2021	111.3	175.0	24.1	19.7	27.8	4.3	1,566.6	83.3	726.1	50.0	707.3	456.8	389.1	182.5	277.8	7.5
MOORE 14-7-2XH	PDP	BAKKEN	7 153N 91W	0.002	0.002	22.67	01/2021	83.3	294.3	40.6	0.1	0.5	0.1	13.6	0.6	6.2	0.5	6.2	4.1	279.1	309.1	195.8	14.8
MOORE 14-7XH	PDP	BAKKEN	7 153N 91W	0.002	0.002	13.17	01/2021	36.1	120.6	16.6	0.1	0.2	0.0	5.5	0.3	3.1	0.4	1.7	1.5	386.8	129.7	350.6	9.1
NESHEIM 11-24XH	PDP	BAKKEN	24 153N 91W	0.002	0.002	2.33	01/2021	6.0	16.4	2.3	0.0	0.0	0.0	0.8	0.0	0.6	0.3	-0.1	0.0	477.9	20.6	471.9	4.2
NIEMITALO 31-15XH	PDP	BAKKEN	15 154N 91W	0.010	0.008	33.17	01/2021	213.9	488.5	67.4	1.7	3.4	0.5	147.3	9.8	47.3	2.8	87.4	45.7	731.6	507.5	517.7	19.1
OGDEN - 11-3HU	PDP	BAKKEN	2-3/34-35 154-155N-92W	0.071	0.058	30.50	01/2021	352.2	785.7	108.4	20.4	40.6	6.3	1,748.5	131.3	533.5	19.8	1,063.9	666.0	571.2	861.9	218.9	76.2
OGDEN 11-3TFH	PDP	THREE FORKS	3 154N 92W	0.142	0.116	11.50	01/2021	43.8	49.9	6.9	5.1	5.2	0.8	365.8	17.6	216.9	27.2	104.0	90.9	335.2	53.5	291.4	3.6
OGDEN 12-3-2H	PDP	BAKKEN	3 154N 92W	0.142	0.116	21.00	01/2021	78.5	116.8	16.1	9.1	12.1	1.9	715.5	34.2	313.1	32.5	335.7	221.2	299.0	122.3	220.5	5.5
OGDEN 12-3-3H	PDP	BAKKEN	2-3 154N 92W	0.142	0.116	26.42	01/2021	238.4	311.8	43.0	27.5	32.2	5.0	2,158.2	154.7	671.7	36.6	1,295.2	833.4	417.0	340.3	178.6	28.5
OGDEN 12-3H	PDP	BAKKEN	3 154N 92W	0.142	0.116	24.58	01/2021	110.8	152.2	21.0	12.8	15.7	2.4	1,016.5	52.1	384.8	35.2	544.5	330.6	567.0	159.3	456.1	7.1
OGDEN 12-3XH	PDP	BAKKEN	2-3/10-11 154N 92W	0.124	0.101	24.58	01/2021	202.8	332.0	45.8	20.6	30.1	4.6	1,649.3	114.3	556.3	30.8	947.9	630.6	367.6	365.4	164.8	33.4
OGDEN 13-3TFX	PDP	THREE FORKS	3 154N 92W	0.124	0.101	7.50	01/2021	24.4	28.5	3.9	2.5	2.6	0.4	175.6	8.5	125.9	22.0	19.3	22.3	216.5	31.0	192.1	2.5
OGDEN 14-3TFX	PDP	THREE FORKS	3 154N 92W	0.124	0.101	23.83	01/2021	93.2	255.8	35.3	9.5	23.2	3.6	840.3	39.0	358.1	30.2	413.0	260.0	266.5	272.9	173.2	17.1
OGDEN 14-3XH	PDP	BAKKEN	2-3/10-11 154N 92W	0.124	0.101	22.92	01/2021	167.7	333.9	46.1	17.0	30.3	4.7	1,399.6	92.8	549.6	29.6	727.6	491.3	320.4	368.1	152.7	34.2
OGDEN 41-9HU	PDP	BAKKEN	4-5-6/7-8-9 154N-92W	0.040	0.032	20.00	10/2020	129.8	192.4	26.5	4.2	5.5	0.9	322.8	20.8	128.0	8.8	165.2	118.0	407.7	212.6	277.9	20.2
OGDEN 41-9TFHU	PDP	THREE FORKS	4-5-6/7-8-9 154N-92W	0.040	0.032	29.67	01/2021	290.1	803.6	110.9	9.3	23.0	3.6	844.1	59.4	312.3	10.8	461.6	274.9	522.8	864.4	232.7	60.8
OJA 14-27XH	PDP	BAKKEN	27 154N 91W	0.067	0.055	21.33	01/2021	88.8	355.3	49.0	4.9	17.6	2.7	476.5	25.0	219.3	15.6	216.6	150.2	539.4	381.5	450.6	26.3
OLSON FEDERAL 42-8H	PDP	BAKKEN	8 153N 91W	0.001	0.001	19.00	01/2021	50.7	192.9	26.6	0.1	0.2	0.0	5.7	0.3	2.9	0.3	2.2	1.6	683.7	201.6	633.0	8.8
PAM LOCKEN 21-22TFH	PDP	THREE FORKS	22 153N 91W	0.006	0.005	13.33	01/2021	33.2	25.5	3.5	0.2	0.1	0.0	12.1	0.6	6.7	1.2	3.6	3.1	207.5	27.0	174.3	1.5
PATTEN 44-3H	PDP	BAKKEN	3 153N 91W	0.010	0.008	15.33	01/2021	42.6	341.7	47.2	0.3	2.5	0.4	42.6	1.8	22.9	2.0	15.9	12.5	783.0	371.4	740.4	29.6
PEERY STATE 11-25-2H	PDP	BAKKEN	25 153N 92W	0.005	0.004	10.92	01/2021	24.8	14.4	2.0	0.1	0.1	0.0	7.1	0.3	3.7	1.0	2.1	2.0	223.0	15.6	198.2	1.2
PEERY STATE 21-25H	PDP	BAKKEN	25 153N 92W	0.005	0.004	16.67	01/2021	57.2	162.6	22.4	0.2	0.6	0.1	20.7	1.0	10.0	1.1	8.7	6.7	323.0	176.0	265.8	13.4
PEERY STATE 22-25H	PDP	BAKKEN	25 153N 92W	0.005	0.004	19.25	01/2021	53.2	144.9	20.0	0.2	0.5	0.1	19.4	0.9	9.4	1.1	8.0	5.6	241.3	152.8	188.1	7.9
PENNINGTON 11-3H	PDP	BAKKEN	3 152N 92W	0.131	0.109	23.08	01/2021	76.9	140.5	19.4	8.4	13.7	2.1	691.8	32.8	274.8	31.2	353.0	219.7	420.7	146.4	343.9	5.8
PENNINGTON 11-3TFH	PDP	THREE FORKS	3 152N 92W	0.131	0.109	23.42	01/2021	87.8	143.8	19.8	9.6	14.1	2.2	775.4	36.9	311.1	31.8	395.6	249.3	329.9	152.0	242.1	8.2
PENNINGTON 21-3H	PDP	BAKKEN	3 152N 92W	0.131	0.109	19.75	01/2021	55.0	88.7	12.2	6.0	8.7	1.3	477.1	22.7	217.3	29.4	207.6	143.1	290.3	92.8	235.3	4.0
PLATT 43-28H	PDP	BAKKEN	28 154N 91W	0.066	0.055	23.42	01/2021	113.6	364.3	50.3	6.2	17.9	2.8	578.9	29.7	260.0	16.0	273.1	169.2	562.9	380.9	449.3	16.6
PLATT 44-28H	PDP	BAKKEN	28 154N 91W	0.066	0.055	10.67	01/2021	36.4	103.6	14.3	2.0	5.1	0.8	167.9	7.8	101.2	12.4	46.5	41.4	619.5	111.2	583.1	7.7
RICHARDSON FEDERAL 11-9H	PDP	BAKKEN	9 153N 91W	0.001	0.001	16.83	01/2021	45.8	317.7	43.8	0.1	0.3	0.1	6.3	0.3	3.3	0.3	2.4	1.8	1,039.8	338.9	994.0	21.2
ROBERT PATTEN 44-3TFH	PDP	THREE FORKS	3 153N 91W	0.010	0.008	9.67	01/2021	29.1	34.3	4.7	0.2	0.2	0.0	17.0	0.8	8.8	1.8	5.6	5.3	230.4	38.1	201.3	3.7
RODNEY OLSON FEDERAL 42-8-2TFH	PDP	THREE FORKS	8 153N 91W	0.001	0.001	25.08	01/2021	128.1	149.9	20.7	0.2	0.2	0.0	11.8	0.7	4.5	0.4	6.3	3.8	372.3	156.8	244.3	6.9
SATTERTHWAITE 14-35HU	PDP	BAKKEN	6/1-2/31/35-36 153/4N-92/93W	0.031	0.025	28.58	09/2021	281.9	338.2	46.7	7.1	7.6	1.2	557.5	41.3	175.1	17.7	323.3	194.5	473.0	567.6	191.2	229.4

