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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934** **FOR THE FISCAL YEAR ENDED December 31, 2024**
☐	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934** **FOR THE TRANSITION PERIOD OF _____ TO _____.**

Commission File Number: 001-41489

ENCORE ENERGY CORP.

(Exact name of registrant as specified in its charter)

British Columbia, Canada	**Not Applicable**
State or other jurisdiction of incorporation or organization	(I.R.S. Employer Identification No.)

101 N. Shoreline Blvd, Suite 450, Corpus Christi, TX 78401
(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code: **361-239-5449**
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Trading Symbol**	**Name of each exchange on which registered**
Common Shares, no par value	EU	The Nasdaq Stock Market LLC TSX Venture Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Exchange Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large, accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large, accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☒	**Accelerated filer**	☐	**Non-accelerated filer**	☐
		Smaller reporting company	☐	**Emerging growth company**	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes☐ No ☒

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter: $726.8 million.

As of February 25, 2025, there were 186,261,281 shares of the registrant's no par value common shares, the registrant's only outstanding class of voting securities, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Certain information required for Part III of this Annual report on Form 10-K is incorporated by reference to the registrant's definitive proxy statement for the 2025 Annual Meeting of Shareholders.

Auditor Firm Id:	185	Auditor Name:	KPMG LLP	Auditor Location:	Houston, Texas, United State

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`When we use the terms "enCore Energy Corp.," "we," "us," "our," or the "Company," we are referring to enCore Energy Corp. and its subsidiaries, unless the context otherwise requires. We have included technical terms important to an understanding of our business under "Glossary of Common Terms" at the end of this section. Throughout this document we make statements that are classified as "forward-looking." Please refer to the "Cautionary Statement Regarding Forward-Looking Statements" section of this document for an explanation of these types of assertions.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K ("Annual Report") and information incorporated by reference herein, contains forward-looking statements and forward-looking information within the meaning of the Private Securities Litigation Reform Act of 1995 and applicable Canadian securities legislation that are subject to risks and uncertainties. Forward-looking statements and information can generally be identified by the use of forward-looking terminology such as "may," "will," "expect," "intend," "estimate," "anticipate," "believe," "continue," "plans," "maintains," "projects," and similar terminology or variations (including negative variations) of such words and phrases or statements. Forward-looking statements and information are not historical facts, are made as of the date of this Annual Report, and include, but are not limited to, statements regarding discussions of results from operations (including, without limitation, statements about the Company's opportunities, strategies, competition, expected activities and expenditures, including its sales strategy providing a base level of projected income, as the Company pursues its business plan, the adequacy of the Company's available cash resources and other statements about future events or results), performance (both operational and financial), including operational expansion, the Company's belief it is positioned to meet the increased demand for clean, reliable nuclear energy, the Company's belief it can double its uranium extraction in 2025 from its extract results in 2024, the expected gross revenue sensitivity on contracted sales and the Company's 2025 strategic priorities) and business prospects, future business plans and opportunities and statements as to management's expectations with respect to, among other things, the activities contemplated in this Annual Report.

Forward-looking statements and information may include, but are not limited to, statements with respect to:

- the Company's future financial and operational performance;
- the sufficiency of the Company's current working capital, anticipated cash flow or its ability to raise necessary funds;
- the anticipated amount and timing of work programs;
- our expectations with respect to future exchange rates;
- the estimated cost of and availability of funding necessary for sustaining capital;
- forecast capital and non-operating spending, including changes in cost as a result of changes in trade restrictions, for example: the imposition of tariffs;
- the Company's plans and expectations for its property, exploration, development, extraction and community relations operations;
- the use of available funds;
- expectations regarding the process for and receipt of regulatory approvals, permits and licenses under governmental and other applicable regulatory regimes, including U.S. government policies towards domestic uranium supply;
- expectations about future uranium market prices, production costs and global uranium supply and demand;
- expectations regarding holding physical uranium for long-term investment;
- the establishment of mineral resources on any of the Company's current or future mineral properties (other than the Company's properties that currently have established mineral resource estimates);
- future royalty and tax payments and rates;
- expectations regarding possible impacts of litigation and regulatory actions; and
- the completion of reclamation activities at former mine or extraction sites.

Such forward-looking statements reflect the Company's current views with respect to future events, based on information currently available to the Company and are subject to and involve certain known and unknown risks, uncertainties, assumptions and other factors which may cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed in or implied by such forward-looking statements and information. The forward-looking statements and information in this Annual Report are based on material assumptions, including the following:

- our budget, including expected levels of exploration, evaluation, development, extraction and operational activities and costs, as well as assumptions regarding market conditions and other factors upon which we have based our income and expenditure expectations;
- assumptions regarding the timing and use of our cash resources;
- our ability to, and the means by which the Company can, raise additional capital to advance other exploration and evaluation objectives;
- our operations and key suppliers are essential services;
- our employees, contractors and subcontractors will be available to continue operations;
- our ability to obtain all necessary regulatory approvals, permits and licenses for our planned activities under governmental and other applicable regulatory regimes;
- our expectations regarding the demand for and supply of uranium, the outlook for long-term contracting, changes in regulations, public perception of nuclear power, and the construction of new and ongoing operation of existing nuclear power plants;
- our expectations regarding spot and long-term prices and realized prices for uranium;
- our expectations that our holdings of physical uranium will be helpful in securing project financing and/or in securing long- term uranium supply agreements in the future;
- our expectations regarding tax rates, currency exchange rates, and interest rates;
- our decommissioning and reclamation obligations and the status and ongoing maintenance of agreements with third parties with respect thereto;
- our mineral resource estimates, and the assumptions upon which they are based;
- our, and our contractors', ability to comply with current and future environmental, safety and other regulatory requirements and to obtain and maintain required regulatory approvals; and
- our operations are not significantly disrupted by political instability, nationalization, terrorism, sabotage, pandemics, social or political activism, breakdown, natural disasters, governmental or political actions, litigation or arbitration proceedings, equipment or infrastructure failure, labor shortages, transportation disruptions or accidents, or other development or exploration risks.

Some of the risks and uncertainties that could cause actual results to differ materially from any future results expressed in or implied by the forward-looking statements and information in this Annual Report include, among others, the following:

- our history of negative operating cash flows and our ability to develop or maintain positive cash flow from our mining activities;
- ability to obtain additional financing on acceptable terms when needed;
- we have experienced negative cash flows from operations and may need additional financing in connection with the implementation of our business and strategic plans from time to time;
- risks associated with our expansion-by-acquisition strategy;
- our properties do not contain Mineral Reserves and some of our properties, projects and facilities may not be economic within a reasonable time period or at all;
- reliance on key personnel, contractors and experts;
- conflicts of interest of our directors and officers;
- risks associated with exploration of, development of, and extraction from mineral properties;
- our reliance on third party drilling contractors, including an increased risk of loss, including weather related risks or underutilization of drilling rigs;
- risks inherent to mineral exploration and extraction;
- the commercial viability of economic extraction of minerals from uranium deposits;
- the subjectiveness and uncertainty of estimations of mineral resources;
- future mineral extraction estimates may not be achieved;
- estimates of commodity prices used in preliminary economic assessments may never be realized;
- requirements to obtain or retain key permits to advance or achieve extraction;
- involvement of Native American tribes in the permitting process;
- challenges to title of our mineral property interests;
- our ability to attract, retain, train, motivate, and develop skilled employees;
- existing competition and geopolitical changes in the competitive landscape;
- public opinion and perception of nuclear energy;
- volatility in market prices of uranium;
- applicable laws, regulations and standards, including environmental protection laws and regulations;
- our ability to raise equity or obtain debt financing;
- accuracy of extraction, capital and operating cost estimates;
- ability of novel mining methods for extraction to yield anticipated results;
- the need for technical innovation and risk of obsolescence;
- availability of a public market for Uranium, including global demand and supply;
- changes and uncertainty in U.S. trade policy, tariff and import/export regulations;
- risks related to our operations on federal lands, including possible designation of national monuments or withdrawal of permits;
- risks related to our Alta Mesa joint venture;
- taxation implications of U.S. holders because the Company is a passive foreign investment company;
- potential dilution if we issue additional common shares, no par value (the “common shares”) or securities convertible into common shares;
- price volatility of our common shares;
- our expectation to not declare or pay dividends;
- reliance on information technology systems, and cybersecurity risks;
- the time and resources necessary to comply with corporate governance practices and securities rules and regulations in the U.S. and Canada;
- our management’s ability to maintain effective internal controls;
- our remediation plan and ability to remediate the material weaknesses in our internal controls over financial reporting;
- potential lack of access to enforcement of civil liabilities against the Company or its directors and officers;
- our ability to protect our proprietary data, technology and intellectual property;
- changes in climate conditions; and
- other risks included under the heading “Risk Factors” in this Annual Report.

While forward-looking statements and information reflect our good faith beliefs, they are not guarantees of future performance. Any forward-looking statements and information are based on estimates and assumptions only as of the date of this Annual Report, and the Company undertakes no obligation to update or revise any forward-looking statement or information to reflect information, events, results, circumstances or the occurrence of unanticipated events, except as required by applicable laws. New factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factors on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements or information.

CAUTIONARY NOTE TO U.S. RESIDENTS CONCERNING DISCLOSURE OF MINERAL RESOURCES

Effective as of January 1, 2025, the Company no longer qualifies as a foreign private issuer as defined in Rule 405 under the Securities Act of 1933, as amended (the "Securities Act") and Rule 3b-4 under the Securities Exchange Act of 1934, as amended (the "Exchange Act") and therefore has become a domestic issuer required to file this Annual Report pursuant to Sections 13 or 15(d) of the Exchange Act and to report its financial results under United States generally accepted accounting principles ("U.S. GAAP").

All mineral estimates constituting mining operations that are material to our business or financial condition included in this Annual Report, and in the documents incorporated by reference herein, have been prepared in accordance with subpart 1300 of Regulation S-K (collectively, "S-K 1300") and are supported by initial assessments prepared in accordance with the requirements of S-K 1300. S-K 1300 provides for the disclosure of: (i) "Inferred Mineral Resources," which investors should understand have the lowest level of geological confidence of all Mineral Resources and thus may not be considered when assessing the economic viability of a mining project and may not be converted to a Mineral Reserve (as defined below); (ii) "Indicated Mineral Resources," which investors should understand have a lower level of confidence than that of a "Measured Mineral Resource" and thus may be converted only to a "Probable Mineral Reserve," and (iii) Measured Mineral Resources, which investors should understand have sufficient geological certainty to be converted to a "Proven Mineral Reserve" or to a "Probable Mineral Reserve." **Investors are cautioned not to assume that all or any part of Measured Mineral Resources or Indicated Mineral Resources will ever be converted into Mineral Reserves as defined by S-K 1300. Investors are cautioned not to assume that all or any part of an Inferred Mineral Resource exists or is economically or legally mineable, or that an Inferred Mineral Resource will ever be upgraded to a higher category.**

GLOSSARY OF TERMS

For ease of reference, the following factors for converting metric measurements into imperial equivalents are as follows:

Metric Units	Multiply By	Imperial Units
Hectares	2.471	= acres
Meters	3.281	= feet
Kilometers	0.621	= miles (5,280 feet)
Grams	0.032	= ounces (troy)
Tonnes	1.102	= tons (short) (2,000 lbs)
grams/tonne	0.029	= ounces (troy)/ton

Abbreviations

In this Annual Report, the abbreviations set forth below have the following meanings:

$	U.S. Dollar	km^2	square kilometer
°	degrees	kv	kilovolt
%	percent	m	meter
C$	Canadian Dollar	m^2	square meter
ft	feet	lb	pound
g/t	metric gram per metric tonne	U_3O_8	tri-Uranium octo-oxide
kg	kilogram	ppm	parts per million
kg/t	kilograms per tonne	U	Uranium
kl/t	kiloliters per tonne	ac	acres

In this Annual Report, the following terms have the meanings set forth herein:

"**Alta Mesa**" **or** "**Alta Mesa Project**" means the Alta Mesa Uranium Central Processing Plant and Wellfield located in Brooks County, Texas, USA.

"Alta Mesa Technical Report(s)" means the S-K 1300 technical report summary entitled "Alta Mesa Uranium Project, Brooks County, Texas, USA, S-K 1300 Technical Report Summary" and "Alta Mesa Uranium Project, Brooks County, Texas, USA, National Instrument 43-101, Technical Report" dated February 19, 2025 and effective December 31, 2024 prepared by Stuart Bryan Soliz, PG of SOLA Project Services, LLC.

"**BLM**" means the U.S. Bureau of Land Management.

"Boss" means Boss Energy, Ltd. the partner with the Company in JV Alta Mesa LLC, that is 70% owned by the Company and 30% owned by Boss. The Company is the Manager of JV Alta Mesa LLC. Boss is a public company traded on the ASX in Australia.

"**Central Processing Plant**" or "**CPP**" means the central operational facilities Uranium processing occurs following Uranium extraction from the ore body using ISR.

"**Dewey Burdock**" **or** "**Dewey Burdock Project**" means the Dewey Burdock Uranium Project located in Custer and Fall River Counties, South Dakota, USA.

"**Dewey Burdock Technical Report(s)**" means the S-K 1300 technical report entitled "Dewey Burdock Project, South Dakota, USA, S-K 1300 Technical Report Summary" and "Dewey Burdock Project South Dakota, USA, National Instrument 43-101, Preliminary Economic Assessment Technical Report" dated January 6, 2025, and effective as of October 8, 2024 prepared by Stuart Bryan Soliz, PG of SOLA Project Services, LLC.

"EPA" means the U.S. Environmental Protection Agency.

"**Exploration Stage Issuer**" is an issuer that has no material property with Mineral Reserves disclosed.

"**Exploration Stage Property**" is a property that has no Mineral Reserves disclosed.

"**Gas Hills**" **or** "**Gas Hills Project**" means the Gas Hills Uranium Project, located in Fremont and Natrona Counties, Wyoming, USA.

"**Gas Hills Technical Report**" means the S-K 1300 technical report entitled "Technical Report Preliminary Economic Assessment Gas Hills Uranium Project. Fremont and Natrona Counties," dated February 4, 2025 and effective December 31, 2024, prepared by Chris McDowell, P.G. and Ray Moores, P.E. of Western Water Consultants d/b/a WWC Engineering.

"**GT**" means grade-thickness, a measure referring to the concentration of a mineral in Ore and the width of the Ore body.

"Inferred Mineral Resource" is a component of Mineral Resource for which quantity and grade or quality are estimated on the basis of limited geological evidence and sampling; where the term limited geological evidence means evidence that is only sufficient to establish that geological and grade or quality continuity is more likely than not. The level of geological uncertainty associated with an Inferred Mineral Resource is too high to apply relevant technical and economic factors likely to influence the prospects of economic extraction in a manner useful for evaluation of economic viability. Because an Inferred Mineral Resource has the lowest level of geological confidence of all Mineral Resources, which prevents the application of the modifying factors in a manner useful for evaluation of economic viability, an Inferred Mineral Resource may not be considered when assessing the economic viability of a mining project and may not be converted to a Mineral Reserve.

"Indicated Mineral Resource" is that part of a Mineral Resource for which quantity and grade or quality are estimated on the basis of adequate geological evidence and sampling. The level of geological certainty associated with an Indicated Mineral Resource is sufficient to allow a qualified person to apply modifying factors in sufficient detail to support mine planning and evaluation of the economic viability of the deposit. Because an Indicated Mineral Resource has a lower level of confidence than the level of confidence of a Measured Mineral Resource, an Indicated Mineral Resource may only be converted to a Probable Mineral Reserve.

"**Initial Assessment**" is a preliminary technical and economic study of the economic potential of all or parts of mineralization to support the disclosure of Mineral Resources. The Initial Assessment must be prepared by a qualified person and must include appropriate assessments of reasonably assumed technical and economic factors, together with any other relevant operational factors, that are necessary to demonstrate at the time of reporting that there are reasonable prospects for economic extraction. An Initial Assessment is required for disclosure of Mineral Resources but cannot be used as the basis for disclosure of Mineral Reserves.

"**Ion-exchange**" or "**IX**" means a reversible chemical reaction that swaps ions between a solid and a solution. In the case of the Company's operation, the ion exchange occurs in a bed of strong base anionic polystyrene resin beads contained in a vessel or column.

"ISR" means In Situ Recovery (literally, 'in place' recovery) describes rocks or formations that have not been moved from their original position (also known as in situ leach or ISL).

"Measured Mineral Resource" is that part of a Mineral Resource for which quantity and grade or quality are estimated on the basis of conclusive geological evidence and sampling. The level of geological certainty associated with a Measured Mineral Resource is sufficient to allow a qualified person to apply modifying factors, as defined in this section, in sufficient detail to support detailed mine planning and final evaluation of the economic viability of the deposit. Because a Measured Mineral Resource has a higher level of confidence than the level of confidence of either an Indicated Mineral Resource or an Inferred Mineral Resource, a Measured Mineral Resource may be converted to a Proven Mineral Reserve or to a Probable Mineral Reserve.

"**Mesteña Grande**" **or** "**Mesteña Grande Project**" means the Mesteña Grande Uranium Project located in Brooks and Jim Hogg Counties, Texas, USA.

"Mesteña Grande Technical Report(s)" means the S-K 1300 technical report summary entitled "Mesteña Grande Uranium Project, Brooks and Jim Hogg Counties, Texas, USA, S-K 1300 Technical Report Summary, Initial Assessment" and "Mesteña Grande Uranium Project, Brooks and Jim Hogg Counties, Texas, USA, National Instrument 43-101, Preliminary Economic Assessment," dated February 19, 2025 and effective December 31, 2024 prepared by Stuart Bryan Soliz, PG of SOLA Project Services.

"**Mineral Reserve**" is an estimate of tonnage and grade or quality of Indicated and Measured Mineral Resources that, in the opinion of the qualified person, can be the basis of an economically viable project. More specifically, it is the economically mineable part of a Measured or Indicated Mineral Resource, which includes diluting materials and allowances for losses that may occur when the material is mined or extracted.

"**Mineral Resource**" is a concentration or occurrence of solid material of economic interest in or on the Earth's crust in such form, grade or quality and quantity that there are reasonable prospects for economic extraction. A Mineral Resource is a reasonable estimate of mineralization, taking into account relevant factors such as cut-off grade, likely mining dimensions, location or continuity, that, with the assumed and justifiable technical and economic conditions, is likely to, in whole or in part, become economically extractable. It is not merely an inventory of all mineralization drilled or sampled.

"**Mineralization**" means, in exploration, a reference to a notable concentration of metals and their associated mineral compounds, or a specific mineral, within a body of rock.

"**Modifying Factors"** are the factors that a qualified person must apply to Indicated and Measured Mineral Resources and then evaluate in order to establish the economic viability of Mineral Reserves. A qualified person must apply and evaluate modifying factors to convert Measured and Indicated Mineral Resources to Proven and Probable Mineral Reserves. These factors include but are not restricted to: mining; processing; metallurgical; infrastructure; economic; marketing; legal; environmental compliance; plans, negotiations, or agreements with local individuals or groups; and governmental factors. The number, type and specific characteristics of the modifying factors applied will necessarily be a function of and depend upon the mineral, mine, property, or project.

"**NRC**" means US Nuclear Regulatory Commission.

"**Ore**" means a natural aggregate of one or more minerals which may be mined and sold at a profit, or from which some part may be profitably separated. A company may only refer to Mineral Reserves (as that term is defined in S-K 1300) as "ore."

"**Probable Mineral Reserve"** is the economically mineable part of an Indicated Mineral Resource, and in some circumstances, a Measured Mineral Resource. The confidence in the Modifying Factors applying to a Probable Mineral Reserve is lower than that applying to a Proven Mineral Reserve.

"**Proven Mineral Reserve**" is the economically mineable part of a Measured Mineral Resource. A Proven Mineral Reserve implies a high degree of confidence in the Modifying Factors.

"PFN" is a modern geologic wireline logging method known as Prompt Fission Neutron. PFN is considered a direct measurement of true uranium concentration (% U) and is used to verify the in-situ grades of mineral intercepts previously reported by gamma logging. PFN logging is accomplished by a down-hole probe in much the same manner as standard gamma logs, only, in the case of PFN logging, only the mineralized interval is logged.

"**Qualified Person**" or "QP" means an individual who:

a. is an engineer or geoscientist with a university degree, or equivalent accreditation, in an area of geoscience, or engineering, relating to mineral exploration or mining;
b. has at least five years of experience in mineral exploration, mine development or operation or mineral project assessment, or any combination of these, that is relevant to his or her professional degree or area of practice;
c. has experience relevant to the subject matter of the mineral project and the technical report;
d. is in good standing with a professional association;
e. in the case of a professional association in a foreign jurisdiction, has a membership designation that requires attainment of a position of responsibility in their profession that requires the exercise of independent judgment; and requires:
    - favorable confidential peer evaluation of the individual's character, professional judgement, experience, and ethical fitness; or

- a recommendation for membership by at least two peers and demonstrated prominence or expertise in the field of mineral exploration or mining.

"RML" means Radioactive Material License and is a legal authorization issued by a government regulatory agency that allows an individual, business, or institution to possess, use, store, or dispose of radioactive materials.

"**Rosita**" **or** "**Rosita Project**" means the Rosita Uranium Project located in Duval County, Texas, USA.

"**SEDAR**" means SEDAR+, the System for Electronic Document Analysis and Retrieval.

"**South Texas Integrated ISR Project**" or "**STX Integrated**" is comprised of the Rosita CPP located in Duval County, Texas on a 200-acre tract of land owned by the Company, and multiple associated Satellite IX facilities at various project sites across South Texas and associated wellfields.

"South Texas Uranium Project Technical Report" means the S-K 1300 technical report entitled "Technical Report on the South Texas Integrated Uranium Projects, Texas, USA," dated February 15, 2025, and effective December 31, 2024, prepared by Chris McDowell, P.G. and Ray Moores, P.E. of Western Water Consultants d/b/a WWC Engineering.

"TCEQ" means the Texas Commission on Environmental Quality.

"TRC" means the Texas Railroad Commission.

"Uranium" means naturally radioactive, heavy, metallic element of atomic number 92. Uranium in its pure form is a heavy metal. Its two principal isotopes are U-238 and U-235, of which U-235 is the necessary component for the nuclear fuel cycle. However, "uranium" used in this annual report refers to triuranium octoxide, also called "U_3O_8," and is produced from uranium deposits. It is the most actively traded uranium-related commodity. Our operations extract and ship "yellowcake" which typically contains 70% to 90% U_3O_8 by weight.

"**USGS**" means United States Geological Survey.

"U_3O_8" a standard chemical formula commonly used to express the natural form of uranium mineralization. U represents uranium and O represents oxygen. U_3O_8 is contained in "yellowcake" or "uranium concentrate" accounting for 70% to 90% by weight.

"WDEQ" means Wyoming Department of Environmental Quality.