Scenario: SPR_1021ESC
Input Settings: SET1021

ZEPHYR ENERGY LLC
PROVED RESERVES ADUIT
MOUNTRAIL COUNTY, ND
ONELINE SUMMARY
EFFECTIVE 10/2021

Well	Res Cat	Reservoir	Location	WI	NRI	Life (Years)	Start Date	Gross Oil (Mbbl)	Gross Gas (MMCF)	Gross NGL (Mbbl)	Net Oil (Mbbl)	Net Gas (MMCF)	Net NGL (Mbbl)	Net Revenue (M$)	Taxes (M$)	Operating Expense (M$)	Investment and P&A Cost (M$)	Undisc. NCF (M$)	Discounted NCF @ 10% (M$)	Ultimate Oil (Mbbl)	Ultimate Gas (MMCF)	Cum Oil (Mbbl)	Cum Gas (MMCF)
SATTERTHWAITE 14-35TFHU	PDP	THREE FORKS	6/1-2/31/35-36 153/4N-92/93W	0.031	0.025	26.17	10/2021	226.1	312.2	43.1	5.7	7.1	1.1	451.3	31.8	160.0	17.2	242.3	149.7	376.1	508.1	150.1	195.9
SATTERTHWAITE 14-6H	PDP	BAKKEN	6 153N 92W	0.188	0.152	3.33	01/2021	4.6	10.1	1.4	0.7	1.4	0.2	54.5	2.5	41.2	30.6	-19.8	-12.6	65.3	13.2	60.8	3.0
SATTERTHWAITE 14-7HU	PDP	BAKKEN	1-12 / 6-7 153N-92-93W	0.047	0.038	24.83	10/2021	201.4	231.3	31.9	7.6	7.8	1.2	586.1	40.8	210.4	25.6	309.3	195.1	345.1	390.0	143.8	158.6
S-BAR 11-7HU	PDP	BAKKEN	6-7 / 5-8 153N-92W	0.047	0.038	29.83	10/2021	433.4	703.0	97.0	16.4	23.8	3.7	1,320.0	105.2	354.3	26.8	833.7	579.5	433.4	703.0	0.0	0.0
S-BAR 11-7TFHU	PDP	THREE FORKS	6-7 / 5-8 153N-92W	0.047	0.038	23.75	10/2021	231.3	380.4	52.5	8.8	12.9	2.0	695.3	51.3	236.7	25.4	381.9	273.4	231.3	380.4	0.0	0.0
SCOTT MEIERS 12-17TFH	PDP	THREE FORKS	17 154N 92W	0.030	0.025	21.67	01/2021	106.0	88.0	12.1	2.6	1.9	0.3	194.4	9.8	85.2	7.1	92.3	59.0	328.8	92.0	222.8	4.0
SMITH 11-20H	PDP	BAKKEN	20 153N 91W	0.005	0.004	18.83	01/2021	97.0	234.8	32.4	0.4	0.9	0.1	35.0	2.1	15.1	1.1	16.7	12.2	705.8	253.7	608.8	18.8
SMITH 41-24H	PDP	BAKKEN	24 153N 92W	0.084	0.069	20.25	01/2021	58.2	366.8	50.6	4.0	22.5	3.5	454.8	19.8	231.9	18.9	184.1	120.3	333.4	384.1	275.1	17.3
SNYDER 21-11H	PDP	BAKKEN	11 153N 91W	0.004	0.003	31.58	10/2020	169.3	458.4	63.3	0.5	1.3	0.2	49.9	3.0	16.2	1.1	29.6	15.6	646.6	476.1	477.3	17.7
URAN 12-24TFH	PDP	THREE FORKS	24 153N 92W	0.084	0.069	20.58	01/2021	69.5	40.9	5.6	4.8	2.5	0.4	343.4	16.8	145.5	19.3	161.8	109.2	292.8	43.0	223.2	2.1
URAN 21-24TFH	PDP	THREE FORKS	24 153N 92W	0.084	0.069	23.50	01/2021	115.3	142.2	19.6	7.9	8.7	1.3	615.9	29.6	249.4	20.5	316.4	195.4	323.2	148.2	207.9	6.0
VANGEN 11-3TFH	PDP	THREE FORKS	3 152N 92W	0.131	0.109	23.17	01/2021	85.7	92.3	12.7	9.4	9.0	1.4	719.0	34.7	281.5	31.2	371.5	233.5	341.7	96.9	256.0	4.6
WALDOCK 14-4-2XH	PDP	BAKKEN	4 153N 91W	0.006	0.005	29.83	01/2021	145.0	782.4	108.0	0.7	3.3	0.5	75.6	3.7	30.9	1.5	39.5	21.3	494.0	812.3	349.1	29.9
WALDOCK 14-4XH	PDP	BAKKEN	4 153N 91W	0.006	0.005	2.25	01/2021	3.5	21.7	3.0	0.0	0.1	0.0	1.8	0.1	1.3	0.9	-0.5	-0.4	311.5	27.5	307.9	5.8
WALDOCK FEDERAL 14-4-3XH	PDP	BAKKEN	4 153N 91W	0.006	0.005	26.42	01/2021	105.7	974.8	134.5	0.5	4.1	0.6	68.5	2.9	34.1	1.4	30.1	17.4	543.5	1,016.1	437.9	41.3
WARDEN 43-9TFH	PDP	THREE FORKS	9 154N 92W	0.010	0.008	6.42	01/2021	20.5	20.4	2.8	0.2	0.2	0.0	11.8	0.6	6.5	1.8	2.9	3.1	216.3	23.3	195.9	2.9
WHITE 43-33H	PDP	BAKKEN	32-33 154N-91W	0.020	0.017	33.33	01/2021	415.6	1,017.0	140.4	7.2	15.7	2.4	633.7	48.3	182.5	6.0	396.9	240.0	696.5	1,105.7	280.9	88.6
WHITE 43-33TFH	PDP	THREE FORKS	33 154N 91W	0.020	0.017	20.75	01/2021	113.4	59.7	8.2	2.0	0.9	0.1	140.5	7.8	60.7	4.6	67.3	43.1	310.4	62.3	196.9	2.6
WHITE 44-33-2TFH	PDP	THREE FORKS	28-29/32-33 154N-91W	0.043	0.036	20.42	01/2021	160.3	263.0	36.3	5.8	8.5	1.3	454.9	32.0	171.9	22.8	228.2	169.2	196.5	322.1	36.1	59.2
APO WELL ABANDONMENT	PDP			0.000	0.000	23.00	10/2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	331.8	-331.8	-37.3	0.0	0.0	0.0	0.0
ALLISON 14-6H	PDP-APO	BAKKEN	6 153N 92W	0.000	0.000	11.00	01/2021	38.3	56.5	7.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	153.2	63.8	114.9	7.3
BARB W. 11-6TFH	PDP-APO	THREE FORKS	6 153N 92W	0.000	0.000	14.17	01/2021	56.3	44.6	6.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	177.4	47.5	121.1	3.0
DOUG KINNOIN 11-14H	PDP-APO	BAKKEN	14 154N 91W	0.000	0.000	17.42	01/2021	96.2	319.4	44.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	606.5	343.1	510.3	23.6
EARL T 11-6TFH	PDP-APO	THREE FORKS	6 153N 92W	0.000	0.000	17.67	01/2021	84.8	90.4	12.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	199.7	95.3	114.9	4.9
HANSEN 21-20TFH	PDP-APO	THREE FORKS	20 153N 91W	0.000	0.000	21.83	01/2021	127.1	125.7	17.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	429.5	131.7	302.4	6.0
IVERSON 44-11-2H	PDP-APO	BAKKEN	11 154N 92W	0.000	0.000	7.17	01/2021	22.6	18.3	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	173.8	20.2	151.2	1.9
IVERSON 44-11H	PDP-APO	BAKKEN	11 154N 92W	0.000	0.000	8.00	01/2021	24.6	73.6	10.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	233.6	86.9	209.1	13.3
JB 11-6TFH	PDP-APO	THREE FORKS	6 153N 92W	0.000	0.000	10.50	01/2021	36.0	18.0	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	140.7	19.6	104.7	1.5
KANNIANEN 21-4H	PDP-APO	BAKKEN	4 153N 91W	0.000	0.000	17.00	01/2021	77.5	656.6	90.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	357.5	714.2	280.0	57.5
OJA 13-27-2XH	PDP-APO	BAKKEN	27 154N 91W	0.000	0.000	6.25	01/2021	14.7	189.6	26.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	274.5	211.8	259.8	22.3
OJA 13-27-3XH	PDP-APO	BAKKEN	27 154N 91W	0.000	0.000	21.00	01/2021	113.8	596.8	82.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	569.3	633.7	455.5	36.9
PEERY STATE 12-25TFH	PDP-APO	THREE FORKS	25 153N 92W	0.000	0.000	19.42	01/2021	97.5	138.9	19.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	331.1	145.4	233.5	6.4
PEERY STATE 21-25TFH	PDP-APO	THREE FORKS	25 153N 92W	0.000	0.000	19.67	01/2021	100.3	103.1	14.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	295.2	107.8	194.9	4.7
URAN 11-24-2H	PDP-APO	BAKKEN	24 153N 92W	0.000	0.000	10.17	01/2021	33.9	51.5	7.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	264.6	55.4	230.8	3.9
URAN FEDERAL 21-24H	PDP-APO	BAKKEN	24 153N 92W	0.000	0.000	12.17	01/2021	45.4	82.3	11.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	304.0	88.3	258.5	6.0
URAN FEDERAL 22-24H	PDP-APO	BAKKEN	24 153N 92W	0.000	0.000	19.17	01/2021	90.9	690.0	95.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	359.9	735.8	269.1	45.8
SUBTOTAL PROVED DEVELOPED PRODUCING								**20,192.0**	**46,728.9**	**6,448.6**	**1,097.6**	**1,823.1**	**281.4**	**90,402.9**	**5,522.9**	**34,297.1**	**2,902.2**	**47,680.8**	**30,458.7**	**75,586.2**	**50,432.1**	**55,394.2**	**3,703.3**
PROVED NON-PRODUCING																							
FLADELAND 12-10HU	PNP	BAKKEN	3-4/(N/2) 9-10 154N-92W	0.067	0.054	21.75	11/2021	173.9	411.2	56.7	9.5	20.0	3.1	796.3	54.8	290.6	22.3	428.7	312.9	304.7	411.2	130.8	0.0
IVERSON 11-14H	PNP	BAKKEN	14 154N 92W	0.292	0.245	21.00	11/2021	107.2	194.3	26.8	26.3	42.6	6.6	2,132.6	113.4	942.3	96.0	981.0	619.8	464.0	194.3	356.8	0.0
KANNIANEN 43-33H	PNP	BAKKEN	33 154N 91W	0.020	0.017	16.58	11/2021	45.1	97.7	13.5	0.8	1.5	0.2	63.4	3.0	28.0	6.3	26.0	19.5	435.9	97.7	390.8	0.0
LACEY 13-10H	PNP	BAKKEN	10 152N 92W	0.128	0.106	22.67	11/2021	103.3	65.4	9.0	10.9	6.2	1.0	800.2	39.9	306.1	43.1	411.3	250.9	293.3	65.4	189.9	0.0
PEERY STATE 11-25H	PNP	BAKKEN	25 153N 92W	0.005	0.004	22.92	11/2021	91.5	216.5	29.9	0.4	0.8	0.1	33.0	1.6	14.2	1.7	15.5	9.6	523.0	216.5	431.5	0.0
SUBTOTAL PROVED NON-PRODUCING								**521.0**	**985.0**	**135.9**	**47.8**	**71.1**	**11.0**	**3,825.6**	**212.6**	**1,581.1**	**169.4**	**1,862.5**	**1,212.7**	**2,020.9**	**985.0**	**1,499.9**	**0.0**
PROVED UNDEVELOPED																							
BIGFOOT	PUD-DUC	BAKKEN		0.015	0.012	17.58	11/2021	549.0	459.5	63.4	6.5	4.9	0.8	459.7	42.0	72.1	119.4	226.1	179.8	549.0	459.5	0.0	0.0
LACEY 12-1-3H MB (Infill #1)	PUD-DUC	BAKKEN	2-3 152N 92W	0.131	0.109	26.92	01/2022	440.1	567.7	78.3	48.1	55.5	8.6	3,639.2	301.1	842.7	757.8	1,737.6	1,149.9	440.1	567.7	0.0	0.0
LACEY 13-10-2H (Infill #2)	PUD-DUC	BAKKEN	10-11 152N-92W	0.128	0.106	26.92	01/2022	440.1	567.7	78.3	46.6	53.7	8.3	3,519.8	291.2	818.8	817.4	1,592.3	1,027.5	440.1	567.7	0.0	0.0
LACEY 13-10HU MB #1	PUD-DUC	BAKKEN	10-11 / 14-15 152N-92W	0.065	0.054	26.83	01/2022	439.9	567.4	78.3	23.6	27.3	4.2	1,786.9	147.9	415.8	422.2	801.0	515.5	439.9	567.4	0.0	0.0
LACEY 14-3-2XH (Infill #1)	PUD-DUC	BAKKEN	2-3 / 10-11 152N 92W	0.129	0.108	26.92	01/2022	440.1	567.7	78.3	47.3	54.6	8.4	3,579.5	296.2	830.8	764.3	1,688.3	1,111.7	440.1	567.7	0.0	0.0
LACEY 14-3-3XH (Infill #2)	PUD-DUC	BAKKEN	2-3 / 10-11 152N 92W	0.129	0.108	26.92	01/2022	440.1	567.7	78.3	47.3	54.6	8.4	3,579.5	296.2	830.8	764.3	1,688.3	1,111.7	440.1	567.7	0.0	0.0
LACEY 43-2HMB (Infill #2)	PUD-DUC	BAKKEN	2-3 152N 92W	0.131	0.109	26.92	01/2022	440.1	567.7	78.3	48.1	55.5	8.6	3,639.2	301.1	842.7	759.0	1,736.4	1,148.9	440.1	567.7	0.0	0.0
LEHR	PUD-DUC	BAKKEN		0.013	0.011	26.42	01/2022	439.2	565.8	78.1	4.7	5.4	0.8	352.3	29.2	86.8	85.6	150.7	96.2	439.2	565.8	0.0	0.0
LITTLEFIELD 41-2HU MB #1	PUD-DUC	BAKKEN	2-11 / 1-12 152N-92W	0.065	0.054	26.92	01/2022	440.1	567.7	78.3	23.7	27.3	4.2	1,791.4	148.2	415.8	400.6	826.8	537.6	440.1	567.7	0.0	0.0
MAKI 11-27-2HU	PUD-DUC	BAKKEN	27-28/33-34 154N-91W	0.055	0.046	27.17	04/2022	440.1	567.7	78.3	20.1	23.2	3.6	1,520.8	125.7	366.3	328.3	700.4	446.3	440.1	567.7	0.0	0.0
MAKI 11-27HU	PUD-DUC	BAKKEN	22-23/26-27 154N-91W	0.005	0.004	26.42	01/2022	439.2	565.8	78.1	1.7	2.0	0.3	128.0	10.6	31.5	29.2	56.6	36.8	439.2	565.8	0.0	0.0
NIEMITALO 31-15-2XH	PUD-DUC	BAKKEN	15-22/14-23 154N-91W	0.010	0.008	26.42	01/2022	439.2	565.8	78.1	3.4	3.9	0.6	256.0	21.2	63.1	60.2	111.5	71.9	439.2	565.8	0.0	0.0
NIEMITALO 31-15-3XH	PUD-DUC	BAKKEN	15-22/14-23 154N-91W	0.010	0.008	26.42	01/2022	439.2	565.8	78.1	3.4	3.9	0.6	256.0	21.2	63.1	61.5	110.2	70.8	439.2	565.8	0.0	0.0
SUBTOTAL PUD-DUC								**5,826.3**	**7,264.3**	**1,002.5**	**324.6**	**371.7**	**57.4**	**24,508.3**	**2,031.9**	**5,680.1**	**5,369.8**	**11,426.5**	**7,504.5**	**5,826.3**	**7,264.3**	**0.0**	**0.0**
ABBOTT - TFK INFILL #1 (E-W)	PUD	THREE FORKS	7-8/17-18 153N-91W	0.002	0.002	11.42	01/2022	216.4	230.5	31.8	0.4	0.4	0.1	26.5	2.3	5.9	12.7	5.6	3.8	216.4	230.5	0.0	0.0
ABBOTT - MB INFILL #1 (E-W)	PUD	BAKKEN	7-8/17-18 153N-91W	0.002	0.002	23.08	01/2022	313.9	400.6	55.3	0.5	0.6	0.1	40.5	3.3	10.7	12.8	13.8	8.3	313.9	400.6	0.0	0.0
ABBOTT 11-18MB (Infill #1)	PUD	BAKKEN	17-18 153N 91W	0.004	0.003	27.83	11/2022	440.3	568.0	78.4	1.5	1.8	0.3	114.0	9.4	27.8	25.6	51.2	30.2	440.3	568.0	0.0	0.0
ABBOTT 11-18MB (Infill #2)	PUD	BAKKEN	17-18 153N 91W	0.004	0.003	27.83	11/2022	440.3	568.0	78.4	1.5	1.8	0.3	114.0	9.4	27.8	25.6	51.2	30.2	440.3	568.0	0.0	0.0
ABBOTT W. MB #1 (N-S)	PUD	BAKKEN	12-13 / 7-18 153N-91-92W	0.001	0.001	23.58	07/2022	313.9	400.6	55.3	0.4	0.4	0.1	26.8	2.2	7.2	7.5	10.0	6.1	313.9	400.6	0.0	0.0
ABBOTT W. TFK #1 (N-S)	PUD	THREE FORKS	12-13 / 7-18 153N-91-92W	0.001	0.001	11.92	07/2022	216.4	230.5	31.8	0.2	0.2	0.0	17.5	1.5	4.0	7.4	4.6	3.2	216.4	230.5	0.0	0.0
BANSHEE WEST MB #1	PUD	BAKKEN	2-11-14/3-10-15 153N-91W	0.003	0.003	27.67	10/2022	440.1	567.7	78.3	1.2	1.3	0.2	86.7	7.2	21.1	19.5	38.9	23.2	440.1	567.7	0.0	0.0
BRAAFLAT 11-12 (W) MB #1	PUD	BAKKEN	W1-2 / 11-W12 153N-91W	0.001	0.001	23.67	08/2022	313.9	400.6	55.3	0.3	0.3	0.0	18.8	1.5	5.0	5.3	7.0	4.2	313.9	400.6	0.0	0.0
BRAAFLAT 11-14MB (Infill #1)	PUD	BAKKEN	11-14 153N 91W	0.004	0.003	27.67	10/2022	440.1	567.7	78.3	1.4	1.6	0.3	106.1	8.8	25.8	23.9	47.6	28.4	440.1	567.7	0.0	0.0
DEAL - WHITE MB #1	PUD	BAKKEN	28-29/32-33 154N-91W	0.043	0.036	27.00	01/2022	440.3	568.0	78.4	15.9	18.4	2.8	1,203.3	99.5	286.6	267.1	550.1	357.0	440.3	568.0	0.0	0.0

Scenario: SPR_1021ESC
Input Settings: SET1021

ZEPHYR ENERGY LLC
PROVED RESERVES ADUIT
MOUNTRAIL COUNTY, ND
ONELINE SUMMARY
EFFECTIVE 10/2021

Well	Res Cat	Reservoir	Location	WI	NRI	Life (Years)	Start Date	Gross Oil (Mbbl)	Gross Gas (MMCF)	Gross NGL (Mbbl)	Net Oil (Mbbl)	Net Gas (MMCF)	Net NGL (Mbbl)	Net Revenue (M$)	Taxes (M$)	Operating Expense (M$)	Investment and P&A Cost (M$)	Undisc. NCF (M$)	Discounted NCF @ 10% (M$)	Ultimate Oil (Mbbl)	Ultimate Gas (MMCF)	Cum Oil (Mbbl)	Cum Gas (MMCF)
HANSEN 14-20XMB ((Infill #1)	PUD	BAKKEN	20-21/28-29 153N 91W	0.005	0.004	27.83	12/2022	440.1	567.7	78.3	1.8	2.1	0.3	136.1	11.2	33.3	30.7	60.9	35.5	440.1	567.7	0.0	0.0
HANSEN 21-20MB ((Infill #1)	PUD	BAKKEN	20-21 153N 91W	0.005	0.004	27.83	11/2022	440.3	568.0	78.4	1.9	2.2	0.3	142.1	11.7	34.6	31.9	63.8	37.6	440.3	568.0	0.0	0.0
KANNIANEN MB #1	PUD	BAKKEN	4-5/32-33 153-154N-91W	0.010	0.009	27.25	01/2022	440.7	569.0	78.5	3.8	4.4	0.7	288.1	23.8	65.9	58.9	139.5	92.5	440.7	569.0	0.0	0.0
KANNIANEN TFK #1	PUD	THREE FORKS	4-5/32-33 153-154N-91W	0.010	0.009	11.50	12/2021	216.7	231.1	31.9	1.9	1.8	0.3	133.9	11.7	29.3	60.0	32.9	23.8	216.7	231.1	0.0	0.0
KINNOIN - E. MB #1	PUD	BAKKEN	13-24/14-23 154N-91W	0.010	0.008	27.42	01/2023	439.2	565.8	78.1	3.4	3.9	0.6	253.0	20.9	63.9	59.7	108.4	62.2	439.2	565.8	0.0	0.0
LACEY 12-10-2H MB (Infill #1)	PUD	BAKKEN	10-11 152N 92W	0.128	0.106	28.92	01/2024	440.1	567.7	78.3	46.6	53.7	8.3	3,486.8	286.6	869.3	791.1	1,539.8	796.3	440.1	567.7	0.0	0.0
LACEY 13-10TFHU TFK #1	PUD	THREE FORKS	10-11 / 14-15 152N-92W	0.065	0.054	13.42	01/2024	216.4	230.5	31.8	11.6	11.1	1.7	796.9	69.4	189.1	398.1	140.3	69.3	216.4	230.5	0.0	0.0
LEO 12-29MB (Infill #1)	PUD	BAKKEN	28-29 153N 91W	0.005	0.004	27.83	12/2022	440.1	567.7	78.3	1.7	2.0	0.3	130.4	10.8	31.9	29.5	58.2	34.0	440.1	567.7	0.0	0.0
LIITLEFIELD FED 13-34HU	PUD	BAKKEN	2-3/34-35 153-154N-91W	0.070	0.057	26.75	12/2021	439.9	567.4	78.3	25.2	29.1	4.5	1,918.6	158.9	458.9	430.1	870.7	572.3	439.9	567.4	0.0	0.0
LITTLEFIELD - N XU. MB #1	PUD	BAKKEN	20-21/28-29 153N-91W	0.005	0.004	26.92	01/2022	440.1	567.7	78.3	1.8	2.1	0.3	137.3	11.4	32.9	30.7	62.4	40.5	440.1	567.7	0.0	0.0
LITTLEFIELD - N XU. TFK #1	PUD	THREE FORKS	20-21/28-29 153N-91W	0.005	0.004	26.33	03/2022	344.5	460.1	63.5	1.4	1.7	0.3	108.6	8.6	30.0	30.7	39.4	21.6	344.5	460.1	0.0	0.0
LITTLEFIELD - S XU. MB #1	PUD	BAKKEN	28-29 / 32-33 153N-91W	0.002	0.002	27.92	01/2023	440.1	567.7	78.3	0.9	1.0	0.2	65.0	5.4	16.0	14.7	28.9	16.7	440.1	567.7	0.0	0.0
LITTLEFIELD - S XU. TFK #1	PUD	THREE FORKS	28-29 / 32-33 153N-91W	0.002	0.002	27.08	01/2023	344.3	459.8	63.5	0.7	0.8	0.1	51.6	4.1	14.5	14.7	18.2	8.9	344.3	459.8	0.0	0.0
LITTLEFIELD 41-2TFHU TFK #1	PUD	THREE FORKS	2-11 / 1-12 152N-92W	0.065	0.054	27.08	01/2023	344.3	459.8	63.5	18.5	22.1	3.4	1,404.0	110.9	394.9	400.6	497.6	243.5	344.3	459.8	0.0	0.0
LITTLEFIELD FED 13-34MB	PUD	BAKKEN	34-35 154N 91W	0.134	0.111	27.83	01/2023	439.9	567.4	78.3	48.7	56.1	8.7	3,639.1	300.0	898.9	830.6	1,609.6	926.9	439.9	567.4	0.0	0.0
LOCKEN - N XU. MB #1	PUD	BAKKEN	15-16 / 21-22 153N - 91W	0.003	0.002	27.58	06/2022	440.6	568.7	78.5	1.0	1.1	0.2	72.7	6.0	17.4	16.0	33.3	20.7	440.6	568.7	0.0	0.0
LOCKEN 11-22 MB #1	PUD	BAKKEN	21-28 / 22-27 153N-91W	0.004	0.003	27.67	09/2022	440.3	568.0	78.4	1.5	1.7	0.3	111.3	9.2	26.8	24.8	50.5	30.4	440.3	568.0	0.0	0.0
MUREX PAD MB #1	PUD	BAKKEN	26-35/25-36 154N-91W	0.034	0.028	26.83	01/2022	439.9	567.4	78.3	12.2	14.0	2.2	920.3	76.2	221.7	207.5	415.0	269.0	439.9	567.4	0.0	0.0
NESHEIM 1-24 MB #1	PUD	BAKKEN	14-23 / W13-W24 153N-91W	0.003	0.003	24.00	10/2022	314.2	401.2	55.4	0.9	1.0	0.2	65.3	5.3	17.4	18.1	24.5	14.4	314.2	401.2	0.0	0.0
PEERY S - XU. MB #1	PUD	BAKKEN	30-31 / 25-36 153N-91-92W	0.003	0.002	28.92	01/2024	440.1	567.7	78.3	0.9	1.1	0.2	69.0	5.7	17.2	15.7	30.5	15.8	440.1	567.7	0.0	0.0
PEERY S - XU. TFK #1	PUD	THREE FORKS	30-31 / 25-36 153N-91-92W	0.003	0.002	28.08	01/2024	344.3	459.8	63.5	0.7	0.9	0.1	54.8	4.3	15.6	15.7	19.2	8.4	344.3	459.8	0.0	0.0
PEERY STATE 25 MB #1	PUD	BAKKEN	19-30 / 20-29 153N-91W	0.025	0.020	27.67	01/2023	439.6	566.8	78.2	8.9	10.2	1.6	663.4	54.7	165.6	153.7	289.3	166.3	439.6	566.8	0.0	0.0
PEERY STATE 25 TFK #1	PUD	THREE FORKS	19-30 / 20-29 153N-91W	0.025	0.020	26.83	01/2023	343.9	458.8	63.3	6.9	8.3	1.3	525.7	41.6	150.3	153.6	180.2	87.2	343.9	458.8	0.0	0.0
PENNINGTON - N. MB #1	PUD	BAKKEN	2-3 / 36-31-32 152/53N - 91-92W	0.069	0.057	28.00	01/2023	440.3	568.0	78.4	25.2	29.1	4.5	1,884.8	155.3	462.6	425.5	841.4	485.1	440.3	568.0	0.0	0.0
PENNINGTON - N. TFK #1	PUD	THREE FORKS	2-3 / 36-31-32 152/53N - 91-92W	0.069	0.057	27.17	01/2023	344.5	460.1	63.5	19.7	23.6	3.6	1,494.5	118.0	420.1	425.2	531.2	260.3	344.5	460.1	0.0	0.0
PENNINGTON 11-3HU MB #1	PUD	BAKKEN	3-10 / 4-9 152-92W	0.065	0.054	27.92	01/2023	440.1	567.7	78.3	23.7	27.3	4.2	1,769.4	145.8	434.5	400.6	788.4	454.5	440.1	567.7	0.0	0.0
PENNINGTON 11-3TFHU TFK #1	PUD	THREE FORKS	3-10 / 4-9 152N-92W	0.065	0.054	27.08	01/2023	344.3	459.8	63.5	18.5	22.1	3.4	1,402.7	110.8	394.5	400.2	497.2	243.3	344.3	459.8	0.0	0.0
PETERSON MB #1	PUD	BAKKEN	23-24/25-26 153N-92W	0.001	0.001	23.92	01/2023	313.6	400.0	55.2	0.2	0.2	0.0	16.2	1.3	4.4	4.6	5.9	3.3	313.6	400.0	0.0	0.0
PETERSON TFK #1	PUD	THREE FORKS	23-24/25-26 153N-92W	0.001	0.001	12.33	01/2023	216.2	230.2	31.8	0.2	0.1	0.0	10.4	0.9	2.4	4.6	2.5	1.6	216.2	230.2	0.0	0.0
PLATT	PUD	THREE FORKS		0.066	0.055	11.42	01/2022	216.4	230.5	31.8	11.9	11.3	1.8	845.4	74.0	175.4	390.5	205.4	145.1	216.4	230.5	0.0	0.0
PLATT MB #1	PUD	BAKKEN	29-30/33-32 154N-91W	0.066	0.055	26.92	01/2022	440.1	567.7	78.3	24.2	27.9	4.3	1,830.7	151.5	437.3	387.2	854.7	561.6	440.1	567.7	0.0	0.0
URAN - S XU. MB #1	PUD	BAKKEN	19-30 / 24-25 153N-91-92W	0.045	0.036	28.58	01/2024	439.5	566.5	78.2	16.0	18.4	2.8	1,194.8	98.3	302.3	282.4	511.9	263.1	439.5	566.5	0.0	0.0
URAN - S XU. TFK #1	PUD	THREE FORKS	19-30 / 24-25 153N-91-92W	0.045	0.036	27.83	01/2024	343.9	458.8	63.3	12.5	14.9	2.3	948.9	74.7	274.9	277.3	321.9	138.6	343.9	458.8	0.0	0.0
URAN MB #1 (E-W)	PUD	BAKKEN	13-24 /17to20 153N-91-92W	0.030	0.025	20.33	01/2024	550.1	609.6	84.1	13.6	13.5	2.1	947.5	85.0	174.2	245.4	443.0	277.3	550.1	609.6	0.0	0.0
URAN MB #1 (N-S)	PUD	BAKKEN	23-24/25-26 153N-92W	0.028	0.023	24.75	01/2024	313.3	399.4	55.1	7.2	8.2	1.3	528.9	42.6	148.1	153.6	184.5	92.7	313.3	399.4	0.0	0.0
URAN TFK #1 (E-W)	PUD	THREE FORKS	13-24 /17to20 153N-91-92W	0.030	0.025	30.58	01/2024	436.3	586.2	80.9	10.8	12.9	2.0	825.7	66.3	221.9	246.9	290.6	116.3	436.3	586.2	0.0	0.0
URAN TFK #2 (N-S)	PUD	THREE FORKS	23-24/25-26 153N-92W	0.028	0.023	13.17	01/2024	215.9	229.5	31.7	4.9	4.7	0.7	337.7	29.5	81.1	152.1	75.0	42.3	215.9	229.5	0.0	0.0
SUBTOTAL PUD-UNDRILLED								**17,699.7**	**22,512.7**	**3,106.8**	**414.7**	**473.4**	**73.1**	**30,965.7**	**2,547.4**	**7,751.0**	**8,020.6**	**12,646.7**	**7,173.4**	**17,699.7**	**22,512.7**	**0.0**	**0.0**
GRAND TOTAL PROVED								**44,239.0**	**77,490.9**	**10,693.7**	**1,884.8**	**2,739.3**	**422.8**	**149,702.6**	**10,314.8**	**49,309.4**	**16,461.9**	**73,616.5**	**46,349.2**	**101,133.1**	**81,194.2**	**56,894.1**	**3,703.3**

Scenario: SPR_1021ESC
Input Settings: SET1021

Zephyr Energy LLC
Proved Reserves Audit
Mountrail County, ND
Sproule September 30, 2021
Escalated Pricing
Total PDP