Part I

Item 1. Business and Properties

Our Company

enCore Energy Corp., America's Clean Energy Company™, was incorporated on October 30, 2009, under the Laws of British Columbia and is a reporting issuer in all of the provinces and territories of Canada. As of January 1, 2025, the Company ceased to be a "foreign private issuer" and has become a "domestic issuer" and a large accelerated filer within the meanings under the Exchange Act. As a result, the Company must comply with the filing deadlines and disclosure obligations of a domestic issuer and large accelerated filer as set forth in the Exchange Act. This classification impacts the timing of our periodic filings, internal control assessments, and other regulatory requirements. The Company's common shares are listed on The Nasdaq Capital Market and the TSX Venture Exchange ("TSX-V") under the trading symbol EU.

As of December 31, 2024, the Company is an "Exploration Stage Issuer" as defined by S-K 1300, and as required by the SEC to be defined as a Development Stage Issuer as it has not established proven or probable Mineral Reserves, through the completion of a pre-feasibility or feasibility study for any of our uranium projects. Even though we commenced extraction of uranium at our Rosita Uranium Project and our Alta Mesa Uranium Project, the Company remains classified as an Exploration Stage Issuer and will continue to remain an Exploration Stage Issuer until such time as Proven or Probable Mineral Reserves have been established at one of our uranium projects.

The Company is focused on extracting domestic uranium within the United States. The Company only utilizes the proven ISR technology to provide necessary fuel for the generation of clean, reliable, and carbon-free nuclear energy. In 2024, the Company commenced uranium extraction at the Rosita CPP in South Texas, becoming one of only three uranium extraction operations in the United States and the first in Texas in 10 years. In June 2024, the Company commenced uranium extraction at the Alta Mesa CPP in South Texas. enCore's strategy is to build uranium extraction capacity by developing and placing into operation a series of uranium extraction facilities in South Texas, followed by a future pipeline of exploration projects in South Dakota and Wyoming, becoming a leading supplier of domestic uranium to fuel a growing demand for clean energy generation using nuclear power.

In 2024, the Company set forth to execute five main objectives. The Company believes the execution of these objectives has and will continue to position enCore to quickly respond to the ever-changing global factors, achieve strategic expansions, and build on its adaptability while strengthening the Company's financial health. These objectives are as follow:

Commenced and Expanded Uranium Extraction at the Alta Mesa Project

Utilizing extraction-ready CPP in South Texas, the Company has implemented a strategy that it anticipates will continue to build value and phased growth. In the second quarter of 2024, the Company commenced uranium extraction operations at its Alta Mesa CPP, and as a result, became one of only a handful of companies in the world with more than one operational uranium extraction operation. In 2025, through the expansion of CPP and wellfield capacity, the Company believes it can double the uranium extraction over the 2024 extraction results. The Company is focused on a long-term strategy of being a supplier of choice for a nuclear industry that is experiencing sustainable growth for the first time in over 45 years.

Streamlined Operations and Rationalized Asset Base

Successful execution is critical, especially in an industry where talent and timing are essential to our success. Adapting swiftly to favorable market conditions is a priority for us. In December 2023, we announced the sale of 30% of the Alta Mesa Project to Boss in the form of a Joint Venture for $60 million. Additionally, Boss invested directly in the Company an additional $10 million. The Company intends to continue to rationalize its asset base through the execution of our non-core asset divestment strategy strengthening our financial position and increasing financial resources in a non-dilutive way. We have demonstrated the ability to derive substantial value for our shareholders from our non-core assets by using different approaches to divestment. The Company currently holds several non-core conventional projects available for acquisition. Lastly, the Company continues to optimize operations to improve extraction results and manage costs effectively.

M*ergers and Acquisitions*

Since December 2020, we have demonstrated, through four significant transactions, our intent is to drive growth and provide value for our shareholders through select, accretive merger and acquisition (M&A) activity that complement its own organic growth.

Contract and Sales Strategy Formalization

The Company will continue to leverage its strong baseload contracting strategy and industry reputation as a reliable multi-facility domestic supplier to ensure that our operating assets are able to create revenue regardless of market conditions. As the Company increases uranium extraction from its South Texas facilities, we expect to grow our contract portfolio through the addition of new contracts. The Company will continue to focus on adding new multi-year, hybrid, market-based contracts to maximize profits while protecting against price declines. The Company believes this strategy should provide robust returns on uranium extraction while ensuring a base level of income to support continued operations during market declines over the next decade.

Established Fiscally Responsible Management and Strong Governance for the Benefit of Shareholders

On October 24, 2024, the Company announced that it completed its inaugural greenhouse gas ("GHG") emissions and sustainability report to meet the needs of institutional clients and utility customers (the "Sustainability Report"). The Company will continue to strengthen and grow its management and operations teams by offering competitive employment opportunities and benefits package. The Company has established continuous improvement systems in its organization to ensure proper governance of the company, its operations, and its employees. Finally, the Company works to ensure its costs are as low as practicable while maintaining its ability to leverage its assets to provide value to shareholders. The Company assesses supply chain risks to ensure its ability to obtain critical components necessary to sustain its strategy.

About In-Situ Recovery (ISR), Technology

ISR is a minimally invasive, environmentally friendly, and economically competitive way of extracting minerals from the ground. It has proven to be a successful method of extracting uranium, and due to its cost efficiency, is economically viable to extract lower grade uranium deposits that might not justify the cost of conventional open pit or underground mining. In addition to significantly lower capital and operating costs, ISR operates without the open pits, waste dumps, or tailings associated with conventional mining and milling. These factors result in uranium extraction that is more environmentally responsible in a faster, more cost-efficient permitting, development and remediation process. ISR extracts uranium from the ground with minimal surface impact. When reclamation is completed, the surface is returned to its original state and use.

ISR is highly regulated in the United States. While some ISR operations in other jurisdictions use harsh chemicals such as sulfuric acid to remove uranium from the ore body, enCore only uses a lixiviant comprised of just oxygen and sodium bicarbonate (common baking soda) in the native groundwater to extract uranium at a near neutral pH with significantly less environmental impacts.

ISR usually takes place in sandstone deposits within a portion of the aquifer that the government has already exempted from protection as an underground source of drinking water due to its mineral content such as uranium, radium, and other minerals. An ISR wellfield is developed using a series of production patterns comprised of a series of injection and recovery wells. Injection wells introduce the lixiviant described above to the uranium bearing sandstone. As the lixiviant is injected through the uranium-bearing sandstone, the uranium is solubilized by the oxygen in the lixiviant, and the uranium-bearing lixiviant is carried through the sandstone to the recovery well. Recovery wells, equipped with submersible pumps, recover the uranium-bearing lixiviant out of the sandstone and lift it to the surface. The uranium-bearing lixiviant is then pumped into a surface collection system to be transferred to the ion exchange (IX) system. Surrounding the production patterns is a network of monitor wells used to observe groundwater chemistry and hydrology to assure there are no impacts to adjacent underground sources of drinking water. The combination of the production patterns and the monitor well network constitute what is called a wellfield.

After the uranium-bearing lixiviant reaches the IX system, it flows through a bed of IX resin where the uranium is removed from the lixiviant and loaded onto IX resin beads. This process is very similar to how a water softener works. The barren lixiviant is returned to the wellfield, where it is refortified with oxygen and sodium bicarbonate and reinjected into the uranium-bearing sandstone. A small portion, approximately 1% of the total volume, of the barren lixiviant is held back from reinjection. This is called a "process bleed," and it is intended to create a hydraulic sink in the wellfield to contain lixiviant within production patterns.

When the IX resin loads to capacity with uranium it is regenerated, using a salt solution rich in sodium bicarbonate, in the exact same manner as done for a water softener. This process is called “elution.” Elution produces a uranium-rich eluant that is transferred from the ion exchange system to the precipitation system. Using a series of additions of hydrogen peroxide, acid, and sodium hydroxide, the uranium is precipitated from the eluant and a uranium, “yellowcake,” slurry is created. It is then filtered and washed in a filter press and transferred to the drying system. Drying systems at the Company’s processing facilities use a low-temperature, zero emission, rotary vacuum drying system, the same equipment used for producing pharmaceuticals. Once dried the yellowcake is packaged into 55-gallon drums that are grouped into shipping lots. Each shipping lot is then transported to a North American conversion facility where it is weighed, sampled, and inventoried. This is the point at which the Company sells its product to its customers.

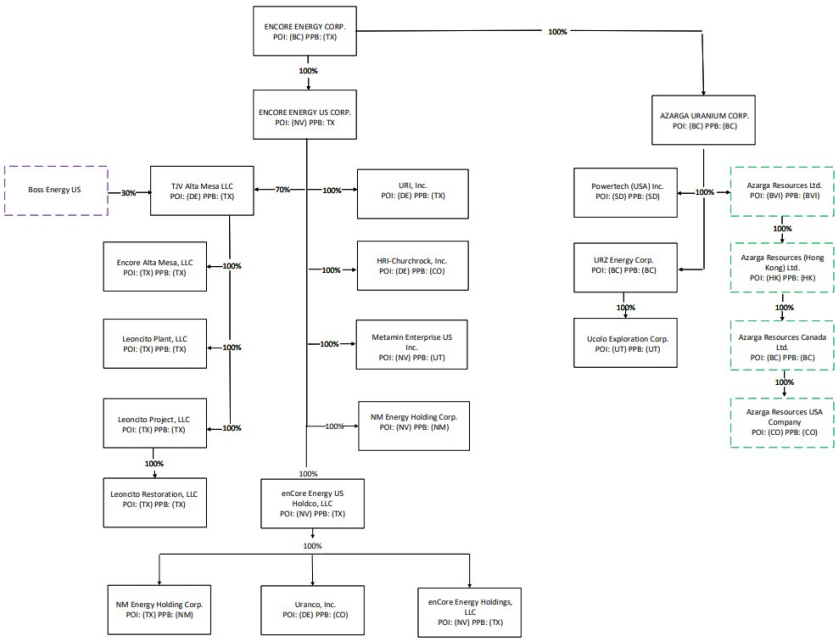
When the uranium orebody within an ISR wellfield is depleted, the Company is required to clean up the groundwater. The process of extracting uranium from the orebodies using our lixiviant does change the groundwater chemistry within the production patterns. After production is complete, the groundwater quality is restored to a quality consistent with the chemistry prior to the start of injection using reverse osmosis technology to clean it. This process does increase the amount of water that is consumed during wellfield operations, but in an average ISR wellfield, approximately 95% of the groundwater is preserved and retained at the end of the full production and restoration cycle. Once the government approves the groundwater restoration work, the injection, recovery and monitor wells are plugged and abandoned and the surface infrastructure is removed. The site is then surveyed for residual contamination that may need to be removed and the wellfield is returned to its prior use. At this point, the land and groundwater are once again suitable for all the same uses as prior to mining efforts.

The use of ISR technology in the US has a documented strong environmental record. Several wellfields have been restored and released, with the former wellfields now indistinguishable from the adjacent unimpacted land. The US government, in several public documents, has concluded that there have been no impacts to underground sources of drinking water by ISR uranium extraction or restoration.

Corporate Information

enCore was incorporated on October 30, 2009, under the Business Corporations Act (British Columbia) (the “BCBCA”) under the name “Dauntless Capital Corp.” The Company’s name was changed to “Tigris Uranium Corp.” on September 2, 2010, and changed to “Wolfpack Gold Corp.” on May 15, 2013. On August 15, 2014, the Company’s name was changed to “enCore Energy Corp.”

The following organizational chart illustrates enCore's principal subsidiaries as at the date of this Annual Report.



Notes:

* POI = Place of incorporation or legal organization
* PPB= Principal place of business
* Green = Expected to be dissolved
* Purple = Joint Venture with Boss

The principal offices of the Company are located at Suite 450, 101 N. Shoreline Blvd, Corpus Christi, Texas 78401. The Company's registered and records office is located at Suite 1200, 750 West Pender Street, Vancouver, British Columbia, V6C 2T8.

Competition

The uranium industry is highly competitive, and our competition includes larger, more established companies with longer operating histories that not only explore for and produce uranium but also market uranium and other products on a regional, national or worldwide basis. Due to their greater financial and technical resources, we may not be able to acquire additional uranium projects in a competitive bidding process involving such companies. Additionally, these larger companies have greater resources to continue with their operations during periods of depressed market conditions.

Geopolitical uncertainty

Geopolitical uncertainty driven by the Russian invasion of Ukraine has led many governments and utility providers to re-examine supply chains and procurement strategies reliant on nuclear fuel supplies coming out of, or through, Russia.

Sanctions, restrictions, and an inability to obtain insurance on cargo have contributed to transportation and other supply chain disruptions between producers and suppliers. As a result of this and coupled with multiple years of declining uranium production globally, uranium market fundamentals are shifting from an inventory driven market to one more driven by production. The Prohibiting Russian Uranium Imports Act (H.R. 1042) which was signed into law in May 2024, prohibits the importation of unirradiated, low-enriched uranium projected in the Russian Federation or by a Russian entity, with temporary waivers until January 1, 2028 in certain circumstances, after which the ban will be in effect until December 31, 2040.

Employees and Human Capital

As of December 31, 2024, 131 people were employed on a full-time basis and approximately 65 individuals provided services on a contractual basis, principally through our drilling rig contractors, all of whom were located in the U.S. Our Company is committed to attracting and retaining talented and experienced individuals to manage and support our operations. We engage in a variety of learning and development opportunities with our employees, including ongoing training, continuing education courses, workshops and seminars and membership in professional organizations relating to employees' areas of expertise. We strive to fill employment openings through internal promotions or transfers of qualified employees, as appropriate.

Available Information

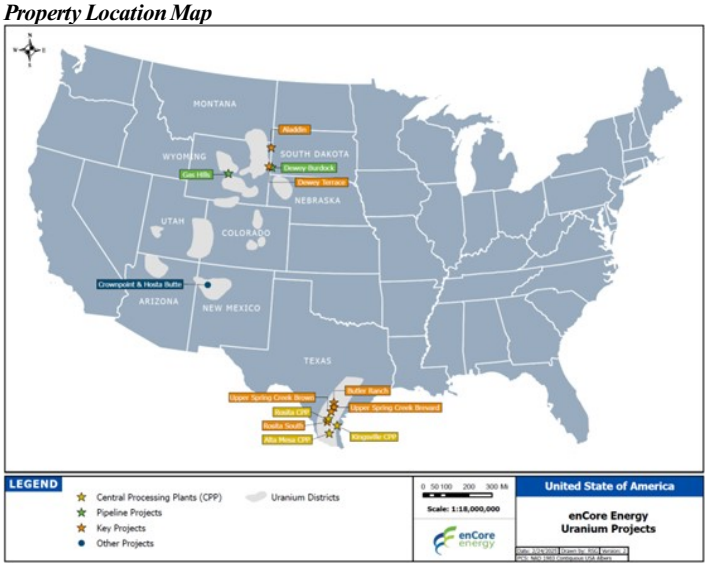
The Company's website address is www.encoreuranium.com and the Company's filings with the SEC, including our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to such reports, are available free of charge on our website as soon as reasonably practicable after such materials are filed or furnished electronically with the SEC. Additional information about the Company can be found on our website, however, such information is neither incorporated by reference nor included as part of this or any other report or information filed with or furnished to the SEC.

The SEC maintains an internet site (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC. Canadian securities authorities also maintain an internet site (www.sedarplus.ca) that contains reports, circulars, annual information statements and other information regarding the Company.

Our Mineral Properties

enCore controls key mineral properties within the United States, in Texas, South Dakota, Wyoming and New Mexico. enCore owns three of the current 11 licensed and constructed ISR CPPs in the United States[1], with all existing facilities located in the business-friendly, energy-centric state of Texas. Our plants' operations are designed and permitted to process uranium from a mix of satellite plants and primary sources within south Texas.

Property Location Map



Summary of Properties

South Texas Integrated ISR Project (Rosita CPP)

The South Texas Integrated ISR Project is an Exploration Stage Property which consists of five project areas: the Rosita Central Processing Plant (Rosita CPP), Butler Ranch Uranium ISR Project (Butler Ranch), Upper Spring Creek - Brevard Area ISR Uranium Project (USC – Brevard or Brevard), Upper Spring Creek - Brown Area ISR Uranium Project (USC – Brown or Brown), and Rosita South Cadena ISR Project (RS – Cadena or Cadena).

The Rosita CPP is a licensed ISR production facility with a capacity of 800,000 pounds of U_3O_8 per year. The Rosita CPP is located in Duval County about 14 miles southeast of the town of Freer and 60 miles west-northwest of the city of Corpus Christi on a 200-acre tract owned by the Company.

Alta Mesa Uranium Project, Texas

The Alta Mesa Uranium Project is an Exploration Stage Property and is a fully licensed and constructed ISR project and central processing facility, located on over 4,597 acres of private land in the state of Texas. Total operating capacity is 1.5 million lbs U_3O_8 per year of IX processing capacity, and further, the CPP has 2.0 million lbs per year of IX elution, uranium precipitation, drying and packaging capacity.

Mesteña Grande Uranium Project, Texas

The Mesteña Grande Uranium Project is an Exploration Stage Property that is located in Brooks and Jim Hogg Counties, Texas and is on land located adjacent to, and to the south, north, and west of the Alta Mesa Uranium Project. The property contains significant inferred mineral resources over approximately 195,717 acres of private land. It covers an approximate area of 35 miles in a north-south direction by 30 miles in an east-west direction.

Dewey Burdock Project, South Dakota

The Dewey Burdock Project is an Exploration Stage Property located in southwest South Dakota and is part of the northwestern extension of the Edgemont Uranium Mining District. The Dewey Burdock Project includes federal claims, private mineral rights and private surface rights controlling the entire area within the licensed project permit boundary as well as surrounding areas. The Company currently controls approximately 16,962 acres of net mineral rights and 12,613 acres of surface rights.

Gas Hills Project, Wyoming

The Gas Hills Project is an Exploration Stage Property located in Wyoming. The Company owns a 100% interest in the Gas Hills Exploration Project located in the historic Gas Hills Uranium District 45 miles east of Riverton, Wyoming. The Project consists of approximately 1,280 surface acres and 12,960 net mineral acres of unpatented lode mining claims, a State of Wyoming mineral lease, and private mineral leases, within a brownfield site which has experienced extensive development including mine and mill site production.

Other Non-Material Properties

The Company holds a number of other Exploration Stage Properties that the Company has determined are not material to its business, including the following properties which total in the aggregate approximately 360,000 acres of mineral claims, mineral leases, and fee minerals:

- *Nose Rock, New Mexico*. The Nose Rock project is located in McKinley County New Mexico on the northern edge of the Grants Uranium District.
- *Metamin Properties, Arizona, Utah and Wyoming*. Through its subsidiary Metamin Enterprises US Inc. (“MEUS”), the Company holds various prospective uranium mining properties located in the States of Arizona, Utah and Wyoming.
- *West Largo, New Mexico*. The West Largo project consist of approximately 3,840 acres (i.e. six square miles) in McKinley County, New Mexico.
- *Ambrosia Lake-Treeline, New Mexico*. The Ambrosia Lake – Treeline Property consists of deeded mineral rights totaling 24,555 acres and a mining lease along with certain unpatented mining claims covering approximately 1,700 acres.
- *Checkerboard Mineral Rights,* New Mexico. The land position covers approximately 300,000 acres of deeded ‘checkerboard’ mineral rights, also known as the Frisco and Santa Fe railroad grants.
- *Kingsville Dome, Texas.* The Kingsville Dome property is located in Kleberg County and is situated on several tracts of land leased from third parties. The property is situated approximately eight miles southeast of the city of Kingsville. The project is comprised of numerous mineral leases from private landowners, covering an area of approximately 2,434 gross and 2,227 net acres of mineral rights. The Kingsville Dome CPP is a licensed ISR production facility located on 15 acres of Company-owned property.
- *Vasquez Project, Texas.* The Vasquez project is located in Duval County. The Vasquez property consists of a mineral lease on 1,023 gross and net acres.
- *Dewey Terrace Project, Wyoming.* This project consists of approximately 1,874 acres of surface rights and approximately 7,514 acres of net mineral rights. The Dewey Terrace Project is located adjacent to the Dewey Burdock Project.
- *Juniper Ridge Project, Wyoming*. The Juniper Ridge project in Carbon County consists of approximately 640 surface acres and 3,240 net mineral acres of unpatented lode mining claims and a State of Wyoming mineral lease and is located within a brownfield site which has experienced extensive exploration, development, and mine production.
- *Centennial Project, Colorado.* The Centennial Project in Weld County is comprised of approximately 523.21 acres of surface rights and 237.09 acres of net mineral rights. Approximately 5,760 acres of minerals rights were conveyed back to Anadarko by Special Warranty Deed on January 2025, this conveyance significantly reduced the

project size. The Company intends to allow current leases to expire, and maintain existing mineral rights currently owned by the Company in fee.

- *Aladdin Project, Wyoming.* The Aladdin Project is comprised of private leases that cover approximately 5,166 acres of surface rights and 4,712 acres of net mineral rights. The Aladdin Project is 80 miles northwest of the Dewey Burdock Project.

- *Other Properties:* The Company holds the Shirley Basin Project in Wyoming the JB Project in Colorado and Utah, and the Ticaboo project in Utah.

Summary of Mineral Resources

The following table shows the Company's estimate of Mineral Resources as defined in S-K 1300 as of December 31, 2024.