DATE : 11/19/2021
TIME : 14:48:12
DBS : BANKUS
SETTINGS : SET1021
SCENARIO : SPR_1021ESC

R E S E R V E S   A N D   E C O N O M I C S

EFF DATE: 10/2021
PW DATE: 10/2021

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	GROSS NGL PRODUCTION ---MBBLS---	NET OIL PRODUCTION ---MBBLS--	NET GAS PRODUCTION ----MMCF--	NET NGL PRODUCTION ---MBBLS--	NET OIL REVENUE ---M$---	NET GAS REVENUE ---M$---	NET NGL REVENUE ---M$---	TOTAL NET REVENUE ----M$----
12-2021	779.616	1730.857	238.858	42.543	68.107	10.513	2956.768	332.360	319.598	3608.727
12-2022	2540.572	5818.397	802.939	138.104	225.378	34.790	8907.709	879.876	988.034	10775.619
12-2023	2003.997	4676.540	645.363	108.009	178.671	27.580	6642.522	610.341	750.180	8003.042
12-2024	1677.593	3915.813	540.382	90.120	149.295	23.046	5362.112	473.564	608.403	6444.080
12-2025	1449.123	3381.435	466.638	77.649	128.647	19.858	4722.634	416.859	534.745	5674.236
12-2026	1278.592	2978.954	411.096	68.453	113.397	17.504	4255.750	374.082	480.806	5110.640
12-2027	1142.781	2658.050	366.811	61.189	101.327	15.641	3887.964	341.187	438.199	4667.352
12-2028	1027.636	2374.586	327.693	55.198	91.373	14.105	3584.564	313.914	403.052	4301.528
12-2029	928.824	2148.337	296.471	49.989	82.815	12.784	3317.752	290.171	372.615	3980.539
12-2030	845.736	1953.875	269.635	45.604	75.555	11.663	3093.330	269.895	346.761	3709.987
12-2031	771.748	1783.826	246.168	41.556	68.995	10.650	2880.267	251.176	322.959	3454.402
12-2032	699.869	1618.053	223.291	38.020	63.063	9.735	2692.800	234.173	301.096	3228.069
12-2033	636.111	1475.274	203.588	34.697	57.613	8.893	2511.119	218.213	280.575	3009.908
12-2034	580.724	1351.101	186.452	31.845	52.917	8.168	2354.946	204.433	262.858	2822.237
12-2035	530.450	1237.048	170.713	29.282	48.662	7.512	2212.553	191.758	246.560	2650.872
S TOT	16893.372	39102.144	5396.097	912.259	1505.816	232.441	59382.792	5402.003	6656.440	71441.240
AFTER	3298.634	7626.726	1052.488	185.386	317.301	48.979	15763.739	1399.067	1798.904	18961.712
TOTAL	20192.006	46728.872	6448.585	1097.646	1823.117	281.421	75146.528	6801.070	8455.345	90402.952

--END-- MO-YEAR	NET OIL PRICE -$/BBL-	NET GAS PRICE -$/MCF-	NET NGL PRICE -$/BBL-	SEVERANCE TAXES ----M$---	AD VALOREM TAXES -----M$---	NET OPER EXPENSE -----M$---	OPERATING CASH FLOW -----M$----	EQUITY INVESTMENT ----M$----	UNDISC NET CASH FLOW ----M$----	DISC NET CASH FLOW ----M$----
12-2021	69.50	4.88	30.40	300.323	0.000	694.058	2614.347	0.000	2614.347	2583.929
12-2022	64.50	3.90	28.40	873.103	0.000	2357.110	7545.409	14.574	7530.834	7031.916
12-2023	61.50	3.42	27.20	605.656	0.000	1976.692	5420.697	61.742	5358.955	4544.297
12-2024	59.50	3.17	26.40	459.981	0.000	1762.142	4221.956	1.934	4220.022	3253.072
12-2025	60.82	3.24	26.93	381.726	0.000	1619.842	3672.671	30.607	3642.064	2550.628
12-2026	62.17	3.30	27.47	321.943	0.000	1552.529	3236.168	0.000	3236.168	2060.972
12-2027	63.54	3.37	28.02	278.074	0.000	1506.554	2882.724	0.000	2882.724	1668.918
12-2028	64.94	3.44	28.58	245.229	0.000	1471.148	2585.152	1.759	2583.394	1359.521
12-2029	66.37	3.50	29.15	217.744	0.000	1433.180	2329.614	21.977	2307.638	1103.723
12-2030	67.83	3.57	29.73	195.642	0.000	1409.185	2105.161	0.000	2105.161	915.555
12-2031	69.31	3.64	30.32	175.994	0.000	1374.441	1903.969	45.715	1858.253	734.248
12-2032	70.83	3.71	30.93	164.000	0.000	1347.698	1716.370	17.307	1699.062	610.624
12-2033	72.37	3.79	31.55	147.106	0.000	1315.689	1547.112	33.011	1514.101	494.435
12-2034	73.95	3.86	32.18	136.170	0.000	1302.034	1384.033	3.391	1380.643	410.162
12-2035	75.56	3.94	32.82	125.496	0.000	1295.196	1230.179	1.215	1228.963	331.941
S TOT	65.09	3.59	28.64	4628.185	0.000	22417.498	44395.560	233.233	44162.328	29653.940
AFTER	85.03	4.41	36.73	894.695	0.000	11879.635	6187.382	2668.930	3518.453	804.709
TOTAL	68.46	3.73	30.05	5522.880	0.000	34297.132	50582.944	2902.162	47680.780	30458.650

	OIL	GAS	NGL
GROSS WELLS	179.0	0.0	
GROSS ULT., MB & MMF	75586.240	50432.136	6448.607
GROSS CUM., MB & MMF	55394.228	3703.260	0.021
GROSS RES., MB & MMF	20192.012	46728.876	6448.586
NET RES., MB & MMF	1097.646	1823.117	281.421
NET REVENUE, M$	75146.520	6801.069	8455.343
INITIAL PRICE, $	69.500	4.880	30.400
INITIAL N.I., PCT.	4.116	3.922	

METRICS	
LIFE, YRS.	35.92
PRIMARY DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	0.00
DISCOUNTED PAYOUT, YRS.	0.00
UNDISCOUNTED NET/INVEST.	17.43
DISCOUNTED NET/INVEST.	68.31
RATE OF RETURN, PCT.	25.00
INITIAL W.I., PCT.	5.140

PW %	PW M$
5.00	37142.996
6.00	35566.464
7.00	34123.268
8.00	32799.104
10.00	30458.664
12.00	28461.004
15.00	25968.366
17.50	24250.966
20.00	22787.142
25.00	20428.684

Zephyr Energy LLC
Proved Reserves Audit
Mountrail County, ND
Sproule September 30, 2021
Escalated Pricing
Total PNP

DATE : 11/19/2021
TIME : 14:48:13
DBS : BANKUS
SETTINGS : SET1021
SCENARIO : SPR_1021ESC

R E S E R V E S A N D E C O N O M I C S

EFF DATE: 10/2021
PW DATE: 10/2021

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	GROSS NGL PRODUCTION ---MBBLS---	NET OIL PRODUCTION ---MBBLS--	NET GAS PRODUCTION ----MMCF--	NET NGL PRODUCTION ---MBBLS--	NET OIL REVENUE ---M$---	NET GAS REVENUE ---M$---	NET NGL REVENUE ---M$---	TOTAL NET REVENUE ----M$----
12-2021	15.901	32.902	4.540	1.205	1.988	0.307	83.742	9.700	9.328	102.770
12-2022	72.648	146.446	20.210	5.860	9.313	1.438	377.939	36.358	40.827	455.125
12-2023	53.563	104.499	14.421	4.628	7.070	1.091	284.598	24.152	29.686	338.436
12-2024	43.921	83.912	11.580	3.945	5.899	0.911	234.698	18.713	24.041	277.452
12-2025	37.693	70.967	9.793	3.472	5.126	0.791	211.192	16.608	21.305	249.106
12-2026	33.171	61.818	8.531	3.112	4.556	0.703	193.464	15.031	19.319	227.813
12-2027	29.659	54.883	7.574	2.820	4.109	0.634	179.168	13.835	17.768	210.771
12-2028	26.769	49.291	6.802	2.569	3.733	0.576	166.825	12.824	16.465	196.114
12-2029	24.310	44.616	6.157	2.348	3.407	0.526	155.834	11.937	15.328	183.099
12-2030	22.181	40.621	5.606	2.151	3.120	0.482	145.905	11.144	14.318	171.367
12-2031	20.310	37.153	5.127	1.974	2.864	0.442	136.829	10.428	13.408	160.664
12-2032	18.650	34.105	4.706	1.814	2.635	0.407	128.503	9.785	12.582	150.870
12-2033	17.154	31.376	4.330	1.669	2.428	0.375	120.787	9.195	11.823	141.805
12-2034	15.781	28.876	3.985	1.535	2.237	0.345	113.546	8.642	11.112	133.301
12-2035	14.519	26.576	3.668	1.413	2.061	0.318	106.735	8.123	10.444	125.302
S TOT	446.230	848.041	117.030	40.514	60.546	9.346	2639.766	216.475	267.755	3123.996
AFTER	74.784	136.984	18.904	7.305	10.534	1.626	599.366	44.725	57.506	701.597
TOTAL	521.014	985.025	135.933	47.819	71.080	10.972	3239.133	261.200	325.261	3825.594

--END-- MO-YEAR	NET OIL PRICE -$/BBL-	NET GAS PRICE -$/MCF-	NET NGL PRICE -$/BBL-	SEVERANCE TAXES ----M$---	AD VALOREM TAXES -----M$---	NET OPER EXPENSE -----M$---	OPERATING CASH FLOW -----M$----	EQUITY INVESTMENT ----M$----	UNDISC NET CASH FLOW ----M$----	DISC NET CASH FLOW ----M$----
12-2021	69.50	4.88	30.40	9.355	0.000	21.150	72.265	51.196	21.069	20.733
12-2022	64.50	3.90	28.40	38.359	0.000	98.197	318.569	0.000	318.569	297.490
12-2023	61.50	3.42	27.20	20.931	0.000	84.327	233.179	0.000	233.179	197.742
12-2024	59.50	3.17	26.40	16.106	0.000	78.154	183.192	0.000	183.192	141.208
12-2025	60.82	3.24	26.93	13.282	0.000	75.284	160.540	0.000	160.540	112.460
12-2026	62.17	3.30	27.47	10.877	0.000	73.471	143.465	0.000	143.465	91.368
12-2027	63.54	3.37	28.02	10.061	0.000	72.282	128.428	0.000	128.428	74.353
12-2028	64.94	3.44	28.58	9.359	0.000	71.453	115.301	0.000	115.301	60.685
12-2029	66.37	3.50	29.15	8.736	0.000	70.875	103.488	0.000	103.488	49.517
12-2030	67.83	3.57	29.73	8.174	0.000	70.492	92.701	0.000	92.701	40.325
12-2031	69.31	3.64	30.32	7.661	0.000	70.269	82.733	0.000	82.733	32.719
12-2032	70.83	3.71	30.93	7.192	0.000	70.181	73.497	0.000	73.497	26.425
12-2033	72.37	3.79	31.55	6.757	0.000	70.207	64.841	0.000	64.841	21.195
12-2034	73.95	3.86	32.18	6.350	0.000	70.319	56.632	0.000	56.632	16.831
12-2035	75.56	3.94	32.82	5.967	0.000	70.511	48.825	0.000	48.825	13.193
S TOT	65.16	3.58	28.65	179.167	0.000	1067.171	1877.657	51.196	1826.461	1196.245
AFTER	82.04	4.25	35.37	33.394	0.000	513.976	154.228	118.170	36.058	16.426
TOTAL	67.74	3.67	29.64	212.561	0.000	1581.147	2031.884	169.366	1862.519	1212.671

	OIL	GAS	NGL
GROSS WELLS	5.0	0.0	
GROSS ULT., MB & MMF	2020.910	985.025	135.954
GROSS CUM., MB & MMF	1499.896	0.000	0.021
GROSS RES., MB & MMF	521.014	985.025	135.933
NET RES., MB & MMF	47.819	71.080	10.972
NET REVENUE, M$	3239.133	261.200	325.261
INITIAL PRICE, $	69.500	4.880	30.400
INITIAL N.I., PCT.	7.577	6.758	

METRICS	
LIFE, YRS.	22.92
PRIMARY DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	0.18
DISCOUNTED PAYOUT, YRS.	0.18
UNDISCOUNTED NET/INVEST.	12.00
DISCOUNTED NET/INVEST.	19.37
RATE OF RETURN, PCT.	25.00
INITIAL W.I., PCT.	8.914

PW %	PW M$
5.00	1476.181
6.00	1415.330
7.00	1358.919
8.00	1306.568
10.00	1212.671
12.00	1131.182
15.00	1027.861
17.50	955.706
20.00	893.653
25.00	792.793

Zephyr Energy LLC
Proved Reserves Audit
Mountrail County, ND
Sproule September 30, 2021
Escalated Pricing
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SETTINGS : SET1021
SCENARIO : SPR_1021ESC

R E S E R V E S   A N D   E C O N O M I C S

EFF DATE: 10/2021
PW DATE: 10/2021

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	GROSS NGL PRODUCTION ---MBBLS---	NET OIL PRODUCTION ---MBBLS--	NET GAS PRODUCTION ----MMCF--	NET NGL PRODUCTION ---MBBLS--	NET OIL REVENUE ---M$---	NET GAS REVENUE ---M$---	NET NGL REVENUE ---M$---	TOTAL NET REVENUE ----M$----
12-2021	68.448	52.212	7.205	0.811	0.553	0.085	56.355	2.698	2.595	61.649
12-2022	2294.388	1860.156	256.702	126.821	91.672	14.151	8179.943	357.887	401.880	8939.710
12-2023	826.271	823.259	113.610	45.721	40.660	6.276	2811.854	138.895	170.718	3121.468
12-2024	481.192	585.534	80.804	26.899	29.220	4.511	1600.468	92.687	119.078	1812.234
12-2025	332.648	493.315	68.077	18.732	24.804	3.829	1139.265	80.372	103.101	1322.738
12-2026	251.084	448.023	61.827	14.217	22.872	3.531	883.881	75.452	96.978	1056.311
12-2027	200.008	372.451	51.398	11.375	20.039	3.093	722.736	67.476	86.662	876.874
12-2028	165.245	309.209	42.671	9.431	16.637	2.568	612.438	57.157	73.387	742.981
12-2029	140.175	263.236	36.327	8.024	14.165	2.187	532.529	49.632	63.733	645.894
12-2030	121.307	228.499	31.533	6.961	12.297	1.898	472.170	43.927	56.437	572.533
12-2031	106.635	201.393	27.792	6.132	10.839	1.673	425.037	39.459	50.736	515.232
12-2032	94.926	179.694	24.798	5.469	9.672	1.493	387.376	35.914	46.178	469.468
12-2033	85.382	161.960	22.350	4.928	8.718	1.346	356.635	33.018	42.455	432.108
12-2034	77.465	147.214	20.316	4.478	7.924	1.223	331.118	30.614	39.363	401.094
12-2035	70.781	134.772	18.599	4.098	7.255	1.120	309.617	28.588	36.758	374.963
S TOT	5315.955	6260.928	864.008	294.095	317.327	48.983	18821.426	1133.776	1390.058	21345.258
AFTER	510.324	1003.374	138.466	30.506	54.361	8.391	2613.045	240.634	309.405	3163.084
TOTAL	5826.280	7264.302	1002.474	324.601	371.688	57.375	21434.470	1374.411	1699.463	24508.342

--END-- MO-YEAR	NET OIL PRICE -$/BBL-	NET GAS PRICE -$/MCF-	NET NGL PRICE -$/BBL-	SEVERANCE TAXES ----M$---	AD VALOREM TAXES -----M$---	NET OPER EXPENSE -----M$---	OPERATING CASH FLOW -----M$----	EQUITY INVESTMENT ----M$----	UNDISC NET CASH FLOW ----M$----	DISC NET CASH FLOW ----M$----
12-2021	69.50	4.88	30.40	5.924	0.000	5.750	49.975	4580.007	-4530.032	-4460.416
12-2022	64.50	3.90	28.40	862.968	0.000	938.470	7138.274	297.613	6840.662	6436.018
12-2023	61.50	3.42	27.20	300.380	0.000	429.586	2391.502	264.868	2126.634	1811.987
12-2024	59.50	3.17	26.40	173.480	0.000	320.637	1318.116	0.000	1318.116	1018.205
12-2025	60.82	3.24	26.93	125.531	0.000	244.354	952.852	0.000	952.852	668.480
12-2026	62.17	3.30	27.47	99.280	0.000	227.869	729.162	0.000	729.162	464.794
12-2027	63.54	3.37	28.02	81.986	0.000	212.640	582.249	0.000	582.249	337.336
12-2028	64.94	3.44	28.58	69.080	0.000	195.483	478.419	0.000	478.419	251.926
12-2029	66.37	3.50	29.15	33.690	0.000	183.532	428.672	0.000	428.672	205.114
12-2030	67.83	3.57	29.73	27.072	0.000	174.979	370.482	0.000	370.482	161.183
12-2031	69.31	3.64	30.32	24.354	0.000	168.748	322.130	0.000	322.130	127.394
12-2032	70.83	3.71	30.93	22.183	0.000	164.177	283.108	0.000	283.108	101.776
12-2033	72.37	3.79	31.55	20.410	0.000	160.837	250.862	0.000	250.862	81.981
12-2034	73.95	3.86	32.18	18.938	0.000	158.436	223.721	0.000	223.721	66.462
12-2035	75.56	3.94	32.82	17.697	0.000	156.769	200.496	0.000	200.496	54.146
S TOT	64.00	3.57	28.38	1882.971	0.000	3742.267	15720.021	5142.488	10577.533	7326.386
AFTER	85.66	4.43	36.87	148.960	0.000	1937.816	1076.307	227.312	848.995	178.094
TOTAL	66.03	3.70	29.62	2031.931	0.000	5680.083	16796.328	5369.800	11426.528	7504.480

	OIL	GAS	NGL
GROSS WELLS	13.0	0.0	
GROSS ULT., MB & MMF	5826.281	7264.302	1002.474
GROSS CUM., MB & MMF	0.000	0.000	0.000
GROSS RES., MB & MMF	5826.281	7264.302	1002.474
NET RES., MB & MMF	324.601	371.688	57.375
NET REVENUE, M$	21434.472	1374.411	1699.463
INITIAL PRICE, $	64.912	3.984	28.565
INITIAL N.I., PCT.	1.185	1.185	

METRICS	
LIFE, YRS.	27.17
PRIMARY DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	0.91
DISCOUNTED PAYOUT, YRS.	0.94
UNDISCOUNTED NET/INVEST.	3.13
DISCOUNTED NET/INVEST.	2.49
RATE OF RETURN, PCT.	25.00
INITIAL W.I., PCT.	6.745

PW %	PW M$
5.00	9060.344
6.00	8699.107
7.00	8365.750
8.00	8057.243
10.00	7504.480
12.00	7023.341
15.00	6407.408
17.50	5970.322
20.00	5587.620
25.00	4946.690

Zephyr Energy LLC
Proved Reserves Audit
Mountrail County, ND
Sproule September 30, 2021
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Total PUD-Undrilled

DATE : 11/19/2021
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DBS : BANKUS
SETTINGS : SET1021
SCENARIO : SPR_1021ESC

R E S E R V E S   A N D   E C O N O M I C S

EFF DATE: 10/2021
PW DATE: 10/2021

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	GROSS NGL PRODUCTION ---MBBLS---	NET OIL PRODUCTION ---MBBLS--	NET GAS PRODUCTION ----MMCF--	NET NGL PRODUCTION ---MBBLS--	NET OIL REVENUE ---M$---	NET GAS REVENUE ---M$---	NET NGL REVENUE ---M$---	TOTAL NET REVENUE ----M$----
12-2021	46.645	35.271	4.867	1.846	1.248	0.193	128.325	6.091	5.857	140.273
12-2022	2488.013	1982.808	273.628	42.115	30.493	4.707	2716.394	119.044	133.677	2969.116
12-2023	3891.586	3318.082	457.895	85.603	64.456	9.950	5264.600	220.181	270.628	5755.409
12-2024	3191.591	2991.065	412.767	86.704	70.142	10.827	5158.904	222.490	285.840	5667.234
12-2025	1542.224	1844.634	254.560	39.041	40.390	6.235	2374.476	130.876	167.887	2673.240
12-2026	1029.055	1522.532	210.109	25.435	32.615	5.035	1581.283	107.594	138.290	1827.168
12-2027	769.415	1366.124	188.525	18.797	28.978	4.473	1194.369	97.573	125.317	1417.258
12-2028	611.704	1193.223	164.665	14.845	25.643	3.958	964.050	88.096	113.111	1165.257
12-2029	505.796	1011.592	139.600	12.224	21.857	3.374	811.323	76.583	98.342	986.249
12-2030	429.897	859.794	118.652	10.361	18.526	2.860	702.817	66.179	85.026	854.023
12-2031	372.936	745.873	102.930	8.972	16.041	2.476	621.827	58.398	75.088	755.313
12-2032	328.685	657.370	90.717	7.897	14.119	2.179	559.289	52.429	67.412	679.130
12-2033	288.396	576.792	79.597	6.944	12.415	1.916	502.534	47.024	60.463	610.021
12-2034	256.222	512.444	70.717	6.234	11.147	1.721	461.017	43.063	55.370	559.450
12-2035	229.870	459.740	63.444	5.549	9.921	1.531	419.270	39.096	50.269	508.636
S TOT	15982.036	19077.344	2632.674	372.568	397.991	61.435	23460.478	1374.718	1732.579	26567.776
AFTER	1717.688	3435.377	474.082	42.161	75.383	11.636	3631.456	335.333	431.167	4397.958
TOTAL	17699.724	22512.720	3106.756	414.728	473.375	73.071	27091.934	1710.051	2163.746	30965.734

--END-- MO-YEAR	NET OIL PRICE -$/BBL-	NET GAS PRICE -$/MCF-	NET NGL PRICE -$/BBL-	SEVERANCE TAXES ----M$---	AD VALOREM TAXES -----M$---	NET OPER EXPENSE -----M$---	OPERATING CASH FLOW -----M$----	EQUITY INVESTMENT ----M$----	UNDISC NET CASH FLOW ----M$----	DISC NET CASH FLOW ----M$----
12-2021	69.50	4.88	30.40	13.483	0.000	13.131	113.659	1681.035	-1567.376	-1546.612
12-2022	64.50	3.90	28.40	286.599	0.000	332.220	2350.296	3260.109	-909.813	-714.548
12-2023	61.50	3.42	27.20	556.887	0.000	735.827	4462.695	2454.006	2008.689	1820.001
12-2024	59.50	3.17	26.40	548.136	0.000	827.275	4291.824	171.794	4120.030	3201.424
12-2025	60.82	3.24	26.93	255.005	0.000	506.983	1911.252	128.910	1782.342	1253.304
12-2026	62.17	3.30	27.47	171.849	0.000	399.634	1255.684	0.000	1255.684	801.226
12-2027	63.54	3.37	28.02	130.429	0.000	334.845	951.985	0.000	951.985	551.803
12-2028	64.94	3.44	28.58	105.424	0.000	296.132	763.702	0.000	763.702	402.280
12-2029	66.37	3.50	29.15	74.310	0.000	277.062	634.877	0.000	634.877	303.914
12-2030	67.83	3.57	29.73	50.037	0.000	260.545	543.441	0.000	543.441	236.452
12-2031	69.31	3.64	30.32	36.911	0.000	248.973	469.428	0.000	469.428	185.661
12-2032	70.83	3.71	30.93	32.072	0.000	240.714	406.345	0.000	406.345	146.098
12-2033	72.37	3.79	31.55	28.798	0.000	226.203	355.020	15.225	339.795	110.869
12-2034	73.95	3.86	32.18	26.401	0.000	219.563	313.486	5.658	307.828	91.505
12-2035	75.56	3.94	32.82	23.995	0.000	205.536	279.105	12.910	266.195	71.754
S TOT	62.97	3.45	28.20	2340.335	0.000	5124.641	19102.800	7729.646	11373.153	6915.133
AFTER	86.13	4.45	37.05	207.066	0.000	2626.365	1564.525	290.961	1273.564	258.275
TOTAL	65.32	3.61	29.61	2547.401	0.000	7751.006	20667.326	8020.608	12646.717	7173.408

	OIL	GAS	NGL
GROSS WELLS	47.0	0.0	
GROSS ULT., MB & MMF	17699.722	22512.720	3106.755
GROSS CUM., MB & MMF	0.000	0.000	0.000
GROSS RES., MB & MMF	17699.722	22512.720	3106.755
NET RES., MB & MMF	414.728	473.375	73.071
NET REVENUE, M$	27091.934	1710.051	2163.746
INITIAL PRICE, $	62.920	3.670	27.768
INITIAL N.I., PCT.	3.958	3.958	

METRICS	
LIFE, YRS.	30.58
PRIMARY DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	2.36
DISCOUNTED PAYOUT, YRS.	2.39
UNDISCOUNTED NET/INVEST.	2.58
DISCOUNTED NET/INVEST.	2.05
RATE OF RETURN, PCT.	25.00
INITIAL W.I., PCT.	2.757

PW %	PW M$
5.00	9305.055
6.00	8804.427
7.00	8345.252
8.00	7922.944
10.00	7173.407
12.00	6529.559
15.00	5719.312
17.50	5155.720
20.00	4671.453
25.00	3883.399

Zephyr Energy LLC
Proved Reserves Audit
Mountrail County, ND
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Grand Total Proved

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DBS : BANKUS
SETTINGS : SET1021
SCENARIO : SPR_1021ESC

R E S E R V E S   A N D   E C O N O M I C S

EFF DATE: 10/2021
PW DATE: 10/2021

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	GROSS NGL PRODUCTION ---MBBLS---	NET OIL PRODUCTION ---MBBLS--	NET GAS PRODUCTION ----MMCF--	NET NGL PRODUCTION ---MBBLS--	NET OIL REVENUE ---M$---	NET GAS REVENUE ---M$---	NET NGL REVENUE ---M$---	TOTAL NET REVENUE ----M$----
12-2021	910.610	1851.242	255.471	46.406	71.895	11.098	3225.191	350.850	337.378	3913.419
12-2022	7395.621	9807.807	1353.478	312.899	356.856	55.085	20181.984	1393.166	1564.418	23139.570
12-2023	6775.418	8922.380	1231.288	243.961	290.858	44.898	15003.574	993.570	1221.213	17218.354
12-2024	5394.298	7576.324	1045.533	207.667	254.557	39.294	12356.182	807.455	1037.363	14201.000
12-2025	3361.689	5790.351	799.068	138.895	198.966	30.713	8447.566	644.715	827.038	9919.320
12-2026	2591.902	5011.328	691.564	111.217	173.441	26.773	6914.377	572.160	735.393	8221.932
12-2027	2141.863	4451.508	614.308	94.181	154.452	23.842	5984.237	520.071	667.946	7172.256
12-2028	1831.354	3926.310	541.831	82.043	137.385	21.207	5327.878	471.990	606.014	6405.880
12-2029	1599.105	3467.781	478.554	72.585	122.244	18.870	4817.438	428.323	550.019	5795.780
12-2030	1419.120	3082.788	425.425	65.078	109.498	16.902	4414.223	391.145	502.542	5307.911
12-2031	1271.630	2768.246	382.018	58.635	98.740	15.242	4063.960	359.461	462.191	4885.612
12-2032	1142.130	2489.223	343.513	53.200	89.490	13.814	3767.968	332.300	427.268	4527.537
12-2033	1027.043	2245.402	309.865	48.237	81.174	12.530	3491.076	307.450	395.315	4193.842
12-2034	930.193	2039.635	281.470	44.092	74.224	11.457	3260.628	286.752	368.702	3916.082
12-2035	845.620	1858.137	256.423	40.342	67.900	10.481	3048.176	267.564	344.031	3659.773
S TOT	38637.596	65288.460	9009.809	1619.436	2281.680	352.206	104304.456	8126.972	10046.832	122478.272
AFTER	5601.431	12202.460	1683.940	265.358	457.580	70.633	22607.608	2019.760	2596.982	27224.348
TOTAL	44239.028	77490.920	10693.749	1884.795	2739.260	422.839	126912.064	10146.732	12643.814	149702.624