Project	Measured Mineral Resources			Indicated Mineral Resources			Measured + Indicated			Inferred Mineral Resources		
	Tons (000s)	Grade (% eU3O8)	Pounds (000s eU3O8)	Tons (000s)	Grade (% eU3O8)	Pounds (000s eU3O8)	Tons (000s)	Grade (% eU3O8)	Pounds (000s eU3O8)	Tons (000s)	Grade (% eU3O8)	Pounds (000s eU3O8)
ISR Properties												
Region: Texas												
South Texas Integrated ISR Uranium Project (Project Totals)	n/a	n/a	2,754	n/a	n/a	773	n/a	n/a	3,527	n/a	n/a	308
Alta Mesa Project	263.7	0.1	691.4	630.0	0.2	1,894.5	630.0	0.1	2,585.9	2,223.4	0.1	5,200.5
Mesteña Grande Project	-	-	-	-	-	-	-	-	-	5,853	0.119	13,888
Region: South Dakota												
Dewey Burdock Project	5,419.8	0.132	14,2856	1,968.4	0.07	2,836.2	7,388.2	0.12	17,122.1	645.5	0.06	712.6
Region: Wyoming												
Gas Hill Project	994.0	0.10	2,051.0	2,835.0	0.10	5,654.0	3,829.0	0.10	7,705.0	409.0	0.05	428.0
Total Mineral Resources	-	-	19,782.4	-	-	11,157.7	-	-	30,940.0	-	-	20,537.0

Notes:

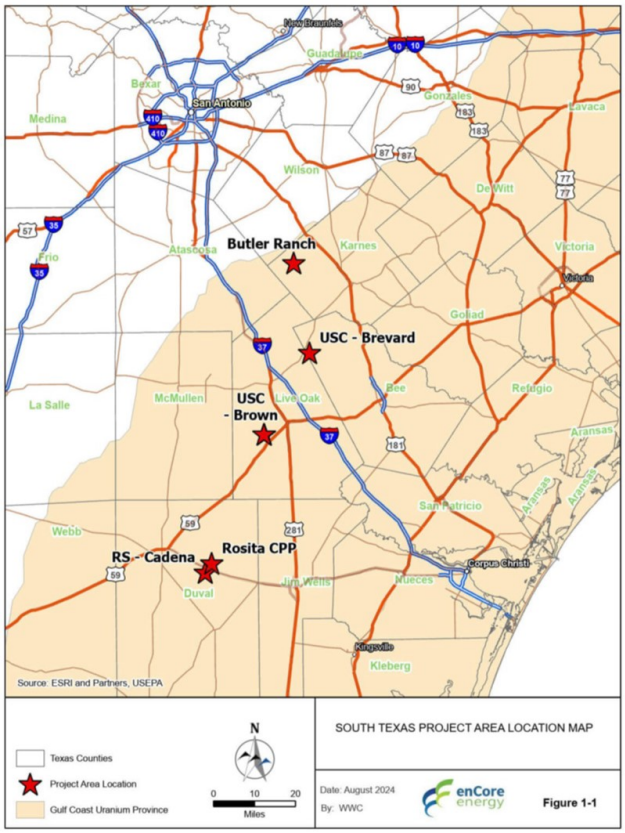
1. The Mineral Resource estimates in this table comply with the requirements of S-K 1300.
2. Mineral Resources were estimated using the following prices: (a) the South Texas Integrated ISR Project used a variable U_3O_8 sales price ranging from $78.37/lb up to $92.04/lb with an overall average U_3O_8 sales price of $87.05/lb (b) Alta Mesa Project used a uranium sales price that ranges from $82.00 to $89.00, with an average life of mine sales price of $83.43, (c) the Dewey Burdock Project used using a uranium sales price ranging from $82.00 to $89.00, with an average sales price of $86.34 .and (d) Gas Hills Project used a U_3O_8 sales price of $87.00/lb.
3. Mineral Resources were estimated using various %eU_3O_8 or G.T. cut-off grades. The following are the averages for Measured and Indicated Resources: (a) the South Texas Integrated ISR Project used 0.2 to 0.3 GT cutoff with avg GT values ranging between 0.40 and 2.15, (b) the Alta Mesa Project used 0.145 %U_3O_8, (c) the Mesteña Grande Project had no Measured or Indicated resources, (d) the Dewey Burdock Project used 0.12 % U_3O_8 (0.66 avg. GT) and (e) the Gas Hills Project used 0.10 % U_3O_8 (0.502 avg. GT).
4. The South Texas Integrated ISR Project includes Mineral Resources from the Upper Spring Creek Brevard, Upper Spring Creek – Brown and Rosita South – Cadena project areas.

Material Properties

South Texas Integrated ISR Project (Rosita CPP)

The South Texas Integrated ISR Project and associated well fields (collectively, the "STX Integrated") is comprised of the Rosita CPP located in Duval County on a 200-acre tract owned by the Company, and multiple associated Satellite IX facilities at various project sites across south Texas. The STX Integrated project is located within the South Texas uranium province, about 22 miles west of the town of Alice. The Rosita CPP was constructed in 1990 and was originally designed and constructed to operate as an up-flow extraction facility. The Rosita property holdings consist of mineral leases from private landowners covering approximately 3,475 gross and net acres of mineral rights.

The STX Integrated, including the Rosita CPP, was the starting point for enCore's Texas production strategy. In the fourth quarter of 2023, the Company announced it had commenced uranium extraction operations at Rosita from the Rosita Extension wellfield ("Rosita Extension"), PAA-5. The Rosita CPP has an 800,000-pound U_3O_8 per year production capacity. At the Rosita CPP, 76,909 pounds U_3O_8 were extracted and packaged in the year ended December 31, 2024.



The following technical and scientific description of the STX Integrated is based in part on the report titled "*Technical Report on the South Texas Integrated Uranium Projects, Texas, USA*" dated February 4, 2025 and effective December 31, 2024, and prepared by Christopher McDowell, P.G. and Ray Moores P.E. each, a Qualified Person employed by WWC Engineering and is independent of the Company (the "**South Texas Technical Report Summary**"). The South Texas Technical Report Summary was prepared in accordance with S-K 1300. The STX Integrated does not have known "Mineral Reserves" and is therefore considered under SEC S-K 1300 definitions to be an Exploration Stage Property.

Property Description

The Rosita CPP is located in Duval County, Texas, approximately 13.7 miles east of Freer and approximately 60 miles west of Corpus Christi at latitude 27.830423 and longitude -98.403543 (decimal degrees). This facility represents the central location of the Project and includes the central processing facility where resin from each satellite facility will be processed. The Rosita CPP is supplied with uranium-loaded ion exchange resin from ISR mining at one or more of the project areas. The Rosita CPP initiated extraction in 1990 and extracted 2.65 million pounds of U_3O_8 from 1990 to 1999. The Rosita CPP restarted operations in 2023. This plant was originally constructed as an up-flow ion exchange facility in 1990, and its conversion to a CPP was completed in 2023. At the Rosita CPP, resin is processed, and uranium is recovered, precipitated as a slurry, and is then dried and packaged.

The Butler Ranch project consists of approximately 743 acres located in a rural area of Karnes County, Texas, approximately 44 miles south of San Antonio. It is centered at the approximate location of latitude 28.887336 and longitude -98.059851 (decimal degrees). Butler Ranch is comprised of four different non-connected property leases over approximately 10 miles in the western part of the county.

Upper Spring Creek- Brevard is located 6 miles northeast of the Ray Point Mining District in the Gulf Coast Uranium Province and South Texas Uranium Province or "GCUP"/"STUP" and is situated in Bee and Live Oak counties, Texas

approximately halfway between San Antonio and Corpus Christi. Brevard is situated at latitude 28.567478 and longitude -98.024910 (decimal degrees). Three properties form the Brevard project area (Benham, Brevard, and Johnston) and total approximately 1,110 acres.

Upper Spring Creek – Brown Area project is located approximately 12 miles south-southwest of Three Rivers, Texas at the intersection of FM 889 and County Road 135 in Live Oak County latitude 28.287518 and longitude -98.214002 (decimal degrees). Brown includes three properties totaling approximately 247 acres. The two properties (Brown and Geibel) located to the south and east of FM 889 are collectively referred to as the Brown property and the property to the west of FM 889 is the Geffert property. URI, Inc. owns both surface and mineral rights for the former Brown and Geffert properties and owns surface and leases mineral rights for the former Geibel property at this project location.

Rosita South-Cadena is located in Duval County, Texas, approximately 11.5 miles east of Freer and approximately 64 miles west of Corpus Christi at latitude.

Ownership

This STX Integrated is owned and operated by the Company. The Company has executed surface use and access agreements and fee mineral leases with surface and mineral owners at the STX Integrated. The net mineral ownership, royalty burden, and estimated annual costs are provided below for each of the projects:

Project	Gross Holdings Surface and/or Mineral (acres)	Net Mineral (acres)	Mineral Royalty Range	Estimated Annual Holding Costs
Butler Ranch	675	509	6% to 12% sliding scale based on Sales Price	9,344
Rosita	1772	1118	6.25% to 11.25% sliding scale based on Sales Price	72,277
Upper Spring Creek – Brevard	280	280	6% to 12% sliding scale based on Sales Price	14,000
Upper Spring Creek Brown Area	728	449	5% to 12% sliding scale based on Sales Price	7,275
Rosita South - Cadena	3619	2439	5% to 12% sliding scaled based on Sales Price	49,572

Accessibility

The Rosita CPP and Rosita South - Cadena are served by Texas State Highway 44. Texas State Highway 44 is a State maintained, two-lane, sealed, asphalt road providing year-round access. Two different County Roads “CR”, (CR 330 and CR 333) from Highway 44 are used as access to the Rosita CPP. County Road 330 provides access from Highway 44 while County Road 333 provides access to the Rosita CPP from County Road 330. From County Road 333 a private road is utilized into the Rosita CPP site. Cadena can also be accessed from County Roads (CR 321 and CR 3196). Commercial airlines serve both San Antonio and Corpus Christi. Many of the local communities have small public airfields and there are numerous private airfields in the region.

Butler Ranch is served by Texas Highway 181. Texas Highway 181 is a State maintained, four-lane, sealed, asphalt road providing year-round access. Multiple county roads from Highway 181 lead to the Butler Ranch project area. At Butler Ranch, there are crown-and-ditched mixed gravel and pavement access roads to the area. In addition to the designated routes, there are a few tertiary or ‘two-track’ roads that traverse the area for recreation and grazing access, as well as various other uses, including mineral and petroleum exploration.

Upper Spring Creek - Brevard is served by Texas State Highway 72. Highway 72 is a state-maintained, two-lane, sealed, asphalt road providing year-round access. Two different county roads (CR 147 and CR 231) from Highway 72 can be used to access Brevard.

Upper Spring Creek - Brown is served by U.S. Interstate Highway 37 (I-37). I-37 is a state-maintained, four-lane, sealed, asphalt road providing year-round access. Access to this highway from the west and northeast is U.S. Highway 72, access from the east and southwest is U.S. Highway 59. The area can also be accessed from the south via U.S. Highway 281

leading to U.S. Highway 37. Multiple county roads from U.S. Highways 281 and 59 lead to the Brown. Once on Brown, there are crown-and-ditched mixed gravel and pavement access roads to the area. The physical address of the property is 216 County Road (CR) 135, George West, in Live Oak County, Texas. Brown is located approximately 6.75 miles south-southwest of the intersection of U.S. Highway 281 and Farm-to-Market Road (FM) 889.

Infrastructure

Equipment, supplies and personnel needed for exploration and day-to-day operation are available from population centers such as San Antonio and Corpus Christi. Specialized equipment for the wellfields is often available in Texas but may need to be acquired from outside of the state. The local economy for all project areas is geared toward oil and gas exploration, energy production, and ranching operations, providing a well-trained and capable pool of workers for ISR production and processing operations. Workers will reside locally and commute to work daily. As a result of energy development since the early 1900s, all the project areas have existing or nearby electrical power, gas and adequate telephone and internet connectivity. Generally, the local and regional infrastructure is in place for all project areas including roads, power and maintenance facilities. The exceptions include local access roads, wellfield development, local power and well control facilities that must be constructed. Specific information about the available infrastructure for each project area is described below.

Rosita CPP - Projects

The Company currently owns and operates the Rosita CPP within the Rosita Project radioactive materials license and injection permit boundaries. Site infrastructure includes the Rosita CPP and associated infrastructure, electric transmission lines, water supply, ponds, and several paved and well-graded county roads that traverse the area providing access to the property. The remaining unused lands are primarily undeveloped farmland.

Butler Ranch

The Company leases the surface and mineral rights at Butler Ranch and has access to the land for exploration and development. Site infrastructure consists of residential buildings, undeveloped farmland, and retention ponds. Several paved and well-graded county roads traverse the area providing access to each property. Several electric transmission lines run adjacent to these roads and by the individual properties. Non-potable water will be supplied by water supply wells at or near the site. There is an existing water supply well at the STX Integrated, but additional water supply wells may need to be developed. Water extracted as part of ISR operations will be recycled for re-injection.

Upper Spring Creek - Brevard

The Company has or will obtain legal access to the land surface through confidential agreements.

Site infrastructure consists of land to support cattle ranching and agriculture. Several paved county roads provide access to Brevard. An overhead electric transmission line and underground phone line run parallel to CR 140. Non-potable water will be supplied by water supply wells at or near the site. There are two existing water supply wells at Brevard, but additional water supply wells may need to be developed. A public water system, El Oso Water Supply Corporation, also serves the area. Water extracted as part of ISR operations will be recycled for re-injection.

Upper Spring Creek – Brown

The Company owns both surface and mineral rights at the Brown and Geffert properties. The Company leases minerals located beneath the Geibel property and has access to the land for exploration and development.

Site infrastructure consists of residential buildings, undeveloped farmland, and retention ponds. Several paved and well-graded county roads traverse the area providing access to each property. Several electric transmission lines run adjacent to these roads and by the individual properties. Non-potable water will be supplied by water supply wells at or near the site. There is an existing water supply well at the Project, but additional water supply wells may need to be developed. Water extracted as part of ISR operations will be recycled for re-injection.

Rosita South - Cadena

The Company has obtained legal access to the land surface through confidential agreements.

Site infrastructure consists of residential buildings and land to support ranching and agriculture. Several paved and well-graded county roads traverse the area providing access to the property. Several electric transmission lines run adjacent to these roads to supply power to residential areas. No water supply sources have been developed for this site.

Geology, Mineralization and Deposit

The Project is located along the South Texas coastal plain, within the STUP. The uranium-bearing deposits in the STUP include sandstones in Tertiary formations ranging in age from Eocene (oldest) to Lower Pliocene (youngest). These permeable deposits are interbedded with claystones, mudstones and siltstones.

Uranium mineralization at the Project is typical of Texas roll-front sandstone deposits. The formation of roll-front deposits is largely a groundwater process that occurs when uranium-rich, oxygenated groundwater interacts with a reducing environment in the subsurface and precipitates uranium. The most favorable host rocks for roll-fronts are permeable sandstones with large aquifer systems. Interbedded mudstone, claystone and siltstone are often present and aid in the formation process by focusing groundwater flux. The roll-front deposits at Brevard are slightly different from the other roll-front deposits at Butler Ranch, Brown, and Cadena.

History

The STX Integrated is located in the South Texas Uranium Province. This province produced over 70 million pounds of U_3O_8 from 1954 through 1994. In recent years, mining companies have shifted from surface mining to ISR. Since 1975, the State of Texas has required the reclamation of surface mining operations.

Uranium exploration and mining in South Texas primarily targets sandstone formations throughout the Coastal Plain bordering the Gulf of Mexico. The area has long been known to contain uranium oxide, which was first discovered in Karnes County, Texas in 1954 using airborne radiometric survey. The uranium deposits discovered were within a belt of strata extending 250 miles from the middle coastal plain southwestward to the Rio Grande. This area includes the Carrizo, Whitsett, Catahoula, Oakville and Goliad geologic formations. Open pit mining began in 1961 and ISR mining was initiated in 1975. The uranium market experienced lower demand and price in the late 1970s and in 1980 there was a sharp decline in all Texas uranium operations.

During the late 1970s and early 1980s, exploration of uranium in South Texas had evolved towards deeper drilling targets within the known host sandstone formations. Deeper exploration drilling was more costly and excluded many of the smaller uranium mining companies from participating in the down-dip, deeper undrilled trend extensions. Uranium had been mined by several major oil companies in the past in South Texas, including Conoco, Mobil, Humble (later Exxon), Atlantic Richfield ("ARCO") and others. Mobil had found numerous deposits in South Texas in the past, including the O'Hern, Holiday-El Mesquite and several smaller deposits, mostly in Oligocene-age Catahoula Formation tuffaceous sands. ARCO discovered several Oakville Formation (Miocene-age) uranium-bearing deposits and acquired other deposits located nearby in Live Oak County. They were exploring deeper extensions of Oakville Formation trends when they discovered the Mt. Lucas Goliad Formation deposit, located near Lake Corpus Christi in Live Oak County near the Bee County line (Carothers 2011). Ownership, control, and operation of the project areas has varied greatly since the 1960s.

Permitting and Licensing

ISR projects in Texas require a number of permitting steps before recovery of uranium can commence. The first requirement is an exploration permit regulated by the Texas Railroad Commission. All of the sites have active exploration permits that allow drilling of exploration holes allowing enCore to collect data to determine if an economic ore body exists. The results of the drilling programs through exploration permits are used to define the resources on the associated property.

Once it has been decided to move towards production, an aquifer exemption must be obtained through the U.S. EPA. An aquifer exemption is an acknowledgment by the EPA that naturally occurring uranium exists in the aquifer in the designated area and that section of the aquifer is not suitable for use as a drinking water source.

Texas is an agreement state and has primacy over the permitting of Underground Injection Control "UIC" activities. The state agency that regulates the uranium recovery process is the TCEQ. An area permit is required to progress to the next stage. This stipulates the area in which production can be pursued on and the requirements regarding operations and reclamation of uranium ISR activities. Within the permitted areas, individual production area authorizations (PAA) must next be obtained. To obtain a PAA, monitor wells must be installed and pump tests conducted to verify connectivity within

the aquifer. Baseline wells must also be installed and analyses run to establish baseline testing. Bonding must be put into place prior to operations.

Current Permits for the STX Integrated are as follows:

Upper Spring Creek - Brown

Permit Type	Permit Number	Approved date	Current Status
Aquifer Exemption	EPA exemption ID: 6-114 – Boots/Brown	Jan. 1, 1982	Approved
Area Permit	URO3095	August 2, 2024	Approved
Area Permit	Application to expand Brown Area Permit to incorporate Geffert RO3653		Scheduled for 1H 2025
PAAs	Application to be submitted April 2025		
PAAs	Application to add PAA on Geffert property under Brown Area Permit		Scheduled for 2H 2025
WDW	WDW467		Submitted 9/9/2022 – under technical review
RML License	RO3653		Submitted 10/11/2022 – under technical review

Upper Spring Creek – Brevard

Permit Type	Permit Number	Approved date	Current Status
Aquifer Exemption	EPA exemption ID: 6-84 – Brevard	Jan. 1, 1982	Approved
Area Permit*	Submitted August 5th 2010		Requested termination Mar 28, 2018
PAAs*	Submitted September. 29, 2010	Apr. 8, 2011	Requested termination Mar 28, 2018
WDW*	2 permits WDW-428 & WDW-429. Submitted Jan. 28, 2010	Dec. 8, 2010	Signal Equities requested TCEQ revoke permits for WDW-428 and WDW-429 which TCEQ approved on Apr. 26, 2018.
RML License*	Oct. 21, 2009	Nov. 9, 2011	Expired Nov. 30, 2021. Signal Equities requested license termination Apr. 11, 2018.

Rosita South – Cadena

Permit Type	Permit Number	Approved date	Current Status
Aquifer Exemption	EPA ID: 6-75 – Rosita Extension	Jul. 1, 1998	Approved
Area Permit	Renewal application submitted Apr. 8, 2024. URO2880	Nov. 15, 2007. Has subsequently been renewed Oct. 10, 2014.	Approved. Renewal under review.

PAAs	N/A		PAA to be submitted once drilling identifies an orebody
WDW	WDW250		Active: Wastewater will be pipelined to existing Class I Byproduct Injection Wells. Rosita WDW at CPP.

Quality Assurance and Quality Control

Signal Equities, LLC, had written procedures for the collection of drill data including lithological logging, natural gamma logging, PFN logging, and also for data entry into databases and GIS. All drill hole data are now maintained at enCore's corporate office in Corpus Christi, TX. For the initial exploration of the Brevard and Brown properties, Signal Equities, LLC previously had written procedures for the collection of drill data including lithological logging, natural gamma logging, and PFN logging, and also for data entry into databases and GIS. All data were stored on a secure server at the Signal Equities corporate office in New Braunfels, TX, with a full copy backup at a secure off-site contract data storage facility. enCore has since acquired and retains all data collected by Signal Equities.

For the South Texas Technical Report Summary, the QP reviewed PFN logs, gamma logs and drilling records for each drill hole used to calculate mineral resources. The QP corrected errors that were identified in the previous owner's PFN calibration calculations and grade calculations using the raw logging data and known constants such as hole diameter and published DOE test pit grade values. Using the carefully verified and corrected data, the QP checked the GT contour and GIS data provided by enCore. Approximately 75% of all the drill hole data used to prepare the mineral resource estimate were validated by checking the corresponding PFN logs.

Data Verification

Butler Ranch

Data supporting the South Texas Technical Report Summary comes almost exclusively in the form of drilling data gained from historical drilling activities by previous operators and done since the acquisition of the STX Integrated. The tabulations of mineral intercepts compiled by the Company are consistent with the original down-hole gamma logs and the geophysical operator's mineral intercept calculations. WWC has verified historical drill data by comparing historical drilling and reports in the STX Integrated adjacent to historical exploration holes with results which validate the historical data. The tabulations of mineral intercepts compiled by the Company have been confirmed by the QP to be consistent with the original down-hole electric logs and the geophysical operator's mineral intercept estimate.

Furthermore, historical mineral intercept data of previous operators of Butler Ranch have been evaluated and selectively checked for accuracy.

Upper Spring Creek – Brevard

The Company provided the QP with access to the complete electronic dataset for Brevard for the purpose of preparing the South Texas Technical Report Summary. The QP did not review hard copy records, but the electronic dataset included scans of field data sheets. The QP verified all of the assay data used to prepare the mineral resource estimate. This verification included reviewing PFN tool calibration records and grade calculations, comparing core and PFN assay results, and reviewing each PFN log used in the mineral resource estimate.

Signal Equities, LLC's calibration records for the PFN tools were reviewed to confirm the tools were properly calibrated. The PFN calibration does not affect the raw data (epithermal and thermal neutron counts) measured by the PFN tool; it only affects how the U_3O_8 grades are calculated from the raw data.

The QP also reviewed the previous operator's U_3O_8 grade calculations to ensure the appropriate factors were used. The borehole correction factor is directly related to the drill hole diameter and should be the same for drill holes of the same size. The QP identified some logs (approximately seven percent of the logs used to prepare the mineral resource estimate) in which the incorrect borehole correction factor was used to calculate the U_3O_8 grade. As with the calibration calculation errors, this calculation does not affect the raw data measured by the PFN tool, it only affects how the U_3O_8 grades are calculated. The QP subsequently reviewed records for every drill hole that was used in the mineral resource estimate to

confirm that the correct borehole correction factor was used. The QP corrected the borehole correction factor errors and associated U_3O_8 grade calculations as necessary.

The QP compared core assay data with PFN assay data for ten core holes at the Brevard property. Results were compared by summing all intervals in a core hole that had both core and PFN assay data, to produce a grade sum. Initially, it appeared that the core assay results were higher than the PFN assay results. The PFN assay results were then corrected for the calibration and grade calculation errors as described above.

Sample recovery in two of the core holes was poor and records clearly indicate that the mineralized interval was not recovered, so the lab assay results are not representative. For the remaining eight core holes, the corrected PFN assay results were within -10.3% to +10.8% of the core assay results. The average difference was 0.5% (with the PFN assay 0.5% higher than the core assay). The results confirm that the methodology used to correct the PFN data is reliable, since the resulting data are independently supported by core assay data.

The QP reviewed the PFN logs of every drill hole used in the mineral resource estimate. PFN logs were compared against gamma logs to check that the results of the two independently run logs were similar. Although there were differences due to radiometric disequilibrium, both logs typically identified similar depths of mineralization and relative magnitude of response to mineral intercepts with respect to background levels. Since some PFN logs had high noise levels, each log was evaluated to ensure that PFN noise was not being incorrectly inferred as uranium. In noisy logs, only the clearly mineralized intervals with responses higher than background noise (as verified by corresponding gamma responses) were included in the Grade-Thickness sum or "GT" sum.

Upper Spring Creek – Brown

The Company maintains digital copies of data at their office in Corpus Christi, TX. All PFN log data for the STX Integrated area was provided digitally by the Company. The PFN records included the raw data files collected by the logging tool (LAS files) and calculations of the PFN grades. Approximately 75% of all the logs used for the STX Integrated area were reviewed by the QP. In the opinion of the QP, the mineralized intervals previously defined by enCore for the South Texas Technical Report Summary were valid.

In addition, GT contours were provided by enCore for mineralized zones throughout Brown. These zones were referred to as the A, C (separated into upper and lower sub-zones), D (separated into upper and lower sub-zones), E, and F Sand Zones in the Brown property and Sand 4, 3c, 3b, 3, 2 and 1 in the Geffert property. Contours for each mineralized sand zone were then directly compared to the mineral intercept data on PFN logs. After reviewing and editing these contours for accuracy, it is the QP's opinion that the contours provided by enCore for the South Texas Technical Report Summary were valid. Much of the data for Brown came from Signal's 2010 drilling program. Therefore, calibration of the down hole geophysical logging instruments was vital to providing accurate data. While drilling, both the natural gamma and PFN logging trucks were calibrated routinely. In both 2009 and 2010, according to calibration records, the PFN tools were calibrated on 37 separate occasions while Signal records indicate that the Mt. Sopris® tools were 'routinely' calibrated. Natural gamma tool and PFN tool calibration was performed at the George West, TX facility, which is maintained by the DOE (Signal Equities 2017). During the data verification process, the QP determined that the PFN tool calibration grade used by the logging contractor was not the published grade for the George West, TX calibration test pit. This error in calibration grade affected the calculated grades of U_3O_8 on drill holes logged after the PFN tool was calibrated to the incorrect grade. The records indicate that aside from the calibration grade, the PFN tool runs in the calibration pits were performed per normal accepted protocols. The PFN calibration does not affect the raw data (epithermal and thermal neutron counts) measured by the PFN tool; it only affects how the U_3O_8 historical calibration calculation error and associated U_3O_8 grade calculations. The QP also identified some logs in which the incorrect borehole correction factor was used to calculate the U_3O_8 grade. The QP subsequently reviewed records for every drill hole that was used in the mineral resource estimate to confirm that the correct borehole correction factor was used. As with the calibration calculation errors, this calculation does not affect the raw data measured by the PFN tool, it only affects how the U_3O_8 grades are calculated. The QP was able to correct the borehole correction factor errors and associated U_3O_8 grade calculations. During enCore's 2022-2024 drilling program PFN tools owned by enCore were used for logging. These PFN tools were regularly calibrated at the test pits at Kingsville Dome and the calibration pits at George West.

Radioactive isotopes decay until they reach a stable non-radioactive state. The radioactive decay chain isotopes are referred to as daughters. When all the decay products are maintained in close association with the primary uranium isotope U_{238} on the order of a million years or more, the daughter isotopes will be in equilibrium with the parent isotope. Signal relied on PFN log data for determination of uranium grade. This method is a direct measurement of U_3O8 content rather than an equivalent U_3O_8 estimate. Therefore, the DEF is unnecessary and not applicable. Wet chemical assays were performed on three cores from the core holes drilled at the Project. The results of the PFN data and the core assays are inconsistent and

due to the limited number of core holes, the dataset is too small to determine why the assay results are inconsistent with the PFN data. Brevard was cored at the same time with the same coring rigs, PFN equipment, and operators have a larger set of coring records. Records from this nearby project show that the coring recovery was sometimes poor, especially in sands (i.e., mineralized zones). There were also problems with swelling clays expanding in the core tubes, which affected the core sample depths. When the coring recovery at the nearby project was good, the grade sums measured by the core assay and PFN (corrected) matched closely.

Rosita South – Cadena

No data is available for the calibration of any geophysical logging tools used on the STX Integrated. However, it is assumed that the PFN and gamma data used in this mineral estimate were calibrated to industry standards. Assay data compared to the mineral grades used to calculate the Grade-Thickness "GT" values in the mineral estimate were comparable and the grades used to calculate the GTs were conservative in some cases. Therefore, it was the QP's opinion that the data used in the STX Integrated is valid and suitable for estimating Mineral Resources.

Mineral Extraction Activities

The following table shows the extraction history from January 1, 2024 to December 31, 2024, from the STX Integrated:

Project	2024
South Texas Integrated ISR Project (dried and packaged)	
Pounds U_3O_8 (000)	77.7

Mineral Resources

The STX Integrated Mineral Resources have a reasonable prospect for economic extraction due to the depth of mineralization, GT values, and continuity of mineralization. Studies completed to date support the conclusion that the STX Integrated deposits could be mined through ISR. The Mineral Resource estimates presented in the South Texas Technical Report Summary use cutoffs that are appropriate for ISR mining and may not be applicable to other mining methods.

Some of the shallower STX Integrated Mineral Resources and exploration targets may not be fully saturated. Deeper STX Integrated deposits are fully saturated, and there are ISR techniques that can be used to recover uranium from partially saturated or unsaturated deposits. These techniques include the use of alternate oxidants, water transfers and aquifer enhancement.

Mineral reportable as Mineral Resources meets the following cutoff criteria:

- Minimum Grade: 0.020 %U_3O_8

Grade is calculated at 0.5 ft depth increments, and values below this cutoff are excluded from reported resources.

- Minimum GT (Grade x Thickness):
  - 0.30 for Brevard, Cadena, and the measured resources at Brown
  - 0.20 for the indicated and inferred resources at Brown

The GT cutoff is applied to mineral horizons, and values below this cutoff are excluded from reported resources.

No specific minimum thickness is applied; however, the grade is calculated at 0.5 ft depth increments, making this the minimum possible thickness. It is the QP's opinion that the cutoffs used in this Report are typical of ISR industry standard practice and are appropriate for current ISR methods.

The following key assumptions were used for all resource estimates:

- Resources are in permeable and porous sandstones; and
- Resources are located below the water table.

Mineral resource estimation methods used for the project areas include the GT contour and Polygonal. Mineral resources were estimated separately for each of the project areas.

Summary of Uranium Mineral Resources at the South Texas Integrated ISR Project as of December 31, 2024
(Based on a metal price of $87.05/lb. U_3O_8)

Project Area	GT Cutoff	Average GT	U3O8 (lbs)
Upper Spring Creek – Brevard Area			
Measured	0.30	0.59	800,000
Indicated	0.30	0.40	38,000
Total Measured and Indicated			838,000
Upper Spring Creek – Brown Area			
Measured	0.30	1.17	1,339,000
Indicated	0.20	2.15	720,000
Total Measured and Indicated			1,339,000
Rosita South – Cadena			
Measured	0.30	0.80	615,000
Indicated	0.30	0.42	15,000
Total Measured and Indicated			630,000
Upper Spring Creek – Brown			
Total Inferred	0.20	1.36	308,000

Notes:
1. Mineral resources as defined in S-K 1300.
2. All resources occur below the static water table.
3. The point of reference for mineral resources is in-situ at the Project.
4. Mineral resources are not mineral reserves and do not have demonstrated economic viability.
5. An 80% metallurgical recovery factor was considered for the purposes of the economic analysis.
6. There are no measured or indicated resources at Rosita CPP or Butler Ranch.

Mining, Processing and Recovery Methods

A central processing plant (CPP) and Satellite facility will collect and process uranium. The CPP processing circuits will consist of elution, precipitation, dewatering, drying and packaging. The Satellite facility will include an ion exchange circuit (IX) and a resin transfer system to facilitate transfer of loaded resin by truck from the Satellite to the CPP.
The CPP is located at the existing Rosita Central Plant property and Satellites will be located at each of the identified locations.

Mining Method

enCore will mine uranium using the in-situ recovery (ISR) method. ISR has historically been utilized at the STX Integrated and is relatively environmentally benign when compared to conventional open pit or underground recovery techniques. This mining method utilizes injection wells to introduce a mining solution, called lixiviant, into the mineralized zone. An alkaline leach solution of carbon dioxide and oxygen added to the native groundwater, will be used as the lixiviant. Bicarbonate, resulting from the addition of carbon dioxide to the extracting solution, will be used as the complexing agent. Oxygen will be added to oxidize the uranium to a soluble +6 valence state. Recovery wells are used to remove the solution from the formation where it is piped to a processing plant. An ion exchange (IX) column is used to remove the dissolved uranyl carbonate from the solution. The groundwater is re-fortified with the oxidizer and complexing agent and sent back to the wellfield to recover additional uranium. To use ISR, the mineralized body must be saturated with groundwater, transmissive to water, and amenable to dissolution by the lixiviant. Previous operations have demonstrated uranium mineralization within the Project area is recoverable using the proposed ISR techniques.

Mine Design and Plans

The fundamental production unit for design and production planning or scheduling is the pattern. A pattern is comprised of a production or recovery well, and some number of injection wells. Patterns are typically configured in a five or seven well configuration. A five well, or five-spot well pattern consists of one recovery and four injection wells generally in a square or near-square configuration. A seven well or seven-spot well pattern, like the five-spot, is comprised of a recovery well surrounded by six injection wells in a hexagon or near-hexagon configuration. In areas where the ore is not as widespread to allow for these patterns, encore will utilize an alternative line drive pattern placed over the recovery zone with wells alternating between production and injection wells. Pattern design is determined by the size and shape of the deposit,

hydrogeological properties of the mining formation, and mining economics. enCore plans to use a combination of five-spot and alternating line drive patterns with recovery wells spaced 50-100 feet from injection wells.

Patterns are grouped into production units referred to as wellfields. Wellfields form a practical means for design, development and production, where groups of recovery wells and their associated injection wells are designed, constructed and operated, serving as the fundamental operating unit for distribution of the alkaline leach system.

An economic wellfield must cover the construction costs associated with well installation, connection of wells to piping that conveys the leach system between wellfields and the IX facility, wellfield and plant operating costs, and reclamation costs.

To further facilitate planning, wellfields are grouped into production areas (PAs). Production areas represent a collection of wellfields for which baseline data, monitoring requirements, and restoration criteria have been established, for development of a Wellfield Hydrologic Data Package that will be submitted to regulatory authorities for mining approval. In Texas, this is known as a Production Authorization Area (PAA) in which the area and baseline restoration standards are specified in the permit.

Wellfields will typically be developed based on conventional five-spot or alternating line drive patterns. Injection and recovery wells will be completed in a manner to isolate the screened uranium-bearing interval. To establish baseline data, monitoring requirements, and restoration criteria, monitor wells will be installed for each mine unit. Baseline production zone monitor wells will be completed in the deposit hosting sandstone unit to establish baseline water restoration criteria.

Production zone monitor wells will also be installed in a ring around the entire wellfield. This ring of perimeter monitor wells will be setback approximately 400 feet from the patterns and 400 feet apart, respectively. Certain exceptions can be made to this distance based upon land and ore outline limitations when approved in the permit. This monitor well ring will be used to ensure mining fluids are contained within wellfield.

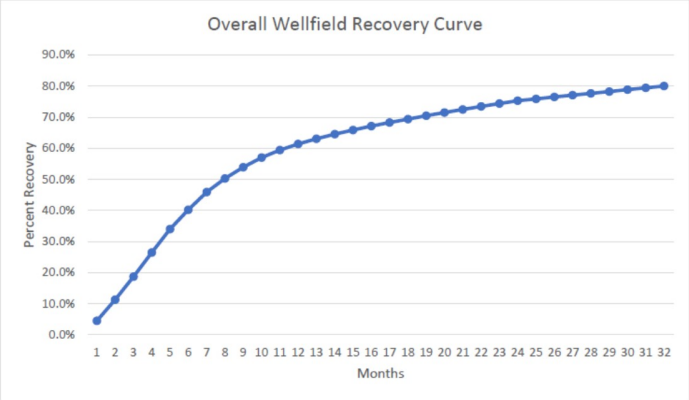
Overlying and underlying monitor wells will also be completed in hydro-stratigraphic units immediately above and below the production zone to monitor the potential for vertical lixiviant migration. Overlying monitor wells will be completed in all overlying units. Underlying wells will be completed in the immediately underlying unit.

Each injection and production well will be connected within a network of high-density polyethylene (HDPE) piping to an injection or production manifold located in the wellfield. The manifolds are connected to pipes that convey leaching solutions to and from the ion exchange columns in the CPP or Satellite facility. Flow meters, control valves, and pressure gauges in the individual well piping will monitor and control the individual well flow rates. Wellfield piping will be constructed using high-density polyethylene pipe.

The proposed uranium ISR process will involve the dissolution of the water-soluble uranium compound from the mineralized host sands at near neutral pH ranges. The lixiviant contains dissolved oxygen and carbon dioxide. The oxygen oxidizes the uranium, which is complexed with the bicarbonate formed by addition of carbon dioxide to the solution. The uranium-rich solution will be pumped from the recovery wells to the nearby CPP or Satellite facility for uranium concentration with ion exchange (IX) resin. A slightly greater volume of water will be recovered from the mineralized zone hydro-stratigraphic unit than injected, referred to as “bleed”, to create an inward flow gradient towards the wellfields. Thus, overall recovery flow rates will always be slightly greater than overall injection rates. This bleed solution will be disposed, as permitted, via injection into Class I DDW’s.

Production Rates and Expected Mine Life

Production rate was calculated using a production model derived from recent wellfields operating in the South Texas region. The production model was applied to mineral resources based upon the observed monthly recovery with a recovery of 80% in 32 months. The figure below depicts the production forecast model for the wellfields.



Processing and Recovery

A central processing plant (CPP) and Satellite facility will collect and process uranium. The CPP processing circuits will consist of elution, precipitation, dewatering, drying and packaging. The Satellite facility will include an ion exchange circuit (IX) and a resin transfer system to facilitate transfer of loaded resin by truck from the Satellite to the CPP.

The CPP is located at the existing Rosita Central Plant property and Satellites will be located at each of the identified locations.

Ion Exchange

Uranium will be recovered from pregnant lixiviant solution using the ion exchange circuit. Each vessel is designed to contain a 300 cubic foot batch of anionic ion exchange resin. The satellite design is based upon modules with a nominal capacity of 800 gallons per minute. Additional modules can be added to increase capacity based upon in place reserves and timing of the system. Each module will be configured with three tanks operating in series, utilizing pressurized down-flow methodology for loading. Piping and valving allows the flow to be redirected to any of the three tanks and change the order of flow between the tanks in order to allow for resin transfer and optimizing resin loading. Production and Injection booster pumps will be located upstream and downstream of the trains, as needed for wellfield conditions.

Vessels will be designed to provide optimum contact time between pregnant lixiviant and IX resin. An interior stainless-steel piping manifold system will distribute lixiviant evenly across the resin. The dissolved uranium in the pregnant lixiviant will bond to the ion exchange resin in exchange for a pre-existing chloride ion. The resultant barren lixiviant exiting the vessels will contain less than 2 ppm of uranium and will be returned to the wellfield where oxygen and carbon dioxide will be added prior to reinjection.

Bleed

A bleed will be drawn from the injection stream prior to reinjection into the wellfield to maintain control of hydraulic conditions in production zone. The bleed will be directed through filters and then to storage tanks and then to an onsite non-hazardous Class I disposal well. The water in the storage tanks will also be utilized for resin transfers and tank backwashes as needed.

Elution Circuit

Loaded resin will be transferred to the CPP via truck and trailer where an elution circuit will strip uranium from the resin with a sodium chloride and sodium carbonate brine solution forming a uranium rich eluant. The pH will be controlled with sodium hydroxide. Eluted resin will then be rinsed and returned to the IX vessels for reloading.

The elution circuit will consist of three eluant tanks and an elution tank. All three tanks will have the described eluant, but based upon the order of stripping, will have different grades of uranium in them. The contents of tank one will be pumped through the elution tank containing the resin and then into a precipitation tank. Next, the eluant in tank two will run through

the eluant tank with resin, and into tank one. Tank three consisting of fresh eluate with no uranium will be the final step to remove the last of the remaining uranium from the resin. It will be pumped through the eluant tank and will be deposited in tank two. A fresh batch of eluant will be made once depleted. The resin should now be mostly barren of uranium and is ready to be reused in a wellfield.

Precipitation Circuit

Hydrochloric acid will be added to the uranium rich eluant in the precipitation tank to bring the pH down to the range of 2 to 3 where the uranyl carbonate breaks down, liberating carbon dioxide and leaving free uranyl ions. Next, sodium hydroxide (caustic soda) will be added to raise the pH to the range of 4 to 5. After this pH adjustment, hydrogen peroxide will be added in a batch process to form an insoluble uranyl peroxide (UO2O2.H2O) compound. After precipitation, the uranium precipitate slurry is pumped to a filter press where the uranium solids are separated from the barren precipitation fluid. The liquid from the precipitation circuit is sent to a settling pond where it is appropriately neutralized and injected in a non-hazardous, class I disposal well.

Filtering, Drying and Packaging

After precipitation, yellowcake is removed for filtering, washing, drying and product packaging in a controlled area. The yellowcake in the filter press is washed with fresh water to remove excess chlorides and other soluble contaminants. The filter cake is transferred to a yellowcake storage bin for settling, decanting, and loading directly into the yellowcake dryer.

The yellowcake will be dried in a rotary vacuum dryer. The dryer is an enclosed unit and heated by circulating thermal fluid through an external jacket at ~450F. The off gases generated during the drying cycle, which will be primarily water vapor, are filtered through a bag house to remove entrained particulates and then condensed. Compared to conventional high temperature drying by multi-hearth systems, this dryer will have no significant airborne particulate emissions.

The dried yellowcake will be packaged into 55-gallon drums for storage before transport by truck to a conversion facility.

The yellowcake drying and packaging stations will be segregated within the processing plant for worker safety. Dust abatement and filtration equipment will be deployed in this area of the facility. Filled yellowcake drums will be staged in a dedicated storage area until transport.

Following standard industry protocols, yellowcake will be transported to a conversion facility in 55-gallon steel drums. The shipment method will be via specifically licensed trucking contractor.

Water Balance

The water balance is based on a production flow rate of 800-1000 gpm per satellite module with a 1% or 8-10 gpm bleed to maintain hydraulic control of fluids within the mine units. In the CPP water will be used for make-up and washdown at a rate of approximately 12 gpm from a local fresh water supply well. Restoration activities will include feed to a two-stage reverse osmosis unit (RO), with a 75% recovery rate to the wellfield. 25% of flow will be a concentrate and will be disposed of through a class I non-hazardous disposal well.

Liquid Waste Disposal

Class I non-hazardous waste disposal wells will be the sole method for liquid waste disposal. Liquid waste will be injected and isolated from any underground source of drinking water.

Solid Waste Disposal

Waste classified as non-contaminated (non-hazardous, non-radiological) will be disposed of in the nearest permitted sanitary waste disposal facility. Waste classified as hazardous (non-radiological) will be segregated and disposed of at the nearest permitted hazardous waste facility. Radiologically contaminated solid wastes, that cannot be decontaminated, are classified as 11.e.(2) byproduct material. This waste will be packaged and stored on site temporarily, and periodically shipped to a licensed 11.e.(2) byproduct waste facility or a licensed mill tailings facility.

Economic Analysis

The South Texas Technical Report Summary contains an Initial Assessment which indicates a pre-tax Net Present Value of $104.3 million at an 8% discount rate compared to an after- tax Net Present Value of $81.8 million at an 8% discount rate.
The South Texas Technical Report Summary contemplates an annual production of just over 0.5 million pounds in the first year and then ramping up to approximately 0.8 million pounds by the second year. Total life of the project is estimated at approximately 9 years (6 years production followed by 3 years of restoration/surface reclamation). The NPV assumes cash flows take place in the middle of the periods and is calculated based on a discounted cash flow. The production estimates, Capital Expenses, and Operating Expenses, cost distributions used to develop the cash flow are based on the production and restoration models developed by enCore and incorporated in the cash flow. The cash flow assumes no escalation, no debt, interest, or capital repayment. The initial capitalized STX Integrated project construction was completed prior to this analysis. Excluding sunk costs which occurred prior to the operations proposed in the analysis, the STX Integrated is estimated to generate net cash flow over its life, before income tax, of $123.96 million and $97.01 million after income tax.

The mine plan and economic analysis are based on the following assumptions:

- NI 43-101 and S-K 1300 compliant estimate of Mineral Resources and a recovery factor of 80%,
- A variable U_3O_8 sales price ranging from $78.37/lb up to $92.04/lb with an overall average U_3O_8 sales price of $87.05/lb,
- A mine life 9 years (6 years production followed by 3 years of restoration/surface reclamation),
- A pre-income tax cost including royalties, state and local taxes, operating costs, and capital costs of $43.12/lb, and costs for the Project are based on actual costs from enCore's currently operating south Texas ISR projects, economic analyses for similar ISR uranium projects, and WWC's in house experience with mining and construction costs. All costs are in U.S. dollars (USD).

This analysis above is based on Measured and Indicated Mineral Resources which do not have demonstrated economic viability. Given the speculative nature of mineral resources, there is no guarantee that any or all of the mineral resources included in the Initial Assessment will be recovered. The Initial Assessment is preliminary in nature and there is no certainty that the Project will be realized.