--END-- MO-YEAR	NET OIL PRICE -$/BBL-	NET GAS PRICE -$/MCF-	NET NGL PRICE -$/BBL-	SEVERANCE TAXES ----M$---	AD VALOREM TAXES -----M$---	NET OPER EXPENSE -----M$---	OPERATING CASH FLOW -----M$----	EQUITY INVESTMENT ----M$----	UNDISC NET CASH FLOW ----M$----	DISC NET CASH FLOW ----M$----
12-2021	69.50	4.88	30.40	329.085	0.000	734.088	2850.246	6312.238	-3461.992	-3402.365
12-2022	64.50	3.90	28.40	2061.028	0.000	3725.997	17352.548	3572.296	13780.252	13050.876
12-2023	61.50	3.42	27.20	1483.854	0.000	3226.431	12508.072	2780.616	9727.457	8374.028
12-2024	59.50	3.17	26.40	1197.703	0.000	2988.207	10015.090	173.728	9841.362	7613.908
12-2025	60.82	3.24	26.93	775.544	0.000	2446.463	6697.314	159.517	6537.797	4584.873
12-2026	62.17	3.30	27.47	603.948	0.000	2253.504	5364.480	0.000	5364.480	3418.360
12-2027	63.54	3.37	28.02	500.550	0.000	2126.321	4545.386	0.000	4545.386	2632.410
12-2028	64.94	3.44	28.58	429.091	0.000	2034.216	3942.574	1.759	3940.816	2074.413
12-2029	66.37	3.50	29.15	334.479	0.000	1964.650	3496.652	21.977	3474.675	1662.268
12-2030	67.83	3.57	29.73	280.925	0.000	1915.200	3111.786	0.000	3111.786	1353.514
12-2031	69.31	3.64	30.32	244.921	0.000	1862.432	2778.260	45.715	2732.545	1080.021
12-2032	70.83	3.71	30.93	225.447	0.000	1822.770	2479.318	17.307	2462.011	884.923
12-2033	72.37	3.79	31.55	203.070	0.000	1772.936	2217.835	48.236	2169.599	708.480
12-2034	73.95	3.86	32.18	187.859	0.000	1750.351	1977.872	9.048	1968.824	584.960
12-2035	75.56	3.94	32.82	173.155	0.000	1728.012	1758.605	14.126	1744.479	471.034
S TOT	64.41	3.56	28.53	9030.658	0.000	32351.578	81096.048	13156.563	67939.480	45091.700
AFTER	85.20	4.41	36.77	1284.115	0.000	16957.790	8982.443	3305.372	5677.072	1257.505
TOTAL	67.33	3.70	29.90	10314.773	0.000	49309.368	90078.488	16461.935	73616.552	46349.204

	OIL	GAS	NGL
GROSS WELLS	244.0	0.0	
GROSS ULT., MB & MMF	101133.152	81194.192	10693.768
GROSS CUM., MB & MMF	56894.124	3703.260	0.021
GROSS RES., MB & MMF	44239.024	77490.928	10693.747
NET RES., MB & MMF	1884.794	2739.260	422.839
NET REVENUE, M$	126912.064	10146.732	12643.815
INITIAL PRICE, $	63.620	3.822	28.125
INITIAL N.I., PCT.	4.116	3.922	

METRICS	
LIFE, YRS.	35.92
PRIMARY DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	0.50
DISCOUNTED PAYOUT, YRS.	0.51
UNDISCOUNTED NET/INVEST.	5.47
DISCOUNTED NET/INVEST.	4.74
RATE OF RETURN, PCT.	25.00
INITIAL W.I., PCT.	3.867

PW %	PW M$
5.00	56984.576
6.00	54485.328
7.00	52193.192
8.00	50085.860
10.00	46349.224
12.00	43145.088
15.00	39122.948
17.50	36332.712
20.00	33939.868
25.00	30051.564

APPENDIX B: ABBREVIATIONS

This appendix contains a list of abbreviations found in Sproule reports, as well as a table comparing Imperial and Metric units. Two conversion tables, used to prepare this report, are also provided.

AOF	absolute open flow
ARTC	Alberta Royalty Tax Credit
BOE	barrels of oil equivalent
bopd	barrels of oil per day
bwpd	barrels of water per day
Cr	Crown
DCQ	daily contract quantity
DSU	drilling spacing unit
DUC	drilled uncompleted
FH	Freehold
GCA	gas cost allowance
GOR	gas-oil ratio
GORR	gross overriding royalty
LPG	liquid petroleum gas
M	Millions
MMZAR	Millions of South African ZAR’s
m	thousands
mcfd	thousands of cubic feet per day
Mcfpd	thousands of cubic feet per day
MPR	maximum permissive rate
MRL	maximum rate limitation
NC	‘new’ Crown
NCI	net carried interest
NGL	natural gas liquids
NORR	net overriding royalty
NPI	net profits interest
OC	‘old’ Crown
ORRI	overriding royalty interest
P&NG	petroleum and natural gas
PSU	production spacing unit
PVT	pressure-volume-temperature
TCGSL	TransCanada Gas Services Limited
UOCR	Unit Operating Cost Rates for operating gas cost allowance
WI	working interest

Imperial Units			Metric Units	
M (10^3)	thousand	**Prefixes**	k (10^3)	kilo
MM (10^6)	million		M (10^6)	mega
B (10^9)	billion		G (10^9)	giga
T (10^{12})	trillion		T (10^{12})	tera
Q (10^{15})	quadrillion		P (10^{15})	peta
in.	inches	**Length**	cm	centimetres
ft	feet		m	metres
mi	miles		km	kilometres
ft^2	square feet	**Area**	m^2	square metres
ac	acres		ha	hectares
cf or ft^3	cubic feet	**Volume**	m^3	cubic metres
scf	standard cubic feet			
gal	gallons		L	litres
Mcf	thousand cubic feet			
MMcf	million cubic feet			
Bcf	billion cubic feet		e^6m^3	million cubic metres
bbl	barrels		m^3	cubic metres
Mbbl	thousand barrels		e^3m^3	thousand cubic metres
stb	stock tank barrels		stm^3	stock tank cubic metres
bbl/d	barrels per day	**Rate**	m^3/d	cubic metre per day
Mbbl/d	thousand barrels per day		e^3m^3/d	thousand cubic metres
Mcf/d	thousand cubic feet per day		e^3m^3/d	thousand cubic metres
MMcf/d	million cubic feet per day		e^6m^3/d	million cubic metres
Btu	British thermal units	**Energy**	J	joules
oz	ounces	**Mass**	g	grams
lb	pounds		kg	kilograms
ton	tons		t	tonnes
lt	long tons			
psi	pounds per square inch	**Pressure**	Pa	pascals
			kPa	kilopascals (10^3)
psia	pounds per square inch absolute			
psig	pounds per square inch gauge			
°F	degrees Fahrenheit	**Temperature**	°C	degrees Celsius
°R	degrees Rankine		K	degrees Kelvin
M$	thousand dollars	**Dollars**	k$	1 kilodollar

Imperial Units		Time	Metric Units	
sec	second	**Time**	s	second
min	minute		min	minute
hr	hour		h	hour
d	day		d	day
wk	week			week
mo	month			month
yr	year		a	annum

Sproule

Conversion Factors — Metric to Imperial		
cubic metres (m^3) (@ 15°C)	x 6.29010	= barrels (bbl) (@ 60°F), water
m^3 (@ 15°C)	x 6.3300	= bbl (@ 60°F), Ethane
m^3 (@ 15°C)	x 6.30001	= bbl (@ 60°F), Propane
m^3 (@ 15°C)	x 6.29683	= bbl (@ 60°F), Butanes
m^3 (@ 15°C)	x 6.29287	= bbl (@ 60°F), oil, Pentanes Plus
m^3 (@ 101.325 kPaa, 15°C)	x 0.0354937	= thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F)
1,000 cubic metres (10^3m^3) (@ 101.325 kPaa, 15°C)	x 35.49373	= Mcf (@ 14.65 psia, 60°F)
hectares (ha)	x 2.4710541	= acres
1,000 square metres (10^3m^2)	x 0.2471054	= acres
10,000 cubic metres (ha·m)	x 8.107133	= acre feet (ac-ft)
$m^3/10^3m^3$ (@ 101.325 kPaa, 15° C)	x 0.0437809	= Mcf/Ac.ft. (@ 14.65 psia, 60°F)
joules (j)	x 0.000948213	= Btu
megajoules per cubic metre (MJ/m^3) (@ 101.325 kPaa, 15°C)	x 26.714952	= British thermal units per standard cubic foot (Btu/scf) (@ 14.65 psia, 60°F)
dollars per gigajoule ($/GJ)	x 1.054615	= $/Mcf (1,000 Btu gas)
metres (m)	x 3.28084	= feet (ft)
kilometres (km)	x 0.6213712	= miles (mi)
dollars per 1,000 cubic metres ($\$/10^3m^3$)	x 0.0288951	= dollars per thousand cubic feet ($/Mcf) (@ 15.025 psia) B.C.
($\$/10^3m^3$)	x 0.02817399	= $/Mcf (@ 14.65 psia) Alta.
dollars per cubic metre ($\$/m^3$)	x 0.158910	= dollars per barrel ($/bbl)
gas/oil ratio (GOR) (m^3/m^3)	x 5.640309	= GOR (scf/bbl)
kilowatts (kW)	x 1.341022	= horsepower
kilopascals (kPa)	x 0.145038	= psi
tonnes (t)	x 0.9842064	= long tons (LT)
kilograms (kg)	x 2.204624	= pounds (lb)
litres (L)	x 0.2199692	= gallons (Imperial)
litres (L)	x 0.264172	= gallons (U.S.)
cubic metres per million cubic metres ($m^3/10^6m^3$) (C_3)	x 0.177496	= barrels per million cubic feet (bbl/MMcf) (@ 14.65 psia)
$m^3/10^6m^3$) (C_4)	x 0.1774069	= bbl/MMcf (@ 14.65 psia)
$m^3/10^6m^3$) (C_{5+})	x 0.1772953	= bbl/MMcf (@ 14.65 psia)
tonnes per million cubic metres ($t/10^6m^3$) (sulphur)	x 0.0277290	= LT/MMcf (@ 14.65 psia)
millilitres per cubic meter (mL/m^3) (C_{5+})	x 0.0061974	= gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf)
(mL/m^3) (C_{5+})	x 0.0074428	= gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf)
Kelvin (K)	x 1.8	= degrees Rankine (°R)
millipascal seconds (mPa·s)	x 1.0	= centipoise
density (kg/m3), ρ	ρ÷1000x141.5-131.5	= °API

Sproule

Conversion Factors — Imperial to Metric		
barrels (bbl) (@ 60°F)	x 0.15898	= cubic metres (m^3) (@ 15°C), water
bbl (@ 60°F)	x 0.15798	= m^3 (@ 15°C), Ethane
bbl (@ 60°F)	x 0.15873	= m^3 (@ 15°C), Propane
bbl (@ 60°F)	x 0.15881	= m^3 (@ 15°C), Butanes
bbl (@ 60°F)	x 0.15891	= m^3 (@ 15°C), oil, Pentanes Plus
thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F)	x 28.17399	= m^3 (@ 101.325 kPaa, 15°C)
Mcf (@ 14.65 psia, 60°F)	x 0.02817399	= 1,000 cubic metres (10^3m^3) (@ 101.325 kPaa, 15°C)
acres	x 0.4046856	= hectares (ha)
acres	x 4.046856	= 1,000 square metres (10^3m^2)
acre feet (ac-ft)	x 0.123348	= 10,000 cubic metres (10^4m^3) (ha˙m)
Mcf/ac-ft (@ 14.65 psia, 60°F)	x 22.841028	= $10^3m^3/m^3$ (@ 101.325 kPaa, 15°C)
Btu	x 1054.615	= joules (J)
British thermal units per standard cubic foot (Btu/Scf)	x 0.03743222	= megajoules per cubic metre (MJ/m^3)
(@ 14.65 psia, 60°F)		(@ 101.325 kPaa, 15°C)
$/Mcf (1,000 Btu gas)	x 0.9482133	= dollars per gigajoule ($/GJ)
$/Mcf (@ 14.65 psia, 60°F) Alta.	x 35.49373	= $/$10^3m^3$ (@ 101.325 kPaa, 15°C)
$/Mcf (@ 15.025 psia, 60°F), B.C.	x 34.607860	= $/$10^3m^3$ (@ 101.325 kPaa, 15°C)
feet (ft)	x 0.3048	= metres (m)
miles (mi)	x 1.609344	= kilometres (km)
dollars per barrel ($/bbl)	x 6.29287	= dollars per cubic metre ($/$m^3$)
GOR (scf/bbl)	x 0.177295	= gas/oil ratio (GOR) (m^3/m^3)
horsepower	x 0.7456999	= kilowatts (kW)
psi	x 6.894757	= kilopascals (kPa)
long tons (LT)	x 1.016047	= tonnes (t)
pounds (lb)	x 0.453592	= kilograms (kg)
gallons (Imperial)	x 4.54609	= litres (L) (.001 m^3)
gallons (U.S.)	x 3.785412	= litres (L) (.001 m^3)
barrels per million cubic feet (bbl/MMcf) (@ 14.65 psia) (C_3)	x 5.6339198	= cubic metres per million cubic metres ($m^3/10^6m^3$)
bbl/MMcf (C_4)	x 5.6367593	= ($m^3/10^6m^3$)
bbl/MMcf (C_{5+})	x 5.6403087	= ($m^3/10^6m^3$)
LT/MMcf (sulphur)	x 36.063298	= tonnes per million cubic metres ($t/10^6m^3$)
gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf) (C_{5+})	x 161.3577	= millilitres per cubic meter (mL/m^3)
gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf) (C_{5+})	x 134.3584	= (mL/m^3)
degrees Rankine (°R)	x 0.555556	= Kelvin (K)
centipoises	x 1.0	= millipascal seconds (mPa˙s)
°API	(°APIx131.5)x 1000/141.5	= density (kg/m3)