Capital Costs Estimate

	Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	Totals	$/lb
Pre-Construction Permitting Costs	US$000s	$ 150	$ 150	$ 300	$ -	$ -	$ -	$ -	$ -	$ -	$ 600	$ 0.21
Plant Development Costs	**US$000s**	**$ (7,656)**	**$ (5,377)**	**$ (296)**	**$ -**	**$ (267)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (13,596)**	**$ (4.82)**
Vehicles and Rolling stock	US$000s	$ (412)	$ (721)	$ (296)	$ -	$ (267)	$ -	$ -	$ -	$ -	$ (1,696)	$ (0.60)
Rosita South Remote IX	US$000s	$ -	$ (825)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (825)	$ (0.29)
USC Brown Unit Remote IX[1]	US$000s	$ (7,244)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,244)	$ (2.57)
USC Brevard Unit Remote IX[1]	US$000s	$ -	$ (3,831)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,831)	$ (1.36)
Well Feld Development Costs	US$000s	$ (9,208)	$ (13,780)	$ (11,401)	$ (6,895)	$ (1,564)	$ (323)	$ -	$ -	$ -	$ (43,172)	$ (15.30)
USC Brown Unit Wellfield	US$000s	$ (9,208)	$ (11,282)	$ (4,142)	$ (991)	$ (98)	$ -	$ -	$ -	$ -	$ (25,722)	$ (9.12)
Rosita South Wellfield	US$000s	$ -	$ (2,498)	$ (3,064)	$ (759)	$ (192)	$ -	$ -	$ -	$ -	$ (6,514)	$ (2.31)
USC Brevard Unit Wellfield	US$000s	$ -	$ -	$ (4,195)	$ (5,145)	$ (1,274)	$ (323)	$ -	$ -	$ -	$ (10,937)	$ (3.88)
Surface Damage Payments[2]	US$000s	$ (66)	$ (66)	$ (84)	$ (124)	$ (124)	$ (114)	$ (108)	$ (108)	$ (108)	$ (899)	$ (0.32)
Land Acquisition and Annual Rentals[3]	US$000s	$ (111)	$ (69)	$ (95)	$ (95)	$ (95)	$ (95)	$ (95)	$ (95)	$ (95)	$ (843)	$ (0.30)
Exploration[4]	US$000s	$ (858)	$ (1,029)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,887)	$ (0.67)
Total	**US$000s**	**$ (17,749)**	**$ (20,171)**	**$ (11,575)**	**$ (7,114)**	**$ (2,050)**	**$ (532)**	**$ (202)**	**$ (202)**	**$ (202)**	**$ (59,797)**	**$ (21.19)**

Notes:

1.) Estimate includes instalation of a 3,200 GPM Satellite IX plant . Includes a waste disposal well at an estimated cost of $2.5 million per well.

2.) Represents an average withdrawal rate for each property based on existing leases and surface use agreements.

3.) Based on acqusition plans and estimated based on current leasing experience

4.) Based on development plans, assuming lease aqusitions are successful.

Operating Costs Estimate

	Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	Totals	$/lb
Plant and Wellfield Operating Costs	**US$000s**	**$ (7,550)**	**$ (9,111)**	**$ (9,687)**	**$ (9,187)**	**$ (2,074)**	**$ (531)**	**$ -**	**$ -**	**$ -**	**$ (38,140)**	**$ (13.52)**
Rosita CPP Operating Costs	US$000s	$ (4,205)	$ (4,887)	$ (5,196)	$ (4,927)	$ (1,112)	$ (285)	$ -	$ -	$ -	$ (20,612)	$ (7.31)
Rosita South Operating Costs	US$000s	$ -	$ -	$ (2,402)	$ (544)	$ (185)	$ -	$ -	$ -	$ -	$ (3,131)	$ (1.11)
USC Brown Unit Operating Costs	US$000s	$ (3,345)	$ (4,224)	$ (2,090)	$ (521)	$ (53)	$ -	$ -	$ -	$ -	$ (10,233)	$ (3.63)
USC Brevard Unit Operating Costs	US$000s	$ -	$ -	$ -	$ (3,195)	$ (724)	$ (246)	$ -	$ -	$ -	$ (4,165)	$ (1.48)
Total D&D and Restoration Costs[1, 2]	**US$000s**	**$ -**	**$ -**	**$ -**	**$ (451)**	**$ (1,165)**	**$ (1,514)**	**$ (993)**	**$ (223)**	**$ (46)**	**$ (4,393)**	**$ (1.56)**
Rosita South D&D and Restoration	US$000s	$ -	$ -	$ -	$ -	$ -	$ -	$ (602)	$ (136)	$ (46)	$ (785)	$ (0.28)
USC Brown D&D and Restoration	US$000s	$ -	$ -	$ -	$ (451)	$ (1,165)	$ (714)	$ (210)	$ (25)	$ -	$ (2,565)	$ (0.91)
USC Brevard Unit D&D and Restoration	US$000s	$ -	$ -	$ -	$ -	$ -	$ (801)	$ (181)	$ (62)	$ -	$ (1,044)	$ (0.37)
Administrative Support[3]	US$000s	$ (535)	$ (518)	$ (535)	$ (535)	$ (535)	$ (535)	$ (535)	$ (535)	$ (535)	$ (4,797)	$ (1.70)
Conversion and Shipping fees[4]	US$000s	$ (253)	$ (320)	$ (340)	$ (322)	$ (73)	$ (19)	$ -	$ -	$ -	$ (1,326)	$ (0.47)
Reclamation Bonding Surity Costs[5]	US$000s	$ (298)	$ (306)	$ (323)	$ (323)	$ (323)	$ (323)	$ (321)	$ (320)	$ (318)	$ (2,856)	$ (1.01)
Bond collatoral	US$000s	$ (196)	$ (105)	$ (215)	$ -	$ -	$ -	$ 98	$ 92	$ 98	$ (228)	$ (0.08)
Total	**US$000s**	**$ (8,832)**	**$ (10,360)**	**$ (11,100)**	**$ (10,818)**	**$ (4,170)**	**$ (2,922)**	**$ (1,752)**	**$ (985)**	**$ (801)**	**$ (51,741)**	**$ (18.34)**

Notes:

1) Assumes TCEQ approval of restoration table amendment for groundwater release, and initiation of surface reclamation with onsite staff and estimated costs for groundwater restoration at Rosita PAA#3
2) Estimated costs for groundwater restoration and surface decommisioning based on operating experience by corporate and operational management.
3) Based on actual costs for South Texas General and Administrative costs.
4) Includes transportation, weighing and sampling costs, and transfer fees from ConverDyn and other costs.
5) Premiums and collateral based on current bonding structure with current underwriter.

Taxation and Royalties

The results of the analyses presented herein provide for pre-income tax and post-income tax estimates. The post tax estimate includes U.S. federal income taxes. There is no State of Texas income tax. Texas does not have a severance tax on uranium mining. Ad valorem taxes would be assessed at the individual county level based on the value of the project. Actual tax rates will vary based on the county mill levies. For the purposes of this analysis the ad valorem taxes were based on average rates paid on Encore's existing properties.

Various production royalties exist on the Projects. Due to the sensitive nature of royalty negotiations on existing and future properties, intimate details on the royalties are not provided. However, for the purposes of this analysis the Royalty rates were estimated as follows:

- At Brown the royalty is estimated at 1.5 percent of gross revenue.
- At Brevard the royalty rate is estimated at 5 percent of gross revenue.
- At Cadena the royalty rate is estimated at 10 percent of gross revenue.

Sensitivity Analysis

The STX Integrated is sensitive to changes in the price of uranium. A five percent change in the commodity price results in a $10.3 million change to the pre-tax Net Present Value "NPV" and $8.1 million to the post tax NPV at a discount rate of 8%. The analysis is based on a variable commodity price per pound. The STX Integrated is also slightly sensitive to changes in OPEX costs. A 5% variation in Operating Expenses results in a $2.1 million variation in pre-tax NPV and $1.7 million to the post-tax NPV. A 5% variation in Capital Expenses results in a $2.6 million variation in the pre-tax NPV and $2.1 million to the post-tax NPV. This analysis is based on an eight percent discount rate and a variable commodity price per pound.

Exploration Target

Conventional rotary drilling and down-hole geophysical logging were the primary exploration method at the STX Integrated. An exploration target has also been identified at the Butler Ranch Project.

The ranges of potential quantity and grade of the exploration target are conceptual in nature. There has been insufficient exploration to define a mineral resource or mineral reserve. It is uncertain if further exploration will result in the target being delineated as a mineral resource. An exploration target was estimated for the Butler Ranch Project. Data evaluated to prepare the exploration target include Project maps, mineral trend maps, historical ore body maps, cross sections, logs, previous technical reports, correspondence, and historical resource estimates and reporting. An extensive review of

historical drill hole data was undertaken in order to estimate existing uranium resources within the property boundaries that have not been mined. Data from over 1,934 drill holes at Butler Ranch were evaluated.

This evaluation included the use of historical down-hole electric logs, drill hole location maps, a 2015 drilling project report, a data acquisitions summary, past memos and permits, and historical ore reserve estimates by Conoco in 1978 and 1981. In addition, log data was inventoried and includes summaries of mineralized drill hole intercepts with grade, thickness, and local survey coordinates for drill holes. Those projects without down-hole electric logs were evaluated for exploration potential which is detailed herein.

An exploration target was estimated for several of the properties within the Butler Ranch Project area. The table below contains the results from this estimate. These estimates were derived from historical maps with mineral intercept data. No data on these maps could be confirmed by drill logs so these resources could not be classified. These properties are clearly targets for further exploration in the future.

Historical maps were used to map exploration targets at Butler Ranch. These maps were developed by previous owners of Butler Ranch. The mineral intercept data on each map was evaluated and a 0.10 GT contour was drawn around the trend as a mineral outline. The area inside of the mineral outline was calculated using AutoCAD. Both a minimum GT (cutoff of 0.10) and a weighted average GT (0.37) were used with the weighted average of the nearby Turner property as the analog since this trend closely resembled the trends on the exploration target properties. The weighted average GT and the calculated trend areas were then used to calculate pounds using the same equation as the classified mineral estimate. The conversion constant (20) and tonnage factor (17.0) were used for the exploration target.

Four distinct trends were identified with the historical maps.

Rosita Butler Ranch – Exploration Target Estimate of U3O8 lbs						
Trend	**Property**	**Host Strata**	**Acreage**	**Area (ft2)**	**Estimated Pounds at GT Cutoff**	**Estimated Pounds Turner Analog**
1	Moczygemba	Tordilla	3.71	161,608	19,000	69,000
2	Zunker	Tordilla	14.08	613,325	72,000	264,000
3	Garcia	Dubuse/Stone switch	28.91	1,259,320	148,000	541,000
4	Dziuk	Tordilla	1.74	75,794	9,000	33,000
Totals				**2,110,047**	**248,000**	**907,000**

Planned Work

The Company's planned work will focus on commencing uranium extraction from Upper Spring Creek – Brown. The necessary initial steps include the completion of the regulatory approvals of the amendment to the Radioactive Materials License RO3653, Class I UIC non-hazardous liquid byproduct disposal well, and the Production Area Authorization. Additional planned work includes the installation of the wellfield patterns, wellfield infrastructure, and the satellite IX facility for the site. The intent of this work is to start uranium extraction in 2025. Additionally, the Company intends to conduct additional exploratory drilling on the Geffert property to identify additional Mineral Resources and increase confidence of the reported inferred Mineral Resources. In 2026, the Company will file applications to amend the RML RO3653 to incorporate Upper Spring Creek–Brevard and file applications for Class III and Class I Underground Injection Control permits for Upper Spring Creek–Brevard.

Alta Mesa Project (Alta Mesa CPP), Brooks County, TX

The Alta Mesa Project is a fully licensed and constructed CPP, located on over 203,000 acres of private land. Total operating capacity is currently approximately 1.5 million lbs. U_3O_8 per year. Alta Mesa historically produced approximately 4.6 million lbs. of U_3O_8 between 2005 and 2013, when full production was curtailed because of low uranium prices at the time by the previous owner.

The following technical and scientific description of the Alta Mesa Project is based in part on the report titled "Alta Mesa Uranium Project, Brooks County, Texas, USA, S-K 1300 Technical Report Summary" and "Alta Mesa Uranium Project, Brooks County, Texas, USA, National Instrument 43-101, Technical Report" dated February 19, 2025 and effective

December 31, 2024 prepared by Stuart Bryan Soliz, PG of SOLA Project Services. (the "Alta Mesa Technical Report Summary"). The Alta Mesa Technical Report Summary was prepared in accordance with S-K 1300. The Alta Mesa Project does not have known "Mineral Reserves" and is therefore considered under SEC S-K 1300 definitions to be an Exploration Stage Property.

Property Description and Location

The Alta Mesa Project is an Exploration Stage ISR uranium mining project located in south Texas. The Alta Mesa Project lies within the southern part of the South Texas Uranium Province. Uranium deposits in the South Texas Uranium Province extend from Starr County at the international border with Mexico northeastward through Zapata, Jim Hogg, Brooks, Webb, Duval, Kleberg, McMullen, Live Oak, Bee, Atascosa, Karnes, Wilson, Goliad, and Gonzales counties. The Alta Mesa Project is located entirely within private land holdings of the Jones Ranch. The Jones Ranch is an approximately 380,000-acre ranch that was founded in 1897, and enCore controls over 200,000 of the 380,000 acres with mineral leases and options for uranium exploration and development.

The Alta Mesa Project is comprised of the Alta Mesa Mining Lease and the Alta Mesa CPP. The Alta Mesa Project consists of 4,597 acres. The active mine and CPP are located on the Alta Mesa project area approximately 35.5 miles southwest of Falfurrias via US Highway 281 to Ranch Road 755 to Ranch Road 430 to CR 314 to CR 315, Encino, Texas 78353, in Brooks County, Texas.

Ownership

Mineral Rights

Royalty agreements have been established with mineral and surface owners. Furthermore, surface owners are paid an annual rental to hold the surface on behalf of enCore. Additionally, the agreements also provide for additional charges to the surface owner to cover surface damages and for reduction of husbandry grazing during field operations.

Amended and Restated Uranium Solution Mining Lease

The Uranium Solution Mining Lease, originally dated June 1, 2004, covers approximately 4,598 acres, out of the "La Mesteñas" Ysidro Garcia Survey, A-218, Brooks County, Texas and the "Las Mesteñas Y Gonzalena" Rafael Garcia Salinas Survey, A-480, Brooks County, Texas. These have been superseded by the Amended and Restated Uranium Solution Mining Lease dated June 16, 2016, as part of the share purchase agreement between enCore and the various holders of the Mesteña project. The Lease now comprises Tract 5 and a portion of Tracts 1, 4, and 6 of "W.W. Jones Subdivision", said tract being out of the "La Mesteña Y Gonzalena" Rafael Garcia Salinas Survey, Abstract N0. 480 and the "La Mesteñas" Ysidro Garcia Survey, Abstract No. 218, Brooks County, Texas. The Lease now covers uranium, thorium, vanadium, molybdenum, other fissionable minerals, and associated minerals and materials under 4,597.67 acres.

The term of the amended lease is fifteen (15) years which commenced on June 16, 2016, or however long as the lessee is continuously engaged in any mining, development, production, processing, treating, restoration, or reclamation operations on the leased premises. The amended lease can be extended by the Lessee for an additional 15 years.

The lease includes provisions for royalty payments on net proceeds, less allowable deductions, received by the Lessee. The royalties range from 3.1% to 7.5% depending on the price received for the uranium. The lease also calls for a royalty on substances produced on adjacent lands but processed on the leased premises. The table below illustrates royalty details.

Amended Uranium Solutions Mining Lease Royalties

Royalty Holders	Number of Acres	Lessor Royalty	Primary Term
Mesteña Unproven Ltd.	4,597.67 +/-	7.5% Market value > $95.00/lb. U_3O_8	15 years from amendment date with option for additional 15 years or as long uranium mining operations continue
Jones Unproven Ltd.	4,597.67 +/-	6.25% of Market Value > $65/lb. U_3O_8	15 years from amendment date with option for additional 15 years or as long uranium mining operations continue

Mesteña Unproven Ltd.	4,597.67 +/-	3.15% of Market Value > $65/lb. U_3O_8	15 years from amendment date with option for additional 15 years or as long uranium mining operations continue
Jones Unproven Ltd.	4,597.67 +/-	3.15% of Market Value > $65/lb. U_3O_8	15 years from amendment date with option for additional 15 years or as long uranium mining operations continue

Amended and Restated Uranium Testing Permit and Lease Option Agreement

The Uranium Testing Permit and Lease Option Agreement (see table below), originally dated August 1, 2006, covers all land containing mineral potential as identified through exploration efforts and covers uranium, thorium, vanadium, molybdenum, and all other fissionable materials, compounds, solutions, mixtures, and source materials; this agreement has been superseded by the Amended and Restated Uranium Testing and Lease Option Agreement dated June 16, 2016, as part of the share purchase agreement between enCore Energy and the various holders of the Mesteña project. It now covers 195,501 acres.

The term of the amended lease and option agreement is for eight (8) years which commenced on June 16, 2016. The amended lease and option agreement has been extended by the grantee for an additional seven (7) years by certain payments conducted in April 2024. The Lease Option was further amended to extend the lease option period by an additional five (5) years in June 2024.

Amended and Restated Uranium Testing Permit and Lease Option Agreements Royalties

Royalty Holders	Number of Acres	Lessor Royalty	Primary Term
Mesteña Unproven Ltd.	195.501 +/-	7.5% Market value > $95.00/lb. U_3O_8	8 years from amendment date with option for additional 7 years or as long uranium mining operations continue
Jones Unproven Ltd.	195.501 +/-	6.25% of Market Value > $65/lb. & </= $95/lb. U_3O_8	8 years from amendment date with option for additional 7 years or as long uranium mining operations continue
Mesteña Unproven Ltd.	195.501 +/-	3.15% of Market Value > $65/lb. U_3O_8	8 years from amendment date with option for additional 7 years or as long uranium mining operations continue
Jones Unproven Ltd.	195.501 +/-	3.15% of Market Value > $65/lb. U_3O_8	8 years from amendment date with option for additional 7 years or as long uranium mining operations continue

Surface Rights

The mineral leases and options include provisions for reasonable use of the land surface for the purposes of ISR mining and mineral processing. Alta Mesa is a fully licensed, operable facility with sufficient sources of power, water, and waste disposal facilities for operations and aquifer restoration. While the current staff level has been reduced, sufficient local personnel were available for mine operations. Alta Mesa LLC, either has in place or can obtain the necessary permits and/or agreements, and local resources are sufficient for current and future ISR operations within the Project. Amended surface use agreements have been entered into with all the surface owners on the various prospect areas as part of the Membership Interest Purchase Agreement between Energy Fuels Inc and the various holders of the Mesteña Project.

Amended surface use agreements have been entered into with all the surface owners on the various prospect areas as part of the Membership Interest Purchase Agreement between Energy Fuels Inc and the various holders of the Mesteña Project. These amended agreements, unchanged from those originally entered into on June 1, 2004, provide, amongst other things, for stipulated damages to be paid for certain activities related to the exploration and production of uranium.

Specifically, the agreements call for U.S. Consumer Price Index (CPI) adjusted payments for the following disturbances: exploratory test holes, development test holes, monitor wells, new roads, and related surface disturbances. The lease also outlines an annual payment schedule for land taken out of agricultural use around the area of a deep disposal well, land otherwise taken out of agricultural use, and pipelines constructed outside of the production area.

Surface rights are expressly stated in the lease and in general provide the lessee with the right to ingress and egress, and the right to use so much of the surface and subsurface of the leased premises as reasonably necessary for ISR mining. Open pit and/or strip mining are prohibited by the lease.

State and Local Taxes and Royalties

Ad valorem tax rates per $100 of taxable value applicable to tangible property and royalty for 2022 were as follows:

- Brooks County 0.773160
- Brooks County Rd and Bridge 0.072987
- Brooks County Independent School District 1.411298
- Brooks County FM FC 0.042863
- Brush Country Groundwater 0.015263

Accessibility

The Project is accessible year-round and is located approximately 11 miles west of the intersection of US Highway 281 (paved) and North Farm to Market Road 755 (paved), 22 miles south of Falfurrias, Texas.

Infrastructure

The Alta Mesa Project is well supported by nearby towns and services. Larger cities, Corpus Christi, McAllen and Laredo, are each about 100 miles or less from the site and are ready sources of materials and equipment. Major power lines are located across the Alta Mesa Project and are accessed for electrical service. The road system is comprehensive and well maintained and used for shipment of materials and equipment.

Human resources are employed from nearby population centers. Numerous local communities provide sources for labor, housing, offices and basic supplies. enCore utilizes local resources when and where possible supporting the local economy.

The site has uranium drill holes and related infrastructure (e.g., small mud pits temporarily constructed to facilitate drill operations and water supply ponds), trucks and other equipment, historic and new wellfields, a CPP, administration building, shop and warehouse, environmental office, logging building and test pits.

The site has telephone and internet service in the form of a T-1 fiber optics line. The CPP has an automated control and monitoring system that allows remote monitoring of the facility and includes fail safe systems that can shut down portions of the system in the event of an upset condition. The facility is also fully secured with on-site and remote monitoring.

Water supply for the Project is from established and permitted local wells. Liquid waste from the processing facility is disposed via deep well injection through two permitted Underground Injection Control "UIC" Class I disposal wells. Solid waste is disposed off-site at licensed disposal facilities. No tailings or other related waste disposal facilities are needed.

Other land uses and associated infrastructure include, water wells, agricultural stock tanks/ponds, an aircraft landing strip located approximately 1.4 miles West of the CPP, cattle/horse ranches, and numerous caliche pits. In addition, agricultural cattle and horse grazing occurs in portions of the Project area and hunting stands and blinds are scattered throughout the area and are connected through a series of roads and senderos.

Oil and gas-related infrastructure on the Project includes oil and gas exploration and production wells, tank batteries, and numerous transmission and gathering pipelines.

Geology, Mineralization and Deposit

The Texas Gulf Coast comprises the western flank of the Gulf of Mexico sedimentary basin with active deposition throughout the mid to late Mesozoic Era and into the Cenozoic Era. Deposition is dominated by clastic sediments transported from continental highlands into the Gulf of Mexico basin for a period exceeding 50 million years. These sediments were transported to the coast by rivers and deposited in a variety of fluvial to marine depositional environments.

Structurally the Texas Gulf Coast consists of three regions, the Rio Grande Embayment, the San Marcos Arch, and the Houston Embayment. Other structural features found in the Texas Gulf Coast include the Stuart City and Sligo Shelf Margins, and the Wilcox, Frio, and Vicksburg Fault Zones.

The San Marcos Arch is a broad gently sloping positive structural feature extending from the Llano Uplift in Central Texas to the Gulf Coast during the Ouachita Orogeny. The Rio Grande and Houston Embayment's are thought to have resulted from subsidence induced by high rates of sedimentation (Dodge and Posey, 1981).

The Tertiary sediments deposited in the Rio Grande and Houston Embayment's are characterized by deltaic sands and shales. High rates of clastic deposition resulted in the formation of normal listric growth faults. Constant sediment loading and coastal subsidence into the basin led to the accumulation of over 50,000 feet of Cenozoic strata into the Gulf Coast Basin.

Jurassic salt and younger shale diapirs are also present in the subsurface along the Gulf Coastal Plain. The displacement of shale and salt is generated by the accumulation of an excessive thickness of overburden sediment causing plastic flow of the more ductile sediments. The resulting structures may cause local faulting and/or dip reversal along with the formation of domes and anticlinal structures.

Within the South Texas Uranium Province, uranium mineralization occurs primarily in the Cenozoic sediments of the Miocene/Pliocene Goliad Formation, Miocene Oakville Formation, Oligocene/Miocene Catahoula Formation, and the Eocene Jackson Group. Project deposits occur in the Goliad Formation which is a major fluvial system that represents a low to moderate energy environment composed of isolated mixed-load channel-fill sands separated by thick inter-channel clays.

Uranium deposits are roll-fronts, typical to others found in the South Texas Uranium Province. Deposit genesis is related to the presence of highly reduced groundwater systems generated from the biogenic decomposition of natural gas and/or hydrogen sulfide seepage derived from deeper formations through localized faulting. At Alta Mesa, uranium bearing groundwater moved from northwest to southeast within the Goliad Formation and encountered reduction zones associated with the Vicksburg fault system and the Alta Mesa salt dome and associated faulting which allowed the introduction of organics and other fluids upward through faults and fractures.

The deposits are characterized by numerous vertically stacked roll-fronts controlled by stratigraphic heterogeneity, host lithology, permeability, reductant type and concentration, and groundwater geochemistry. Individual roll-fronts are a few tens of feet wide, 4 to 10 feet thick, and often thousands of feet long. Collectively, roll-fronts result in an overall deposit that is up to a few hundred feet wide, 50 to 75 feet thick and continuous for miles in length.

History

In the early 1970's through June of 1985, Chevron Minerals held Project mineral leases. In 1985, Chevron allowed leases to expire reverting rights back to landowners.

From July 1988 to 1993, total minerals held the mineral the leases. Total engaged URI to complete a feasibility study of the project. In 1993, Total relinquished mineral leases to Cogema under directive from the French government.

From 1993 to 1996, Cogema held the Alta Mesa mineral leases, but once relinquished were acquired by URI. URI held the mineral leases from 1996 to 1998, and during their tenure obtained the Radioactive Material License.

In 1999, Mesteña Uranium LLC was formed by the landowners. Mesteña completed most of the drilling on the project and began construction of the ISR facility in 2004. Production began in the fourth quarter of 2005 and Mesteña operated the facility through February 2013. Due to downturn in the uranium market, in 2013 the project was put into care and maintenance standby.

Mesteña acquired the adjacent Mesteña Grande projects in 2006 through the execution of the Uranium Testing Permit and Lease Option to explore on mineral rights outside of the existing Uranium In-Situ Mining Lease with the expectation that additional mineralized uranium resources could provide future feed for the Project.

On June 17, 2016, Energy Fuels acquired the Project, including both the Alta Mesa and Mesteña Grande projects.

In November 2022, enCore entered into a Membership Interest Purchase Agreement dated November 14, 2022, with EFR White Canyon Corp., a subsidiary of Energy Fuels, to acquire four limited liability companies that together hold 100% of the Project. Acquisition cost was US$120 million USD payable in a combination of cash and vendor take-back convertible note secured against the assets.

In February 2024, the Company entered a joint venture with Boss to develop and advance the Project. enCore retains ownership of 70% of the project and Boss holds 30%. Prior to 2023, all drilling was considered historical. Initial drilling at the Alta Mesa portion of the project was done by Chevron between 1981 and 1984 when they drilled approximately 360 holes. These holes included exploration, some coring and well completions. Minor drilling and monitor well installation were also completed by Total Metals and Cogema. Most of the drilling was completed by MULLC between 1999 and 2013. From these drill programs, drill data is available for a total of 10,744 drill holes in the Alta Mesa portion of the project of which 5,620 drill holes were considered barren. Of the remaining 5,124 drill holes approximately 3,000 are within the existing wellfields. However, many of the drill holes within the wellfield have mineralized intercepts in sands that were not mined either above or below the mining units. Wellfields PAA-1 through PAA-3 were mined within the Goliad middle C sand. Wellfield PAA-5 was mined within the B sand and wellfields PAA-4 and PAA-6 are within the lower C sand. In addition, data is available for 460 drill holes in the Mesteña Grande portion of the Project.

Uranium was first discovered in Texas via airborne radiometric surveys in 1954 along the northern boundary of the South Texas Uranium Province where host formations outcrop. These initial discoveries led to the development of numerous conventional open pit mines. Subsequent exploration primarily, by drilling, extended mineralization down dip from the outcrop. At Alta Mesa, oil and gas drilling had been ongoing since the 1930's. The Alta Mesa deposits were discovered by Chevron in the mid 1970s while evaluating oil and gas geophysical logs for natural gamma signatures. From 1981 to 1984, Chevron drilled approximately 360 holes, collected core and completed some wells.

Total and Cogema conducted small drilling programs and installed some monitor wells. Most of the Project drilling was completed by Mesteña between 1999 and 2013.

Mesteña developed six wellfields or production areas, identified as PAA-1 through PAA-6. All production was from the Goliad; however, from different formation sands. PAA-1 through PAA-3 were mined within the Goliad middle C-Sand. PAA-5 was mined within the B-Sand and wellfields PAA-4 and PAA-6 are within the lower C-Sand. Many of the wellfield drill holes intersected mineralization in sands above or below the wellfields indicating additional mineral resource potential. Approximately, 3,000 holes are drilled within the wellfields.

Between 2005 and 2013, approximately 4.6 M lbs of uranium were produced by ISR mining. Maximum annual production achieved was 1.07 million pounds. Average annual production was 0.57 million pounds. The facility was in production from 2005 until February 2013, when the project was placed in care and maintenance due to unfavorable market conditions.

Permitting and Licensing

The most significant permits and licenses required to operate the Project are (1) the Source and Byproduct Materials License, which was issued by TCEQ (formerly Texas Bureau of Radiation Control) in 2002; (2) the Mine Area Permit issued by TCEQ in April 2000; and (3) Production Area Authorizations (UIC Class III) issued at various times since April 2000, two deep injection non-hazardous disposal wells (V wells) issued by TCEQ in April 2000 and an aquifer exemption issued by USEPA in 2002 and the area was expanded in a revised Aquifer Emption dated 2009. Similar permits would be required for the Mesteña Grande project area depending upon the nature of operations and their integration with the Alta Mesa facility.

PAA-1 has been mined, and the groundwater restoration has been approved by the TCEQ. PAA-2 through PAA-6 is either in standby or in the process of groundwater restoration. PAA-7 is currently being mined.

The status of the various federal and state permits and licenses are summarized in the table below

Permitting Status

Permit/License	Status
FCC - Radio License FRN0020106654	Active
Sewage System OSSF	Active
PAA-1	Active
PAA-2	Active
PAA-3	Active
PAA-4	Active
PAA-5	Active

PAA-6	Active
PAA-7	Active
Uranium Exploration Permit 125	Active
Radioactive Material License - R05360	Timely Renewal
L05939 - Sealed Source RML for PFN	Active
TCEQ Aquifer Exemption	Active
EPA Aquifer Exemption	Active
UIC Class III Mine Area Permit UR03060	Timely Renewal
USCOE 404 exemption SWG-1998-02466	Active
UIC Class I disposal well permit WDW-365	Active
UIC Class I disposal well permit WDW-366	Active

Quality Assurance and Quality Control

enCore maintains written standard operating procedures for drilling, lithological logging and geophysical logging. Virtually all drilling completed by enCore for the purposes of exploring and resource development consists of rotary drilling. enCore collected rotary mud samples for lithological logging by 5-foot increments. Lithological logs of the samples are completed in the field by geologists following the standard written procedures and using standard lithological log forms.

Drill hole locations are staked in the field using a Trimble hand-held GPS capable of sub-meter accuracy. The holes are surveyed prior to drilling. Field surveys of 8 exploration drill holes and one well with the Alta Mesa GPS unit as a check. The well location was within 0.13 feet of the recorded location. The drill hole locations deviated from the reported location by 1.33 to 11.28 feet with an average variance of 6.06 feet. It is this author's conclusion that the majority of the variance is due to the driller not accurately locating the drill hole at the staked location rather than the accuracy of the GPS unit, and thus, recommends that the drill hole location procedure be modified to include both pre and post drilling surveys of the drill holes.

Past drilling practices were conducted in accordance with industry standard procedures and the most recent drilling conducted by enCore, confirmed historical drill results in previously intersected mineralization for thickness, grade and location.

Sample Preparation, Analysis, and Security

Sample Methods

Samples are collected from drill holes for drill cuttings, down hole geophysics and core samples. Cores are the only samples that are prepared and dispatched to an analytical or testing laboratory. Cuttings and geophysical data are prepared and analyzed in house. Sampling, sample preparation and security are described in the following sections.

Down Hole Geophysical Data

Continuous measurement of down hole geophysical properties is measured from total hole depth to surface. Geophysical data is collected using logging probes equipped with gamma, resistivity, SP, PFN and down hole survey logging tools. This suite of logs is ideal for defining lithologic units in the subsurface. The resistivity and spontaneous potential tools are used to define lithology by qualitative measurements of water conductivities.

The gamma tool provides an indirect measurement of uranium content. Gamma radiation is measured in one-tenth foot intervals and converted to gamma ray readings measured in counts-per-second into %-eU_3O_8. Equivalent percent uranium grades are reported in one-half foot increments.

The PFN tool provides a direct measurement of uranium around the borehole. The pulsed neutrons sources electronically generate neutrons which causes fission of U^{235} in the formation. Tool detectors count epithermal and thermal neutrons returning from the formation providing a direct measurement of formation uranium content.

Drill holes are also down hole surveyed measuring deviation by azimuth and declination, providing a holes true bottom location and depth.

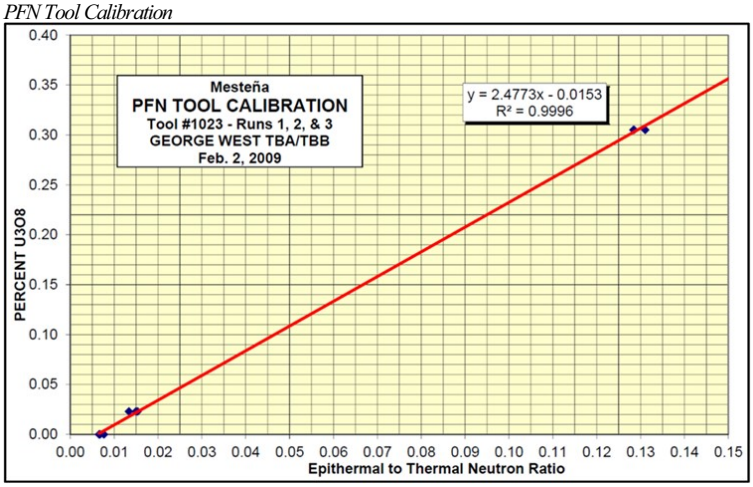
enCore samples all drill holes with gamma, resistivity, spontaneous potential and down hole survey. Due to cost and time, enCore only PFN samples mineralized intervals with gamma measured grades above 0.02 %-eU_3O_8.

To ensure geophysical data quality control, tools are calibrated at a US Department of Energy test pit in George West, Texas. PFN tools are calibrated using onsite test pits. Test pit have known uranium source concentration and using industry calibration procedures tools are calibrated, to ensure consistent measurement and reporting of uranium concentrations from US deposits.

PFN Calibration

The table below reflects a typical calibration curve for the PFN tool.

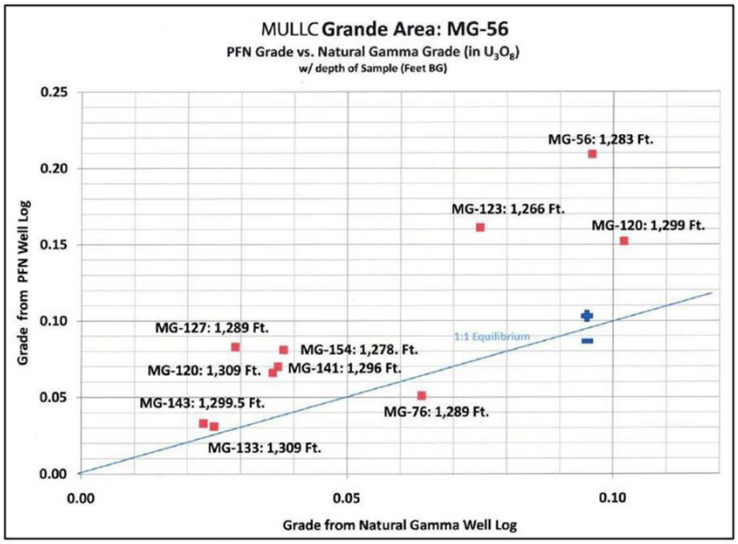
PFN Tool Calibration



Disequilibrium

Radioactive isotopes decay until they reach a stable non-radioactive state; the radioactive decay chain isotopes are referred to as daughters. When all the decay products are maintained in close association with the primary uranium isotope U238 for the order of a million years or more, the daughter isotopes will be in equilibrium with the parent isotope (McKay et.al., 2007). Disequilibrium occurs when one or more decay products are dispersed because of differences in solubility between uranium and its daughters. Disequilibrium is considered positive when there is a higher proportion of uranium present compared to daughters and negative where daughters accumulate, and uranium is depleted. The disequilibrium factor (DEF) is determined by comparing radiometric equivalent uranium grade eU_3O_8 to chemical uranium grade. Radiometric equilibrium is represented by a DEF of 1, positive DEF by a factor greater than 1, and negative DEF by a factor of less than 1. Total Minerals Incorporated applied a positive DEF of 1.13 to their Mineral Resource estimation (Total, 1989). Whereas Mesteña relied on PFN log data for determination of uranium grade and this method is a direct measurement of uranium content not equivalent radiometric assay, assessment of DEF is not applicable in this case where 92.8% of the data is PFN assay. The table below shows a disequilibrium graph comparing natural gamma U_3O_8 equivalent grades with PFN assays.

Disequilibrium Graph: Natural Gamma vs. PFN Grade



Drill Cuttings

Drill cuttings are collected at 5-foot intervals while drilling. Samples are arranged on the ground in order of depth to show changes in lithology and color. Lithology and color are recorded on a lithology log for entire hole depth. Particular attention is paid to color in the mineralized sand to assess oxidation/reduction potential. Cuttings are not chemically assayed as drilling mud will contaminate samples and precise sample location or depth cannot be determined from cuttings.

Core Samples

Core samples are collected to conduct chemical analyses, metallurgical testing, and testing of physical parameters of lithologic units. Retrieved cores are measured to determine core recovery. Cores are also washed, photographed and described. In preparation for laboratory analysis, to maintain moisture content and prevent oxidation, core is wrapped in plastic, boxed and frozen or iced.

Laboratory Analysis

When core is collected in the field, it is immediately rinsed, measured for length, split in half and photographed. One half of the core is sampled in 1-foot increments and either wrapped in plastic or vacuum sealed to maintain moisture content and prevent oxidation, boxed, frozen or iced and transferred to an analytical or testing laboratory.

The other half of core is split into quarters. One quarter is preserved as previously described, and the other quarter is used to describe lithologic characteristics (i.e., lithology, color, grain size and fraction).

Core preserved for testing is used for leach amenability determination. Leach amenability studies are intended to demonstrate that the uranium mineralization is capable of being leached and determination of the optimal mining lixiviant chemistry. Typically, sodium bicarbonate is used as the source for a carbonate complexing agent to form uranyldicarbonate (UDC) or uranyltricarbonate ion (UTC), and Oxygen or Hydrogen peroxide are used as the uranium-oxidizing agent. Tests are not designed to approximate in-situ conditions (permeability, porosity, pressure) but are an indication of an ore's reaction rate and potential uranium recovery.

enCore adheres to security measures using Chain of Custody procedures to ensure the validity and integrity of samples through the analysis process. enCore may sample and transfer duplicate samples to assess reliability and precision of analytical results for quality control of sample collection or laboratory analysis procedures.

Core samples are submitted to an analytical or testing laboratory that is certified through the National Environmental Laboratory Accreditation Program, which establishes and promotes mutually acceptable performance standards for the operation of environmental laboratories. The standards address analytical testing, with State and Federal agencies and serve as accrediting authorities with coordination facilitated by the EPA to assure uniformity.

Opinion on Adequacy

It is the opinion of the QP to the Alta Mesa Technical Report Summary, that enCore's sample preparation, methods of analysis, and sample and data security procedures adhere to acceptable industry standard procedures.

With respect to historical sample preparation, analysis and security of other previous operators, this information is not available and cannot be confirmed.

It is the opinion of this QP that there are no known sampling preparation, analysis and security factors that could materially affect the accuracy and reliability of results.

Data Verification

The QP visited the site on January 7, 2025, to inspect the site and verify data in the technical report.

The previous owner/operator, Mesteña Uranium LLC, who conducted most of the drilling on the project had written procedures for the collection of drill data including lithological logging, natural gamma logging, and PFN logging, and for the entry of said data into the Geographic Information System (GIS) based master database.

Data Confirmation

To verify data, the following steps were taken by the QP to review:

- SOP's for drilling procedures, lithological and geophysical logging, and coring,
- Drilling, lithological and geophysical logging in the field,
- Geologists' interpretation of lithology comparing drill cuttings to resistivity and SP geophysical results,
- Raw downhole geophysical data, grade calculations from raw data, and compositing method used to calculate average mineral grade and determine thickness,
- Geologists' interpretation of deposit characteristics from gamma and PFN downhole geophysical data,
- Historic core information,
- Workflow and data management including collection, processing, interpretation, digital documentation and database storage; and,
- Geophysical calibration records.

Limitations

Coring was not observed in the field as no coring activities were conducted during the duration of the site visit; however, the data for previously collected and sampled core was reviewed.

Data Adequacy

A considerable amount of work has been done by enCore and previous operators to ensure an adequate data set exists for the Project. It is the QP's opinion that the data used in this technical report is adequate for technical reporting.

Based on data quality, efforts of others, and the QP's review, it is the opinion of the QP that there are no known data factors that will materially affect the accuracy and reliability of results.

Mineral Extraction Activities

Mineral Resources

The following table shows the extraction history from the beginning of extraction activities in June 2024 to December 31, 2024 from the South Texas Integrated ISR Project:

Project	2024
Alta Mesa ISR Project	
Pounds U_3O_8 (000)	190,000

Mineral resources that are not mineral reserves have no demonstrated economic viability and do not meet the requirement for all the relevant modifying factors. Stated mineral resources are derived from estimated quantities of mineralized material recoverable by ISR methods.

Key Assumptions, Parameters and Methods

Key Assumptions

- Mineral resources have been estimated based on the use of the ISR extraction method and yellowcake production,
- Price forecast, production costs and an 80% metallurgical recovery were used to estimate mineral resources.
- Average wellfield recovery of 80% that accounts for dilution from mining hydro logic efficiency and metallurgical recovery,
- Average plant recovery of 98%; and,
- Average uranium price of $83.43 based on TradeTech's Uranium Market Study 2023: Issue 4.

Key Parameters

- The mineral resources estimates are based on data collected from drill holes,
- Grades (% U_3O_8) were obtained from gamma radiometric probing of drill holes and checked against assay results to account for disequilibrium,
- Average density of 17.0 cubic feet per ton was used, based on historical sample measurements,
- Minimum grade to define mineralized intervals is 0.020% eU_3O_8,
- Minimum mineralized interval thickness is 1.0 feet,
- Minimum GT (Grade x Thickness) cut-off per hole per mineralized interval for grade-thickness contour modeling is 0.30 feet% U_3O_8,
- Mineralized interval with GT values below the 0.30 feet% U_3O_8 GT cut-off is used for model definition but are not included within the mineral resource estimation,
- Average annual production rate of approximately 0.4 million pounds,
- Average annual estimated operating costs of $27.44 per pound,
- Average annual estimated wellfield development costs of $11.33 per pound; and,
- Average annual restoration and reclamation costs of $2.94 per pound.

Key Methods

- Geological interpretation of the orebody was done on section and plan from surface drill hole information,
- The orebody was modeled creating roll-front outlines for each of the deposit's individual mineralized zones,
- Pre-wellfield development, mineral resources within the roll-front outlines were estimated by grade-thickness averaging, where the variable of uranium grade is multiplied by interval thickness and averaged within the roll-front outline,
- Post-wellfield development, mineral resources within the roll-front outlines were estimated by grade-thickness contouring, where the variable of uranium grade is multiplied by interval thickness and contoured area,
- Wellfield recovery, lixiviant uranium head grades, wellfield flow rates and production requirements were used to define production sequencing; and,
- Geological modeling and mining applications used was ArcGIS Pro.

Resource Classification

Mineral resources are disclosed as required by United States Code of Federal Regulations, Title 17, Chapter II, Part 229, §229.1303 and §229.1304, and are based upon and accurately reflect information and supporting documentation prepared by the QP, as defined in §229.1300.

The following classification criteria for each mineral resource category are applied for alignment with §229.1300 definitions of Measured, Indicated and Inferred mineral resources.

Measured Mineral Resources

Drilling is denser than 50 x 200 feet spacing for mineralized zones characterized by a uniform and easily correlatable roll-front morphology, from one drilling fence line to another. Mineralization must be continuous between drill fences. The hydrogeological properties of the hosting horizon are studied by aquifer pump tests. The amenability of mineralization to ISR mining is demonstrated by laboratory leach tests. Mineralization is characterized by sufficient confidence in geological interpretation to support detailed wellfield planning and development with no or very little changes expected from additional drilling.

Indicated Mineral Resources

Drilling density equivalent to or denser than 50 x 200 feet spacing for mineralized zones characterized by a uniform and easily correlatable roll-front morphology, from one drilling fence line to another. Mineralization must be continuous between drill fences. The hydrogeological properties of the hosting horizon are studied by aquifer pump tests. The amenability of mineralization to ISR mining is demonstrated by laboratory leach tests. Mineralization is characterized by sufficient confidence in geological interpretation to support wellfield planning and development with some changes expected from additional drilling.

Inferred Mineral Resources

Drilling density equivalent to about 800 feet spacing for mineralized zones characterized by less uniformity and not easily correlatable roll-front morphology, from one drilling fence line to another. Mineralization must be continuous between drill fences but there is less confidence in geologic interpretation. The hydrogeological properties of the hosting horizon are studied by aquifer pump tests. The amenability of mineralization to ISR mining is demonstrated by laboratory leach tests. Mineralization is characterized by insufficient confidence in geological interpretation to support wellfield planning and development due to significant changes expected from additional drilling.

Mineral Resource Estimates

A summary of the Project's mineral resource estimates is provided in the table below.

Summary of Uranium Mineral Resources at the Alta Mesa ISR Project as of December 31, 2024
(Based on a metal price of $83.43/lb. U_3O_8)

Category	Tons (x 1,000)	Avg Grade (%) U_3O_8	Total Lbs (x 1000) U_3O_8
Measured	263.7	0.136	691.4
Indicated	630.0	0.150	1,894.5
Total Measured and Indicated	**894.0**	**0.145**	**2,585.9**
Inferred	2,223.4	0.112	5,200.5
Total Inferred	**2,223.4**	**0.112**	**5,200.5**

Notes:
1 enCore reports mineral reserves and mineral resources separately. Reported mineral resources do not include mineral reserves.
2 The geological model used is based on geological interpretations on section and plan derived from surface drill hole information.
3 Mineral resources have been estimated using a minimum grade-thickness cut-off of 0.30 ft% U_3O_8.
4 Mineral resources are estimated based on the use of ISR for mineral extraction.
5 Inferred mineral resources are estimated with a level of sampling sufficient to determine geological continuity but less confidence in grade and geological interpretation such that inferred resources cannot be converted to mineral reserves.