Conversion Factors — Metric to Imperial		
cubic metres (m^3) (@ 15°C)	x 6.29010	= barrels (bbl) (@ 60°F), water
m^3 (@ 15°C)	x 6.3300	= bbl (@ 60°F), Ethane
m^3 (@ 15°C)	x 6.30001	= bbl (@ 60°F), Propane
m^3 (@ 15°C)	x 6.29683	= bbl (@ 60°F), Butanes
m^3 (@ 15°C)	x 6.29287	= bbl (@ 60°F), oil, Pentanes Plus
m^3 (@ 101.325 kPaa, 15°C)	x 0.0354937	= thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F)
1,000 cubic metres (10^3m^3) (@ 101.325 kPaa, 15°C)	x 35.49373	= Mcf (@ 14.65 psia, 60°F)
hectares (ha)	x 2.4710541	= acres
1,000 square metres (10^3m^2)	x 0.2471054	= acres
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$m^3/10^3m^3$ (@ 101.325 kPaa, 15° C)	x 0.0437809	= Mcf/Ac.ft. (@ 14.65 psia, 60°F)
joules (j)	x 0.000948213	= Btu
megajoules per cubic metre (MJ/m^3) (@ 101.325 kPaa, 15°C)	x 26.714952	= British thermal units per standard cubic foot (Btu/scf) (@ 14.65 psia, 60°F)
dollars per gigajoule ($/GJ)	x 1.054615	= $/Mcf (1,000 Btu gas)
metres (m)	x 3.28084	= feet (ft)
kilometres (km)	x 0.6213712	= miles (mi)
dollars per 1,000 cubic metres ($\$/10^3m^3$)	x 0.0288951	= dollars per thousand cubic feet ($/Mcf) (@ 15.025 psia) B.C.
($\$/10^3m^3$)	x 0.02817399	= $/Mcf (@ 14.65 psia) Alta.
dollars per cubic metre ($\$/m^3$)	x 0.158910	= dollars per barrel ($/bbl)
gas/oil ratio (GOR) (m^3/m^3)	x 5.640309	= GOR (scf/bbl)
kilowatts (kW)	x 1.341022	= horsepower
kilopascals (kPa)	x 0.145038	= psi
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$m^3/10^6m^3$) (C_4)	x 0.1774069	= bbl/MMcf (@ 14.65 psia)
$m^3/10^6m^3$) (C_{5+})	x 0.1772953	= bbl/MMcf (@ 14.65 psia)
tonnes per million cubic metres ($t/10^6m^3$) (sulphur)	x 0.0277290	= LT/MMcf (@ 14.65 psia)
millilitres per cubic meter (mL/m^3) (C_{5+})	x 0.0061974	= gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf)
(mL/m^3) (C_{5+})	x 0.0074428	= gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf)
Kelvin (K)	x 1.8	= degrees Rankine (°R)
millipascal seconds (mPa·s)	x 1.0	= centipoise
density (kg/m3), ρ	ρ÷1000x141.5-131.5	= °API

APPENDIX C: PRMS GUIDANCE

The following is an excerpt of the Resources Classification and Categorization Guidelines from the Petroleum Resources Management System 2018, sponsored by Society of Petroleum Engineers ("SPE"), World Petroleum Council ("WPC"), American Association of Petroleum Geologists ("AAPG"), Society of Petroleum Evaluation Engineers ("SPEE"), Society of Exploration Geophysicists ("SEG"), Society of Petrophysicists and Well Log Analysts ("SPWLA"), and the European Association of Geoscientists & Engineers ("EAGE").

2.0 Classification and Categorization Guidelines

2.0.0.1 To consistently characterize petroleum projects, evaluations of all resources should be conducted in the context of the full classification *system* shown in Figure 1.1. These guidelines reference this classification system and support an evaluation in which projects are "classified" based on their chance of commerciality, P_c (the vertical axis labeled Chance of Commerciality), and estimates of recoverable and marketable quantities associated with each project are "categorized" to reflect uncertainty (the horizontal axis). The actual workflow of classification versus categorization varies with individual projects and is often an iterative analysis leading to a final report. Report here refers to the presentation of evaluation results within the entity conducting the assessment and should not be construed as replacing requirements for public disclosures under guidelines established by regulatory and/or other government agencies.

2.1 Resources Classification

2.1.0.1 The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

2.1.1 Determination of Discovery Status

2.1.1.1 A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

2.1.1.2 Where a discovery has identified recoverable hydrocarbons, but is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

2.1.2.1 Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

A. Evidence of a technically mature, feasible development plan.

B. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.

C. Evidence to support a reasonable time-frame for development.

D. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see Section 3.1.1, Net Cash-Flow Evaluation).

E. A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, CO_2) can be sold, stored, re-injected, or otherwise appropriately disposed.

F. Evidence that the necessary production and transportation facilities are available or can be made available.

G. Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

2.1.2.2 The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the *2P* Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

2.1.2.3 To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section 2.1.2.1. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

2.1.2.4 While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

2.1.3 Project Status and Chance of Commerciality

2.1.3.1 Evaluators have the option to establish a more detailed resources classification reporting system that can also provide the basis for portfolio management by subdividing the chance of commerciality axis according to project maturity. Such sub-classes may be characterized qualitatively by the project maturity level descriptions and associated quantitative chance of reaching commercial status and being placed on production.

2.1.3.2 As a project moves to a higher level of commercial maturity in the classification (see Figure 1.1 vertical axis), there will be an increasing chance that the accumulation will be commercially developed and the project quantities move to Reserves. For Contingent and Prospective Resources, this is further expressed as a chance of commerciality, P_c, which incorporates the following underlying chance component(s):

A. The chance that the potential accumulation will result in the discovery of a significant quantity of petroleum, which is called the "chance of geologic discovery," P_g.

B. Once discovered, the chance that the known accumulation will be commercially developed is called the "chance of development," P_d.

2.1.3.3 There must be a high degree of certainty in the chance of commerciality, P_c, for Reserves to be assigned; for Contingent Resources, $P_c = P_d$; and for Prospective Resources, P_c is the product of P_g and P_d.

2.1.3.4 Contingent and Prospective Resources can have different project scopes (e.g., well count, development spacing, and facility size) as development uncertainties and project definition mature.

2.1.3.5 Project Maturity Sub-Classes

2.1.3.5.1 As Figure 2.1 illustrates, development projects and associated recoverable quantities may be sub-classified according to project maturity levels and the associated actions (i.e., business decisions) required to move a project toward commercial production.

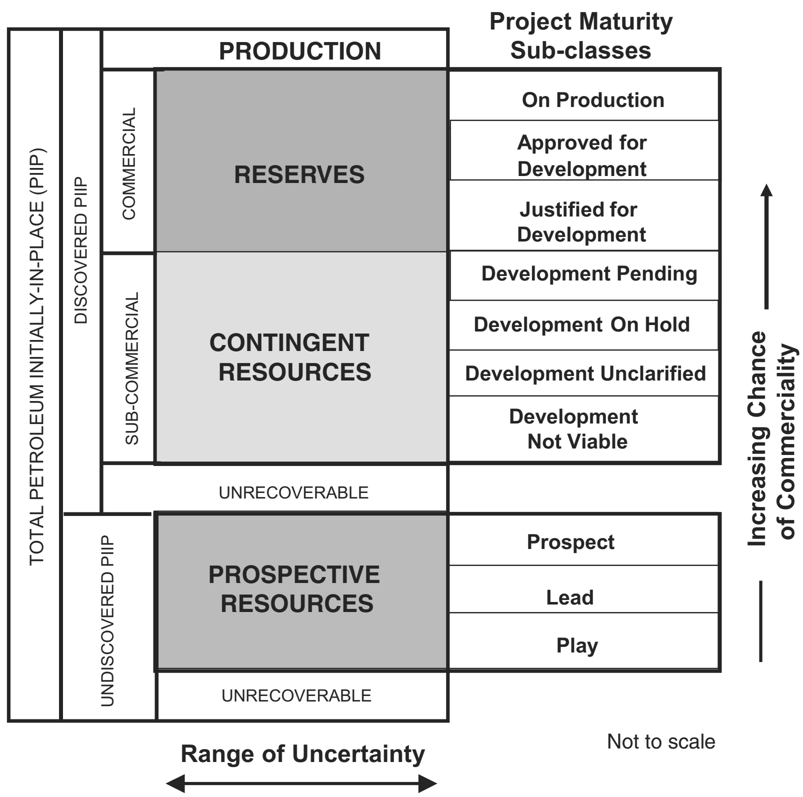

Figure 2.1—Sub-classes based on project maturity

2.1.3.5.2. Maturity terminology and definitions for each project maturity class and sub-class are provided in Table I. This approach supports the management of portfolios of opportunities at various stages of exploration, appraisal, and development. Reserve sub-classes must achieve commerciality while Contingent and Prospective Resources sub-classes may be supplemented by associated quantitative estimates of chance of commerciality to mature.

2.1.3.5.3 Resources sub-class maturation is based on those actions that progress a project through final approvals to implementation and initiation of production and product sales. The boundaries between different levels of project maturity are frequently referred to as project “decision gates.”

2.1.3.5.4 Projects that are classified as Reserves must meet the criteria as listed in Section 2.1.2, Determination of Commerciality. Projects sub-classified as Justified for Development are agreed upon by the managing entity and partners as commercially viable and have support to advance the project, which includes a firm intent to proceed with development. All participating entities have agreed to the project and there are no known contingencies to the project from any official entity that will have to formally approve the project.

2.1.3.5.5 Justified for Development Reserves are reclassified to Approved for Development after a FID has been made. Projects should not remain in the Justified for Development sub-class for extended time periods without positive indications that all required approvals are expected to be obtained without undue delay. If there is no longer the reasonable expectation of project execution (i.e., historical track record of execution, project progress), the project shall be reclassified as Contingent Resources.

2.1.3.5.6 Projects classified as Contingent Resources have their sub-classes aligned with the entity’s plan to manage its portfolio of projects. Thus, projects on known accumulations that are actively being studied, undergoing feasibility review, and have planned near-term operations (e.g., drilling) are placed in Contingent Resources Development Pending, while those that do not meet this test are placed into either Contingent Resources On Hold, Unclarified, or Not Viable.

2.1.3.5.7 Where commercial factors change and there is a significant risk that a project with Reserves will no longer proceed, the project shall be reclassified as Contingent Resources.

2.1.3.5.8 For Contingent Resources, evaluators should focus on gathering data and performing analyses to clarify and then mitigate those key conditions or contingencies that prevent commercial development. Note that the Contingent Resources sub-classes described above and shown in Figure 2.1 are recommended; however, entities are at liberty to introduce additional sub-classes that align with project management goals.

2.1.3.5.9 For Prospective Resources, potential accumulations may mature from Play, to Lead and then to Prospect based on the ability to identify potentially commercially viable exploration projects. The Prospective Resources are evaluated according to chance of geologic discovery, P_g, and chance of development, P_d, which together determine the chance of commerciality, P_c. Commercially recoverable quantities under appropriate development projects are then estimated. The decision at each exploration phase is whether to undertake further data acquisition and/or studies designed to move the Play through to a drillable Prospect with a project description range commensurate with the Prospective Resources sub-class.

2.1.3.6 Reserves Status

2.1.3.6.1 Once projects satisfy commercial maturity (criteria given in Table 1), the associated quantities are classified as Reserves. These quantities may be allocated to the following subdivisions based on the funding and operational status of wells and associated facilities within the reservoir development plan (Table 2 provides detailed definitions and guidelines):

A. **Developed Reserves** are quantities expected to be recovered from existing wells and facilities.

   1. **Developed Producing Reserves** are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

2. **Developed Non-Producing Reserves** include shut-in and behind-pipe reserves with minor costs to access.

B. **Undeveloped Reserves** are quantities expected to be recovered through future significant investments.

2.1.3.6.2 The distinction between the “minor costs to access” Developed Non-Producing Reserves and the “significant investment” needed to develop Undeveloped Reserves requires the judgment of the evaluator taking into account the cost environment. A significant investment would be a relatively large expenditure when compared to the cost of drilling and completing a new well. A minor cost would be a lower expenditure when compared to the cost of drilling and completing a new well.

2.1.3.6.3 Once a project passes the commercial assessment and achieves Reserves status, it is then included with all other Reserves projects of the same category in the same field for estimating combined future production and applying the economic limit test (see Section 3.1, Assessment of Commerciality).

2.1.3.6.4 Where Reserves remain Undeveloped beyond a reasonable time-frame or have remained Undeveloped owing to postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and to justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay (see Section 2.1.2, Determination of Commerciality) is justified, a reasonable time-frame to commence the project is generally considered to be less than five years from the initial classification date.