Mining, Processing and Recovery Methods

Mining Method

enCore is mining uranium using ISR. An alkaline leach system of carbon dioxide and oxygen is used as the extracting solution. Bicarbonate, resulting from the addition of carbon dioxide to the extracting solution, is the complexing agent. Oxygen is added to oxidize the uranium to a soluble +6 valence state.

ISR has been successfully used for over five decades in the United States as well as in other countries such as Kazakhstan and Australia. ISR mining was developed independently in the 1970s in the former USSR and U.S. for extracting uranium from sandstone hosted uranium deposits that were not suitable for open pit or underground mining. Many sandstones host deposits that are amenable to ISR, which is now a well-established mining method. As discussed in Section 5.0, Alta Mesa

is an operating mine that was in production from 2005 to 2013, with resumption of production in 2024, demonstrates that uranium can be mobilized and recovered with an oxygenated carbonate lixiviant.

Mine Designs and Plans

Production and injection wells are installed to facilitate the in-situ mining process. Injection wells are used to inject chemically fortified natural groundwater into the ore body liberating uranium. Production wells are used to recover the uranium rich waters by pumping the production fluid to the surface. Wells are completed in only one mineralized zone at a time and in a manner that focuses fluid flow across the deposit.

The fundamental production unit for design and production planning or scheduling is the pattern. A pattern is comprised of a production well and some number of injection wells.

Typical well patterns used are alternating single line drive, staggered line drive and five-spot. Pattern configuration is determined by the size and shape of the deposit, hydrogeological properties of the uranium bearing formation and mining economics.

Patterns are grouped into production units referred to as wellfields or modules. Modules form a practical means for design, development and production, where groups of 10-15 production wells and their associated injections wells are designed, constructed and operated, serving as the fundamental operating unit for distribution of the alkaline leach system.

To further facilitate planning, wellfields are grouped into PAAs. PAAs represent a collection of wellfields for which baseline data, monitoring requirements, and restoration criteria have been established. This data is included in the Production Area Authorization Application that is submitted to the TCEQ for approval prior to injection into a new mine unit.

An economic wellfield must cover the construction costs associated with well installation, connection of wells to piping that conveys the leach system between wellfields and the processing plant, and wellfield and plant operating costs.

To establish baseline data, monitoring requirements and restoration criteria, baseline production zone and non-production zone monitor wells are installed for each mine unit.

Baseline monitor wells are completed in the wellfield within the deposit hosting sandstone to establish baseline water restoration criteria of the wellfield production zone. Perimeter monitor wells are installed in a ring around the entire wellfield. This ring is setback approximately 400 feet from the patterns and 400 feet apart. This monitor well ring will be used to ensure mining fluids are contained within the wellfield.

Monitor wells will also be completed in non-production zone hydro-stratigraphic units above (overlying) and, if required below (underlying), the production zone to monitor the potential for vertical lixiviant migration. These monitor wells will be completed in the first overlying aquifer. In the event a second overlying aquifer is identified, the thickness and integrity of the intervening aquitard will be evaluated to determine if the second aquifer will require monitoring.

Each injection and production well will be connected within a network of polyethylene pipe to an injection or production manifold. Manifolds are fitted with meters, valves, and pressure gauges to measure and regulate flow to and from the wells. The manifolds are connected to larger trunk line pipes that convey fluids to and from the wellfield and CPP.

Since the climate is mild with winter temperatures rarely below freezing for prolonged periods of time, the production and injection pipelines and manifolds are not required to be buried below the ground. In colder climates ISR wellfields also need structures to house the manifolds and associated valves and instrumentation to prevent them from freezing. This expense is not necessary in south Texas. The ability to use surface piping reduces wellfield capital costs and reclamation costs.

Uranium is produced in wellfields by the dissolution of water-soluble uranium minerals from the deposit using a lixiviant at near neutral pH ranges. The lixiviant contains dissolved oxygen and carbon dioxide. The addition of carbon dioxide increases the bicarbonate level; however, the natural bicarbonate in the ground is generally high enough that additional CO_2 is not needed. The oxygen oxidizes the uranium, which is then complexed with the bicarbonate. The uranium-rich solution is then pumped from the production wells to the CPP for uranium concentration with ion exchange (IX) resin. A slightly greater volume of water is recovered from the hydro-stratigraphic unit than is injected, referred to as “bleed”, to create an

inward flow gradient towards the wellfields. Thus, overall production flow rates will always be slightly greater than overall injection rates. This bleed solution is disposed, as permitted, via injection into Class I DDW's.

Production Rates and Expected Mine Life

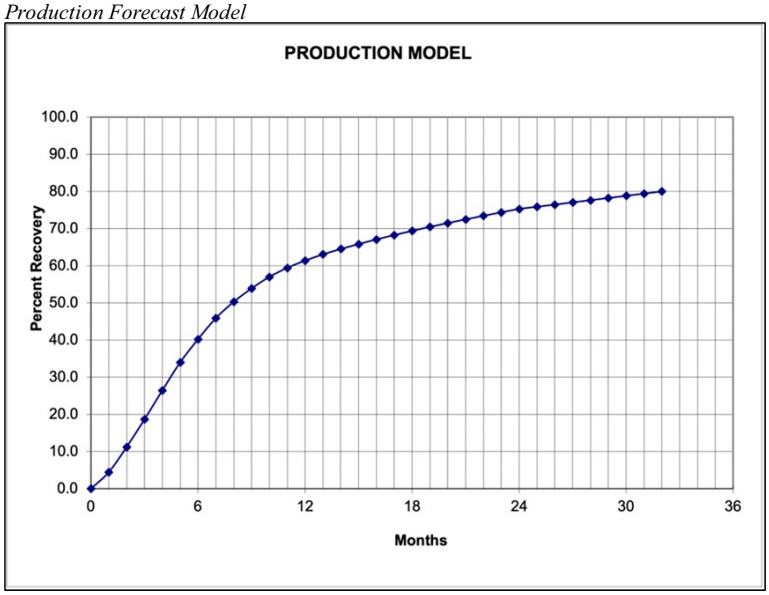
Flow rate and head grades will be maintained to achieve annual production rate. New wellfields will be developed and commissioned at a rate to ensure adequate head grades are maintained as operating wellfields are depleted to achieve production objectives.

Production rate was calculated using a production model as shown below. The production model was applied to mineral resources using the following parameters:

- Average recovery well flow rate of 45 gpm
- Maximum CPP flow rate of 7,500 gpm
- Average feed grade of 60 ppm U_3O_8
- 80% mineral recovery in 32 months

For 2024, the Alta Mesa the Project's wellfield solution head grades peaked at approximately 140 mg/L U_3O_8 and averaged approximately 65 mg/L U_3O_8.

Production Forecast Model



Mine Construction

In February 2023, enCore completed the acquisition of the Project from Energy Fuels, Inc establishing ownership of a second south Texas uranium processing plant. In March, the company announced its formal decision to resume commercial operations in early 2024 and commenced pre-construction and drilling activities preparing staging areas, drill pads and identification of equipment requiring maintenance or repair.

From March 2023 to Q2 2024, enCore renovated the CPP with equipment upgrades and refurbishments to the IX, elution and yellowcake processing circuits. During this timeframe, enCore also advanced mine development. The Project includes existing and new near-term production areas such as PAA-6 and PAA-7, which are fully permitted. Development is progressing in PAA-7, and brownfield drilling is being conducted in PAA-8, PAA-9 and PAA-10.

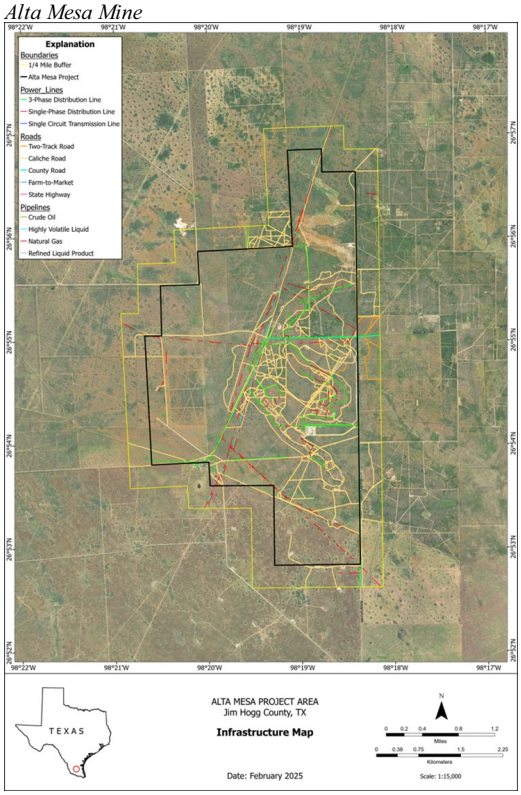
In PAA-7, 943 holes were drilled of which 224 were deemed suitable for further development into injection and production wells. In PAAs 8 through 10, 161 holes were drilled targeting mineralization in multiple horizons.

enCore commenced mining operations in PAA-7 in June 2024 and plans to ramp up production with a progressive process to advance and continually increase output. The plant has an operating flow capacity of 7,500 gpm. A new wellfield will be brought online on a near quarterly basis until the CPP name plate flow rate is achieved. The CPP has a design capacity of 2.0 million pounds U_3O_8 per year for IX elution, precipitation, slurry filtration, drying and packaging. The CPP has an IX uranium recovery capacity of 1.5 million pounds U_3O_8 per year through three separate IX circuits.

Flow rate and head grades will be maintained to achieve annual production rate. New wellfields will be developed and commissioned at a rate to ensure adequate head grades are maintained as operating wellfields are depleted to achieve production objectives.

Texas does not set a license capacity. It is determined by MILDOS estimates that were done in 2008, assuming 2 million pounds per year. We can change that without needing an amendments. The IX circuits have demonstrated the ability to capture and elute about 500,000 pounds per year.

Alta Mesa Mine



Processing and Recovery

The CPP collects and processes uranium. The CPP processing circuits consists of IX, elution, precipitation, dewatering, drying and packaging. Part of enCore's operational plan is to mine uranium from satellite properties processing product at one of the company's CPPs.

In February 2024, enCore submitted the License R05360 Renewal and Amendment Application to the TCEQ requesting amendment to the existing license activities authorization to construct and operate remote ion exchange (RIX) facilities within the existing license area and to process resin for uranium extraction that is generated from other sources. RIX are self-contained stand-alone processing facilities with an IX circuit and a resin transfer system. RIX is the same uranium recovery process as IX in the CPP. Once uranium is recovered, loaded resin will be transferred via the resin transfer system and trucked to the CPP.

Ion Exchange

Uranium is recovered from pregnant lixiviant solution using the IX circuit. The IX circuit consists of three independent parallel process streams of four up-flow columns each that are operated in series. Each IX circuit has a 2,500 gallons per minute operational capacity for a total IX operational capacity of 7,500 gallons per minute. Each IX circuit has four (4) up flow IX columns each containing 500 cubic foot batch of anionic ion exchange resin to capture uranium from the pregnant lixiviant. The circuit does have a secondary downflow IX processing circuit downstream of the up-flow circuits to capture any residual uranium from the up-flow columns effluent. Production and Injection booster pumps are located upstream and downstream of the trains, respectively.

Vessels are designed to provide optimum contact time between pregnant lixiviant and IX resin. An interior stainless-steel piping manifold system distributes lixiviant evenly across the resin. The dissolved uranium in the pregnant lixiviant is

chemically adsorbed onto the ion exchange resin. The resultant barren lixiviant exiting the vessels contains less than 2 ppm of uranium and is returned to the wellfield where oxygen and carbon dioxide are added prior to reinjection.

Bleed

A bleed is drawn from the injection stream prior to reinjection into the wellfield to maintain control of hydraulic conditions in the production zone. Bleed water is directed into the liquid waste stream and disposed of.

Elution Circuit

Loaded resin in the up-flow columns is eluted in-situ stripping uranium from the resin with a brine solution and forming a uranium rich eluate. The uranium rich eluate overflows from the up-flow columns and is then pumped to eluant tanks.

Precipitation Circuit

Uranium rich eluate is transferred to a precipitation circuit. Sulfuric acid is added to the uranium rich eluate lowering the pH to the range of 2 to 3 where the uranyl carbonate breaks down, liberating carbon dioxide and leaving free uranyl ions. Next, sodium hydroxide (caustic soda) is added to raise the pH to the range of 4 to 5. After this pH adjustment, hydrogen peroxide is added in a batch process to form an insoluble uranyl peroxide ($UO_2O_2{\cdot}H_2O$) compound. After precipitation, the pH is raised to approximately 7 and the uranium precipitated slurry is pumped to a filter press. The barren solution is disposed of via a deep injection well.

Filtering, Drying and Packaging

After precipitation, yellowcake is removed for washing, filtering, drying and product packaging in a separate building at the CPP. The yellowcake from the filter press is washed to remove excess chlorides and other soluble contaminants. The filter cake is transferred via progressive cavity pump to a yellowcake hopper and then to the yellowcake dryer.

The CPP is equipped with two rotary low temperature vacuum dryers. The yellowcake is dried at temperature ranging from approximately 176 to 212 °F. The dryer is an enclosed unit and heated by circulating propane heated oil through an external jacket. Drying time per batch typically ranges between 9 to 14 hours. The off gases generated during the drying cycle, which are primarily water vapor, are filtered through a bag house to remove entrained particulates and then condensed. Compared to conventional high temperature drying by multi-hearth systems, this dryer has no significant airborne particulate emissions.

The dried yellowcake is packaged into 55-gallon drums for storage before transport by truck to a conversion facility.

The yellowcake drying and packaging stations are segregated within the processing plant for worker safety. Dust abatement and filtration equipment is deployed in this area of the facility. Filled yellowcake drums are stored on a curbed concrete pad until transport.

Water Balance

The water balance is based on a production maximum flow rate of 7,500 gpm and a 1% bleed to maintain hydraulic control of the mine units. In the CPP water will be used for make-up and washdown at a rate of approximately 12 gpm from a local fresh water supply well. Restoration activities will include 250 gpm feed to an RO, with 175 gpm returned to the wellfield and 75 gpm to a liquid effluent management system that includes the use of six above ground 44,000-gallon storage tanks and water injection into permitted Class I injection wells.

Liquid Waste Disposal

The Project uses deep disposal wells for disposal of liquid waste generated during production and restoration. Alta Mesa has two disposal wells that are permitted under TCEQ's Underground Injection Control Class I permit program.

Solid Waste Disposal

Waste classified as non-contaminated (non-hazardous, non-radiological) will be disposed of in the nearest permitted sanitary waste disposal facility. Waste classified as hazardous (non-radiological) will be segregated and disposed of at the nearest permitted hazardous waste facility. Radiologically contaminated solid wastes that cannot be decontaminated, are

classified as 11.e.(2) byproduct material. This waste will be packaged and stored on-site temporarily and periodically shipped to a licensed 11.e.(2) byproduct waste facility or a licensed mill tailings facility.

Major Components	Cost US$000s (No Sales Tax)
Plant Refurbishments	$2,500
Wellfields	$23,400
Total	**$25,900**

Economic Analysis

The Alta Mesa Project economic analysis illustrates a cash flow forecast on an annual basis using Mineral Resources and an annual extraction schedule for the LOM NPV. A summary of taxes, royalties, and other interests, as applicable to extraction and revenue are also discussed, as well as the impact of significant parameters such as uranium sales price, and capital and operating costs to economic sensitivity. The analysis assumes no escalation, no debt, no debt interest, no capital repayment and no state income tax since Texas does not impose a corporate income tax.

enCore is using a uranium sales price ranging from $82.00 to $89.00 with an average sales price of $83.43.

The economic analysis assumes that 80% of the mineral resources and mineral reserves are recoverable. The pre-tax net cash flow incorporates estimated sales revenue from recoverable uranium, less costs for surface and mineral royalties, property tax in the form of ad valorem, plant and wellfield operations, product transaction, administrative and technical support, D&D, and restoration. The after-tax analysis includes the above information plus depreciated plant and wellfield capital costs, to estimate federal income tax.

Less federal tax, the Projects cash flow is estimated at $83.8 million or $42.89 per pound U_3O_8. Using an 8% discount rate, the Projects NPV is $63.4 M. The Projects after tax cash flow is estimated at $64.9 M for a cost per pound U_3O_8 of $52.03. Using an 8.0% discount rate, the Project's NPV is $51.6 million.

Economic Analysis Forecast by Year with Exclusion of Federal Income Tax

Cash Flow Line Items	Units	Total or Average $ per Pound		2025	2026	2027	2028	2029
Uranium Production as U_3O_8[1,2]	Lbs 000s	2,068	-	313	351	400	314	406
Uranium Price for U_3O_8[3]	US$/lb	83.4	0.0	84.3	83.8	83.3	82	84
Uranium Gross Revenue	US$000s	$172,536	-	$26,369	$29,390	$33,306	25,736	33,885
Less: Surface & Mineral Royalties	US$000s	$5,400	$2.61	$825	$920	$1,042	806	1,061
Taxable Revenue	US$000s	$167,135	-	$25,543	$28,470	$32,264	24,930	32,825
Less: Property Tax	US$000s	$617	$0.30	$48	$49	$65	96	67
Net Gross Sales	US$000s	$166,518	-	$25,495	$28,421	$32,199	24,834	32,758
Less: Plant & Wellfield Operating Costs	US$000s	$38,955	$18.84	$5,979	$6,386	$6,912	5,988	6,974
Less: Product Transaction Costs	US$000s	$1,209	$0.58	$183	$205	$234	183	237
Less: Administrative Support Costs	US$000s	$10,519	$5.09	$1,504	$1,504	$1,504	2,002	2,002
Less: D&D and Restoration Costs	US$000s	$6,070	$2.94	$0	$0	$0	-	346
Net Operating Cash Flow	US$000s	$109,765	-	$17,829	$20,326	$23,548	16,660	23,198
Less: Plant Development Costs	US$000s	$2,500	$1.21	$2,500	$0	$0	-	-
Less: Wellfield Development Costs	US$000s	$23,431	$11.33	$3,546	$3,976	$4,533	3,556	4,598
Net Before-Tax Cash Flow	US$000s	$83,834	-	$11,783	$16,350	$19,015	13,105	18,600

Taxes, Royalties and Other Interests

Federal Income Tax

Total federal income tax for LOM is estimated at $18.9 M for a cost per pound U_3O_8 of $9.13. Federal income tax estimates do account for depreciation of plant and wellfield capital costs.

State Income Tax

The state of Texas does not impose a corporate income tax.

Production Taxes

Production taxes in Texas include property tax in the form of ad valorem tax. The Projects personal property (i.e., uranium facilities, buildings, machinery and equipment) are subject to property tax by the following taxing jurisdictions: Brooks County, Brooks County Roads & Bridges, Brooks County Independent School District, Brooks County Farm to Market & Flood Control Fund and Brush Country Groundwater Conservation District.

In 2024, Alta Mesa personal property was valued at $1.4 million and subject to the following tax rates resulted in 2024, property tax of $0.03 million.

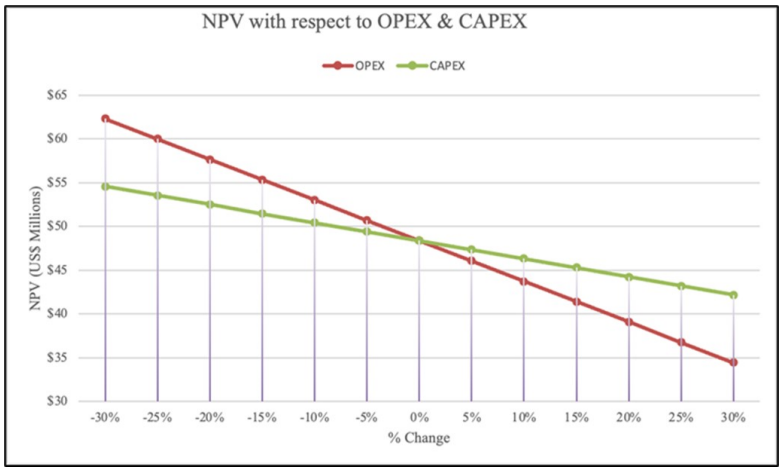
Taxing Jurisdiction	Tax Rate	Market Value	Estimated Tax
Brooks County	0.792191	$1,351,720	$10,708
Brooks County Rd & Bridges	0.069828		$943.88
Brooks County ISD	1.323800		$17,894
Brooks CO FM & FC	0.038828		$524.85
Brush County Groundwater Conservation District	0.010791		$145.86
	2.24		$30,216

Royalties

Royalties are assessed on gross proceeds. The project is subject to a cumulative 3.0% surface and mineral royalty at an average LOM sales price of $83.43 per lb. U_3O_8 for $5.4 M or $2.61 per pound.

NPV v. Uranium Price

This analysis is based on a variable commodity price per pound of U_3O_8 and the cash flow results. The Project is most sensitive to changes in the price of uranium. A $5.0 change in the price of uranium can have an impact to the NPV of more than $8.0 million at a discount rate of 8%.



Sensitivity Analysis

Project economics are sensitive to changes in price of uranium, capital and operating costs. At an average sales price of $83.43 and discount rate of 8%, a $5.0 change in the price of uranium can have an impact to the NPV of more than $8.0

million. Whereas a 5% change in operating and capital costs can have an impact to the NPV of approximately $2.0 and $1.0 million, respectively.

Planned Work

For 2025, the Company intends to conduct the following work at the Alta Mesa Project:

- Continue uranium extraction in the Phase 1 area of PAA 7.
- Start uranium extraction and expand wellfield capacity for Phase 2 to feed the 2nd IX circuit at the Alta Mesa CPP (West Plant)
- Install monitor wells for PAA 8.
- Conduct exploration drilling for the LC South and the D sand inferred resource areas.

Mesteña Grande Uranium Project, Brooks and Jim Hogg Cos, Texas

The Mesteña Grande Project is an ISR uranium project located in south Texas. The Project lies within the southern part of the South Texas Uranium Province. Uranium deposits in the South Texas Uranium Province extend from Starr County at the international border with Mexico northeastward through Zapata, Jim Hogg, Brooks, Webb, Duval, Kleberg, McMullen, Live Oak, Bee, Atascosa, Karnes, Wilson, Goliad, and Gonzales counties.

Part of enCore's operational plan is to mine uranium from satellite properties processing IX resin at one of the company's CPPs. At the Alta Mesa Project, enCore has an active mine and CPP. Portions of the Project are located adjacent to the south and to the north of the Alta Mesa Project, with other parts located as much as 50 miles northwest of the CPP. enCore plans to develop and advance the Project and process uranium at Alta Mesa.