2.1.3.6.5 Development and Production status are of significant importance for project portfolio management and financials. The Reserves status concept of Developed and Undeveloped status is based on the funding and operational status of wells and producing facilities within the development project. These status designations are applicable throughout the full range of Reserves uncertainty categories (1P, 2P, and 3P or Proved, Probable, and Possible). Even those projects that are Developed and On Production should have remaining uncertainty in recoverable quantities.

2.1.3.7 Economic Status

2.1.3.7.1 Projects may be further characterized by economic status. All projects classified as Reserves must be commercial under defined conditions (see Section 3.1, Assessment of Commerciality Assessment). Based on assumptions regarding future conditions and the impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

A. **Economically Viable Contingent Resources** are those quantities associated with technically feasible projects where cash flows are positive under reasonably forecasted conditions but are not Reserves because it does not meet the commercial criteria defined in Section 2.1.2.

B. **Economically Not Viable Contingent Resources** are those quantities for which development projects are not expected to yield positive cash flows under reasonable forecast conditions.

2.1.3.7.2 The best estimate (or P50) production forecast is typically used for the economic evaluation for the commercial assessment of the project. The low case, when used as the primary case for a project decision, may be used to determine project economics. The economic evaluation of the project high case alone is not permitted to be used in the determination of the project’s commerciality.

2.1.3.7.3 For Reserves, the best estimate production forecast reflects a specific development scenario recovery process, a certain number and type of wells, facilities, and infrastructure.

2.1.3.7.4 The project's low-case scenario is tested to ensure it is economic, which is required for Proved Reserves to exist (see Section 2.2.2, Category Definitions and Guidelines). It is recommended to evaluate the low case and the high case (which will quantify the 3P Reserves) to convey the project downside risk and upside potential. The project development scenarios may vary in the number and type of wells, facilities, and infrastructure in Contingent Resources, but to recognize Reserves, there must exist the reasonable expectation to develop the project for the best-estimate case.

2.1.3.7.5 The economic status may be identified independently of, or applied in combination with, project maturity sub-classification to more completely describe the project. Economic status is not the only qualifier that allows defining Contingent or Prospective Resources sub-classes. Within Contingent Resources, applying the project status to decision gates (and/or incorporating them in a plan to execute) more appropriately defines whether the project is placed into the sub-class of either Development Pending versus On Hold, Not Viable, or Unclarified.

2.1.3.7.6 Where evaluations are incomplete and it is premature to clearly define the associated cash flows, it is acceptable to note that the project economic status is "undetermined."

2.2 Resources Categorization

2.2.0.1 The horizontal axis in the resources classification in Figure 1.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

A. The total petroleum remaining within the accumulation (in-place resources).

B. The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).

C. Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

2.2.0.2 The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3), 1C, 2C, 3C, C1, C2, and C3; or 1U, 2U, and 3U resources categories. The commercial chance of success is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

2.2.0.3 There must be a single set of defined conditions applied for resource categorization. Use of different commercial assumptions for categorizing quantities is referred to as "split conditions" and are not allowed. Frequently, an entity will conduct project evaluation sensitivities to understand potential implications when making project selection decisions. Such sensitivities may be fully aligned to resource categories or may use single parameters, groups of parameters, or variances in the defined conditions.

2.2.0.4 Moreover, a single project is uniquely assigned to a sub-class along with its uncertainty range. For example, a project cannot have quantities classified in both Contingent Resources and Reserves, for instance as 1C, 2P, and 3P. This is referred to as "split classification."

2.2.1 Range of Uncertainty

2.2.1.1 Uncertainty is inherent in a project's resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see Section 4.2, Resources Assessment Methods).

2.2.1.2 When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

A. There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

B. There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

C. There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

2.2.1.3 In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

2.2.1.4 When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section 2.2.2, Category Definitions and Guidelines).

2.2.1.5 Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

2.2.1.6 While there may be significant chance that sub-commercial and undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable quantities independent of such likelihood when considering what resources class to assign the project quantities.

2.2.2 Category Definitions and Guidelines

2.2.2.1 Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

2.2.2.2 Use of consistent terminology (Figures 1.1 and 2.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible (P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. Table 3 provides criteria for the Reserves categories determination.

2.2.2.3 For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

2.2.2.4 For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

2.2.2.5 Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see Section 4.2.1, Aggregating Resources Classes).

2.2.2.6 Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

2.2.2.7 All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Section 3.1, Assessment of Commerciality).

2.2.2.8 Tables 1, 2, and 3 present category definitions and provide guidelines designed to promote consistency in resources assessments. The following summarize the definitions for each Reserves category in terms of both the deterministic incremental method and the deterministic scenario method, and also provides the criteria if probabilistic methods are applied. For all methods (incremental, scenario, or probabilistic), low, best and high estimate technical forecasts are prepared at an effective date (unless justified otherwise), then tested to validate the commercial criteria, and truncated as applicable for determination of Reserves quantities.

A. **Proved Reserves** are those quantities of Petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under defined technical and commercial conditions. If deterministic methods are used, the term “reasonable certainty” is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

B. **Probable Reserves** are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

C. ***Possible Reserves*** are those additional Reserves that analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves that are located outside of the 2P area (not upside quantities to the 2P scenario) may exist only when the commercial and technical maturity criteria have been met (that incorporate the Possible development scope). Stand-alone Possible Reserves must reference a commercial 2P project (e.g., a lease adjacent to the commercial project that may be owned by a separate entity), otherwise stand-alone Possible is not permitted.

2.2.2.9 One, but not the sole, criterion for qualifying discovered resources and to categorize the project's range of its low/best/high or P90/P50/P10 estimates to either 1C/2C/3C or 1P/2P/3P is the distance away from known productive area(s) defined by the geoscience confidence in the subsurface.

2.2.2.10 A conservative (low-case) estimate may be required to support financing. However, for project justification, it is generally the best-estimate Reserves or Resources quantity that passes qualification because it is considered the most realistic assessment of a project's recoverable quantities. The best estimate is generally considered to represent the sum of Proved and Probable estimates (2P) for Reserves, or 2C when Contingent Resources are cited, when aggregating a field, multiple fields, or an entity's resources.

2.2.2.11 It should be noted that under the deterministic incremental method, discrete estimates are made for each category and should not be aggregated without due consideration of associated confidence. Results from the deterministic scenario, deterministic incremental, geostatistical and probabilistic methods applied to the same project should give comparable results (see Section 4.2, Resources Assessment Methods). If material differences exist between the results of different methods, the evaluator should be prepared to explain these differences.

2.3 Incremental Projects

2.3.0.1 The initial resources assessment is based on application of a defined initial development project, even extending into Prospective Resources. Incremental projects are designed to either increase recovery efficiency, reduce costs, or accelerate production through either maintenance of or changes to wells, completions, or facilities or through infill drilling or by means of improved recovery. Such projects are classified according to the resources classification framework (Figure 1.1), with preference for applying project maturity sub-classes (Figure 2.1). Related incremental quantities are similarly categorized on the range of uncertainty of recovery. The projected recovery change can be included in Reserves if the degree of commitment is such that the project has achieved commercial maturity (See Section 2.1.2, Determination of Commerciality). The quantity of such incremental recovery must be supported by technical evidence to justify the relative confidence in the resources category assigned.

2.3.0.2 An incremental project must have a defined development plan. A development plan may include projects targeting the entire field (or even multiple, linked fields), reservoirs, or single wells. Each incremental project will have its own planned timing for execution and resource quantities attributed to the project. Development plans may also include appraisal projects that will lead to subsequent project decisions based on appraisal outcomes.

2.3.0.3 Circumstances when development will be significantly delayed and where it is considered that Reserves are still justified should be clearly documented. If there is no longer the reasonable expectation of project execution (i.e., historical track record of execution, project progress), forecast project incremental recoveries are to be reclassified as Contingent Resources (see Section 2.1.2, Determination of Commerciality).

2.3.1 Workovers, Treatments, and Changes of Equipment

2.3.1.1 Incremental recovery associated with a future workover, treatment (including hydraulic fracturing stimulation), re-treatment, changes to existing equipment, or other mechanical procedures where such projects have routinely been successful in analogous reservoirs may be classified as Developed Reserves, Undeveloped Reserves, or Contingent Resources, depending on the associated costs required (see Section 2.1.3.2, Reserves Status) and the status of the project's commercial maturity elements.

2.3.1.2 Facilities that are either beyond their operational life, placed out of service, or removed from service cannot be associated with Reserves recognition. When required facilities become unavailable or out of service for longer than a year, it may be necessary to reclassify the Developed Reserves to either Undeveloped Reserves or Contingent Resources. A project that includes facility replacement or restoration of operational usefulness must be identified, commensurate with the resources classification.

2.3.2 Compression

2.3.2.1 Reduction in the backpressure through compression can increase the portion of in-place gas that can be commercially produced and thus included in resources estimates. If the eventual installation of compression meets commercial maturity requirements, the incremental recovery is included in either Undeveloped Reserves or Developed Reserves, depending on the investment on meeting the Developed or Undeveloped classification criteria. However, if the cost to implement compression is not significant, relative to the cost of one new well in the field, or there is reasonable expectation that compression will be implemented by a third party in a common sales line beyond the reference point, the incremental quantities may be classified as Developed Reserves. If compression facilities were not part of the original approved development plan and such costs are significant, it should be treated as a separate project subject to normal project maturity criteria.

2.3.3 Infill Drilling

2.3.3.1 Technical and commercial analyses may support drilling additional producing wells to reduce the well spacing of the initial development plan, subject to government regulations. Infill drilling may have the combined effect of increasing recovery and accelerating production. Only the incremental recovery (i.e. recovery from infill wells less the recovery difference in earlier wells) can be considered as additional Reserves for the project; this incremental recovery may need to be reallocated.

2.3.4 Improved Recovery

2.3.4.1 Improved recovery is the additional petroleum obtained, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural reservoir energy. It includes secondary recovery (e.g., waterflooding and pressure maintenance), tertiary recovery processes (thermal, miscible gas injection, chemical injection, and other types), and any other means of supplementing natural reservoir recovery processes.

2.3.4.2 Improved recovery projects must meet the same Reserves technical and commercial maturity criteria as primary recovery projects.

2.3.4.3 The judgment on commerciality is based on pilot project results within the subject reservoir or by comparison to a reservoir with analogous rock and fluid properties and where a similar established improved recovery project has been successfully applied.

2.3.4.4 Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed portion of the project, where the response provides support for the analysis on which the project is based. The improved recovery project’s resources will remain classified as Contingent Resources Development Pending until the pilot has demonstrated both technical and commercial feasibility and the full project passes the Justified for Development “decision gate.”

2.4 Unconventional Resources

2.4.0.1 The types of in-place petroleum resources defined as conventional and unconventional may require different evaluation approaches and/or extraction methods. However, the PRMS resources definitions, together with the classification system, apply to all types of petroleum accumulations regardless of the in-place characteristics, extraction method applied, or degree of processing required.

A. Conventional resources exist in porous and permeable rock with pressure equilibrium. The PIIP is trapped in discrete accumulations related to a local geological structure feature and/or stratigraphic condition. Each conventional accumulation is typically bounded by a down dip contact with an aquifer, as its position is controlled by hydrodynamic interactions between buoyancy of petroleum in water versus capillary force. The petroleum is recovered through wellbores and typically requires minimal processing before sale.

B. Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and are not significantly affected by hydrodynamic influences (also called "continuous-type deposit"). Usually there is not an obvious structural or stratigraphic trap. Examples include coalbed methane (CBM), basin-centered gas (low permeability), tight gas and tight oil (low permeability), gas hydrates, natural bitumen (very high viscosity oil), and oil shale (kerogen) deposits. Note that shale gas and shale oil are sub-types of tight gas and tight oil where the lithologies are predominantly shales or siltstones. These accumulations lack the porosity and permeability of conventional reservoirs required to flow without stimulation at economic rates. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, hydraulic fracturing stimulation for tight gas and tight oil, steam and/or solvents to mobilize natural bitumen for in-situ recovery, and in some cases, surface mining of oil sands). Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders).

2.4.0.2 For unconventional petroleum accumulations, reliance on continuous water contacts and pressure gradient analysis to interpret the extent of recoverable petroleum is not possible. Thus, there is typically a need for increased spatial sampling density to define uncertainty of in-place quantities, variations in reservoir and hydrocarbon quality, and to support design of specialized mining or in-situ extraction programs. In addition, unconventional resources typically require different evaluation techniques than conventional resources.

2.4.0.3 Extrapolation of reservoir presence or productivity beyond a control point within a resources accumulation must not be assumed unless there is technical evidence to support it. Therefore, extrapolation beyond the immediate vicinity of a control point should be limited unless there is clear engineering and/or geoscience evidence to show otherwise.

2.4.0.4 The extent of the discovery within a pervasive accumulation is based on the evaluator's reasonable confidence based on distances from existing experience, otherwise quantities remain as undiscovered. Where log and core data and nearby producing analogs provide evidence of potential economic viability, a successful well test may not be required to assign Contingent Resources. Pilot projects may be needed to define Reserves, which requires further evaluation of technical and commercial viability.

2.4.0.5 A fundamental characteristic of engagement in a repetitive task is that it may improve performance over time. Attempts to quantify this improvement gave rise to the concept of the manufacturing progress function commonly called the "learning curve." The learning curve is characterized by a decrease in time and/or costs, usually in the early stages of a project when processes are being optimized. At that time, each new improvement may be significant. As the project matures, further improvements in time or cost savings are typically less substantial. In oil and gas developments with high well counts and a continuous program of activity (multi-year), the use of a learning curve within a resources evaluation may be justified to predict improvements in either the time taken to carry out the activity, the cost to do so, or both. While each development project is unique, review of analogs can provide guidance on such predictions and the range of associated uncertainty in the resulting recoverable resources estimates (see also Section 3.1.2 Economic Criteria).