The following technical and scientific description of the Mesteña Grande Project is based in part on the report titled "Mesteña Grande Uranium Project, Brooks and Jim Hogg Counties, Texas, USA, S-K 1300 Technical Report Summary" dated February 19, 2025, and effective December 31, 2024, and prepared by SOLA Project Services, LLC, a Qualified Person and independent of the Company (the "Mesteña Grande Technical Report Summary"). The Mesteña Grande Technical Report Summary was prepared in accordance with S-K 1300. The Mesteña Grande Project does not have known "Mineral Reserves" and is therefore considered under SEC S-K 1300 definitions to be an Exploration Stage Property.

Property Description and Location

The Mesteña Grande Project properties include multiple project areas, including Mesteña Grande North (MGN), Mesteña Grande Central (MGC), Mesteña Grande South (MGS) Mesteña Grande Alta Vista (MGAV), Mesteña Grande El Sordo (MGES), Mesteña Grande North Alta Mesa (MGNAM) and Mesteña Grande South Alta Mesa (MGSAM) project areas. The properties collectively total 194,119 acres. The northwest corner of the Project is adjacent to and extends for about 36 miles north-northwest of the Alta Mesa CPP from Brooks County into Jim Hogg County, Texas. The project extents cover approximately 30 miles in an east-west direction, and approximately 35 miles in a north-south direction.

Ownership

Mineral ownership in Texas is private estate. Private title to all land in Texas emanates from a grant by the sovereign of the soil (successively, Spain, Mexico, the Republic of Texas, and the state of Texas). By a provision of the Texas Constitution, the state released to the owner of the soil all mines and mineral substances therein. Under the Relinquishment Act of 1919, as subsequently amended, the surface owner is made the agent of the state for the leasing of such lands, and both the surface owner and the state receive a fractional interest in the proceeds of the leasing and production of minerals.

The Jones Ranch holdings include private surface and mineral rights for oil and gas and other minerals, including uranium.

Uranium recovered at the Mesteña Grande Project will be processed at the Alta Mesa CPP under the current Uranium Solution Mining Lease, as described above under the property description for the Alta Mesa Project.

Accessibility

The Project is accessible year-round from two primary locations: 1) a ranch gate located approximately 5 miles east of Hebbronville, Texas along State Highway 285 (paved); and 2) a ranch gate located approximately 19 miles south of Hebbronville along Farm to Market Road 1017 (paved), as well as from the adjacent the Alta Mesa Project. The Alta Mesa Project location is approximately 11 miles west of the intersection of US Highway 281 (paved) and North Farm to Market Road 755 (paved), 22 miles south of Falfurrias, Texas.

Infrastructure

The Project is well supported by nearby towns and services. Larger cities, Corpus Christi, McAllen and Laredo, are each about 100 miles or less from the site and are ready sources of materials and equipment. Major power lines are located across the Project and are accessed for electrical service. The road system is comprehensive and well maintained and used for shipment of materials and equipment.

Human resources are employed from nearby population centers. Numerous local communities provide sources for labor, housing, offices and basic supplies. enCore utilizes local resources when and where possible supporting the local economy.

The site has uranium drill holes and related infrastructure (e.g., small mud pits temporarily constructed to facilitate drill operations and water supply ponds), and trucks and other equipment. Because of the Project's proximity to Alta Mesa, Alta Mesa does serve as a base of operation for, administration, shop and warehouse, environmental support, and logging services.

Water supply for the Project is from established and permitted local wells. Solid waste is disposed off-site at licensed disposal facilities. No tailings or other related waste disposal facilities are needed.

Geology, Mineralization and Deposit

The Texas Gulf Coast comprises the western flank of the Gulf of Mexico sedimentary basin with active deposition throughout the mid to late Mesozoic Era and into the Cenozoic Era. Deposition is dominated by clastic sediments

transported from continental highlands into the Gulf of Mexico basin for a period exceeding 50 million years. These sediments were transported to the coast by rivers and deposited in a variety of fluvial to marine depositional environments.

Structurally the Texas Gulf Coast consists of three regions, the Rio Grande Embayment, the San Marcos Arch, and the Houston Embayment. Other structural features found in the Texas Gulf Coast include the Stuart City and Sligo Shelf Margins, and the Wilcox, Frio, and Vicksburg Fault Zones.

The San Marcos Arch is a broad gently sloping positive structural feature extending from the Llano Uplift in Central Texas to the Gulf Coast during the Ouachita Orogeny. The Rio Grande and Houston Embayment's are thought to have resulted from subsidence induced by high rates of sedimentation (Dodge and Posey, 1981).

The Tertiary sediments deposited in the Rio Grande and Houston Embayment's are characterized by deltaic sands and shales. High rates of clastic deposition resulted in the formation of normal listric growth faults. Constant sediment loading and coastal subsidence into the basin led to the accumulation of over 50,000 feet of Cenozoic strata into the Gulf Coast Basin.

Jurassic salt and younger shale diapirs are also present in the subsurface along the Gulf Coastal Plain. The displacement of shale and salt is generated by the accumulation of an excessive thickness of overburden sediment causing plastic flow of the more ductile sediments. The resulting structures may cause local faulting and/or dip reversal along with the formation of domes and anticlinal structures.

Within the South Texas Uranium Province, uranium mineralization occurs primarily in the Cenozoic sediments of the Miocene/Pliocene Goliad Formation, Miocene Oakville Formation, Oligocene/Miocene Catahoula Formation, and the Eocene Jackson Group. Project deposits occur in the Goliad Formation which is a major fluvial system that represents a low to moderate energy environment composed of isolated mixed-load channel-fill sands separated by thick inter-channel clays.

Uranium deposits are roll-fronts, typical to others found in the South Texas Uranium Province. Deposit genesis is related to the presence of highly reduced groundwater systems generated from the biogenic decomposition of natural gas and/or hydrogen sulfide seepage derived from deeper formations through localized faulting. At Alta Mesa, uranium bearing groundwater moved from northwest to southeast within the Goliad Formation and encountered reduction zones associated with the Vicksburg fault system and the Alta Mesa salt dome and associated faulting which allowed the introduction of organics and other fluids upward through faults and fractures. At Mesteña Grande, uranium mineralization occurs in numerous locations within the Goliad, Oakville, and Catahoula Formations and is formed in much the same way as at Alta Mesa. Uranium bearing groundwater within each of these formations encountered reduction within the groundwater associated with major growth fault systems within the region.

The deposits at Mesteña Grande are characterized by vertically stacked roll-fronts controlled by stratigraphic heterogeneity, host lithology, permeability, reductant type and concentration, and groundwater geochemistry. Individual known roll-fronts may be few tens of feet wide, 2 to 10 feet thick, and often thousands of feet long. Collectively, roll-fronts are inferred to result in an overall deposit that is up to a few hundred feet wide, 50 to 75 feet thick and continuous for miles in length

History

In 1999, Mesteña Uranium LLC was formed by the landowners. Mesteña completed most of the drilling on the adjacent Alta Mesa project and began construction of the Alta Mesa ISR facility in 2004. Production began in the fourth quarter of 2005 and Mesteña operated the facility through February 2013. Due to a downturn in the uranium market, in 2013 the project was put into care and maintenance standby.

Mesteña Uranium, LLC acquired the Mesteña Grande projects in 2006 as an exploration option to provide additional uranium feed to the Alta Mesa plant.

On June 17, 2016, Energy Fuels acquired the Project, including both the Alta Mesa and Mesteña Grande projects. In November 2022, enCore entered into a Membership Interest Purchase Agreement dated November 14, 2022, with EFR White Canyon Corp., a subsidiary of Energy Fuels, to acquire four limited liability companies that together hold 100% of the Project. Acquisition cost were $120 million USD payable in a combination of cash and vendor take-back convertible note secured against the assets.

In February, the Company entered a joint venture with Boss Energy, Ltd. to develop and advance the Project. enCore retains ownership of 70% of the project and Boss Energy holds 30%. See the discussion above under the description of the Alta Mesa Project for more information regarding the joint venture with Boss.

Licensing and Permitting

The Project is not permitted or licensed to operate with the exception of the permits necessary for exploration.

The most significant permits and licenses that will be required to operate the Project are (1) the TCEQ Source and Byproduct Materials License, (2) the Mine Area Permit issued by TCEQ and (3) Production Area Authorizations (UIC Class III) that are issued at various times through LOM, deep injection non-hazardous disposal wells (V wells) issued by TCEQ, and an USEPA aquifer exemption.

The timing to prepare the applications and for agency review and approval is estimated to be 3 to 4 years. The length of time is not entirely in enCore's control. The TCEQ's ability to process enCore's applications is dependent on the workload of the agency. With the renewed interest in uranium recovery, the application process timeline could be longer due to additional requests for ISR permits and licenses.

The costs to obtain these licenses and permits is estimated to be $2.87 million. These costs include environmental baseline sampling of the air, water (surface and subsurface), soils, and vegetation in the vicinity of the proposed activities. The background radionuclide concentrations in the environment will also be determined. For the UIC Class III permits monitor wells will be installed and sampled to establish baseline water quality prior to mining.

Quality Assurance and Quality Control

Quality Assurance and Quality Control at the Mesteña Grande Project are identical to those for the adjacent Alta Mesa Project and are disclosed above under the description of the Alta Mesa Project.

Since enCore's acquisition of the Mesteña Grande Project, there has been no sampling of natural materials for the assessment of geologic or hydrologic conditions that require preparation, analysis and security to submit samples to a laboratory; however, enCore does have sample preparation, methods of analysis, and sample and data security procedures that meet acceptable industry standards.

With respect to historical sample preparation, analysis and security of other previous operators, this information was not available and cannot be confirmed.

It is the opinion of the QP for the Mesteña Grande Technical Report Summary that there are no known sampling preparation, analysis and security factors that when used will materially affect the accuracy and reliability of results.

Data Verification

Data verification procedures at the Mesteña Grande Project are identical to those for the adjacent Alta Mesa Project and are disclosed above under the description of the Alta Mesa Project.

Based on data quality, efforts of others, and the QP's review, it is the opinion of the QP for the Mesteña Grande Technical Report Summary that there are no known data factors that will materially affect the accuracy and reliability of results.

Mineral Resources

Key assumptions for the following Mineral Resource estimates are as follows:

- Mineral resources have been estimated based on the use of the ISR extraction method and yellowcake production,
- Price forecast, production costs and an average wellfield recovery of 60% that accounts for dilution from mining hydrologic efficiency and metallurgical recovery, were used to estimate mineral resources,
- Average plant recovery of 98 %; and
- Average LOM uranium price of $85.48 based on TradeTech's Uranium Market Study 2023: Issue 4.

Key parameters for the following Mineral Resource estimates are as follows:

- The mineral resources estimates are based on data collected from drillholes,

- Grades (% U_3O_8) were obtained from gamma radiometric probing of drillholes and checked against assay results to account for disequilibrium,
- Average density of 17.0 cubic feet per ton was used, based on historical sample measurements,
- Minimum grade to define mineralized intervals is 0.020% eU_3O_8,
- Minimum mineralized interval thickness is 1.0 feet,
- Minimum GT (Grade x Thickness) cut-off per hole per mineralized interval for grade thickness contour modeling is 0.30ft % U_3O_8,
- Mineralized interval with GT values below the 0.30ft %U_3O_8 GT cut-off is used for model definition but are not included within the mineral resource estimation,
- Average annual production rate of approximately 1.2 pounds,
- Average annual estimated operating costs of $25.49 per pound ,
- Average annual estimated wellfield development costs of $11.33 per pound; and,
- Average annual restoration and reclamation costs of $2.94 per pound.

Key Methods for the following Minderal Resources estimates are as follows:

- Geological interpretation of the orebody was done on section and plan from surface drill hole information,
- The orebody was modeled creating roll-front outlines for each of the deposit's individual mineralized zones; and,
- Geological modeling and mining applications used was ArcGIS Pro.

Resource Classification

Mineral resources are disclosed as required by United States Code of Federal Regulations, Title 17, Chapter II, Part 229, §229.1303 and §229.1304, and are based upon and accurately reflect information and supporting documentation prepared by the QP, as defined in §229.1300.

The following classification criteria for each mineral resource category are applied for alignment with §229.1300 definitions of Measured, Indicated and Inferred mineral resources.

Measured Mineral Resources

Drilling is denser than 50x100 feet spacing for mineralized zones characterized by a uniform and easily correlatable roll-front morphology, from one drilling fence line to another. Mineralization must be continuous between drill fences. The hydrogeological properties of the hosting horizon are studied by aquifer pump tests. The amenability of mineralization to ISR mining is demonstrated by laboratory leach tests. Mineralization is characterized by sufficient confidence in geological interpretation to support detailed wellfield planning and development with no or very little changes expected from additional drilling.

Indicated Mineral Resources

Drilling density equivalent to or denser than 200x400 feet spacing for mineralized zones characterized by a uniform and easily correlatable roll-front morphology, from one drilling fence line to another. Mineralization must be continuous between drill fences. The hydrogeological properties of the hosting horizon are studied by aquifer pump tests. The amenability of mineralization to ISR mining is demonstrated by laboratory leach tests. Mineralization is characterized by sufficient confidence in geological interpretation to support wellfield planning and development with some changes expected from additional drilling.

Inferred Mineral Resources

Drilling density equivalent to about 800 feet spacing for mineralized zones characterized by less uniformity and not easily correlatable roll-front morphology, from one drilling fence line to another. Mineralization must be continuous between drill fences but there is less confidence in geologic interpretation. The hydrogeological properties of the hosting horizon are studied by aquifer pump tests. The amenability of mineralization to ISR mining is demonstrated by laboratory leach tests. Mineralization is characterized by insufficient confidence in geological interpretation to support wellfield planning and development due to significant changes expected from additional drilling.

Mineral Resource Estimates

Summary of Uranium Mineral Resources at the Mesteña Grande Uranium Project as of December 31, 2024.
Based on a metal price of $85.48/lb. U3O8

Category	Tons (x 1,000)	Avg Grade (%) U_3O_8	Total Lbs (x 1000) U_3O_8
Measured	-	-	-
Indicated	-	-	-
Total Measured and Indicated	**-**	**-**	**-**
Inferred	5,852.8	0.1	13,887.9
Total Inferred	**5,852.8**	**0.1**	**13,887.9**

Notes:

1. enCore reports mineral reserves and mineral resources separately. Reported mineral resources do not include mineral reserves.
2. The geological model used is based on geological interpretations on section and plan derived from surface drillhole information.
3. Mineral resources have been estimated using a minimum grade-thickness cut-off of 0.30 ft% U_3O_8.
4. Mineral resources are estimated based on the use of ISR for mineral extraction.
5. Inferred mineral resources are estimated with a level of sampling sufficient to determine geological continuity but less confidence in grade and geological interpretation such that inferred resources cannot be converted to mineral reserves.

Mining, Processing and Recovery Methods

enCore's operational plan is to mine uranium from satellite properties processing product at one of the company's CPPs. At the Alta Mesa Project, enCore operates an active mine and CPP and the Project is located about 30 miles northwest of the CPP. enCore plans to develop and advance the Project and process the RIX resin at Alta Mesa.

enCore plans to recover uranium using RIX. RIX are self-contained stand-alone processing facilities with an IX circuit and a resin transfer system. The process flow of the RIX is the same as the IX circuit in the CPP. Once uranium is recovered at the RIX, the loaded resin will be transferred via the resin transfer system to a resin trailer and trucked to the CPP for elution, precipitation, drying, and packaging. Figures 14.1 and 14.2 are the P&ID and general arrangement drawings for a modular 1,000 gpm RIX design that can be expanded by adding 1,000 gpm RIX modules. The RIXs at the Mesteña Grande will be larger to accommodate an increased flowrate. Infrastructure at the Alta Mesa Project will allow for processing of all RIX resin at the Alta Mesa CPP.

For a description of mining method, mine design and plans and processing at Alta Mesa, see the discussion above for the Alta Mesa Project.

Economic Analysis

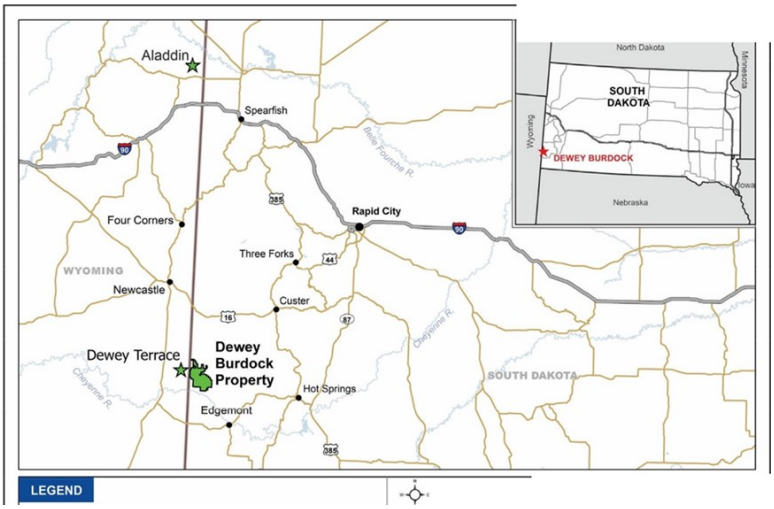
The Company does not consider the economic analysis in the Mesteña Grande Technical Report Summary to be material to the Company's operations at this time or to the Company's planned work for the Project in 2025.

Planned Work

For 2025, the Company intends to continue to conduct exploration drilling.

Dewey-Burdock Project, Fall River and Custer Counties, South Dakota

The Dewey Burdock Project is an Exploration Stage Property located in southwest South Dakota and forms part of the northwestern extension of the Edgemont Uranium Mining District (the "Dewey Burdock Project"). The Dewey Burdock Project includes federal claims, private mineral rights and private surface rights controlling the entire area within the licensed project permit boundary as well as surrounding areas. The Company currently controls approximately 16,962 acres of net mineral rights and 12,613 acres of surface rights. The net result of the royalty and rental payments results in a cumulative 4.85% surface and mineral royalty.



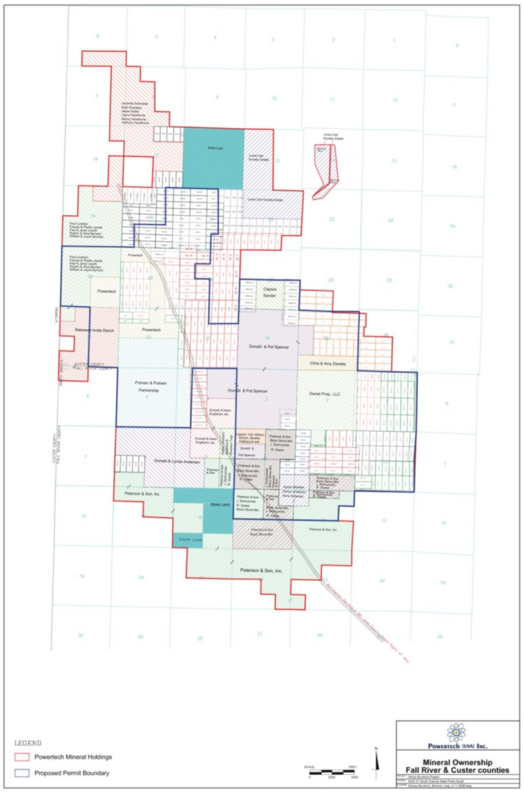
The following technical and scientific description of the Dewey-Burdock Project is based in part on the report titled "Dewey Burdock Project, South Dakota, USA, S-K 1300 Technical Report Summary" dated January 6, 2025, and effective October 8, 2024, and prepared by SOLA Project Services, LLC, a Qualified Person and independent of the Company (the "Dewey Burdock Technical Report Summary"). The Dewey Burdock Technical Report Summary was prepared in accordance with S-K 1300. The Dewey Burdock Project does not have known "Mineral Reserves" and is therefore considered under SEC S-K 1300 definitions to be an Exploration Stage Property.

Property Description and Location

The Project is in southwest South Dakota and forms part of the northwestern extension of the Edgemont Uranium Mining District. The project area is in Townships 6 and 7 South, Range 1 East, of the Black Hills Prime Meridian approximately 13 miles north-northwest of Edgemont. The county line dividing Custer and Fall River counties, South Dakota, lies at the confluence of Townships 6 and 7 South. The company holds approximately 16,962 acres of mineral rights in the area. The permitted area encompasses approximately 10,580 acres of mostly private land and 240 acres under the control of the BLM.

Ownership

Mineral titles are comprised of federal claims, private minerals and private surface rights within the permit boundary and surrounding areas. Access and mineral rights are currently held by a combination of private surface use agreements, access and mining lease agreements, purchase agreements and federal mineral claims. The Company currently holds 16,962 mineral acres with an annual cost of $401,307. These royalties for fee minerals range from 2% to 4% of gross sales.



Accessibility

The nearest population center to the Project is Edgemont, South Dakota (population 900) located on US Highway 18, 14 miles east from the Wyoming-South Dakota state line. Fall River County Road 6463 extends northwestward from Edgemont to the abandoned community of Burdock located in the southern portion of the Project, about 16 miles from Edgemont. This road is two-lane and all-weather gravel and continues north from Burdock to the Fall River-Custer County line where it becomes Custer County Road 769. The road closely follows the tracks of the Burlington Northern Santa Fe Railways "BNSF" between Edgemont and Newcastle, Wyoming. Dewey is about 2 miles from the northwest corner of the Project.

An unnamed unimproved public access road into the Black Hills National Forest intersects Fall River County Road 6463 4.3 miles southeast of Burdock and extends northward about 4 miles, allowing access to the east side of the Project. About 0.9 miles northwest from Burdock, an unimproved public access road to the west from Fall River County Road 6463 allows access to the western portion of the Project. Private ranch roads intersecting Fall River County Road 6463 and Custer County Road 769 allow access to all other portions of the Project.

Project access is granted by private surface leases, or public access on federal lands. There are no significant limitations to surface access and usage rights that will affect the company's ability to conduct exploration, development or operations. Since waste rock and tailing will not be generated there is no requirement for surface mine waste disposal and no requirement for acquiring surface rights for on-site disposal. All 11.e.(2) designated waste will be disposed of at an off-site licensed facility, all non 11.e.(2) waste will be disposed of at a local licensed landfill and liquid wastes will be disposed of using licensed lined impoundments and treated liquid effluents will be injected into a subsurface aquifer using permitted Class V injection wells.

Infrastructure

The Project is well supported by nearby towns and services. Major power lines are located across the Project and can be accessed for electrical service. The BNSF railroad crosses the Project, and a major railroad siding occurs at Edgemont and may be used for shipment of materials and equipment, if necessary.

Human resources will be employed from nearby population centers. The local communities of Edgemont, Custer and Hot Springs offer sources for labor, housing, offices and basic supplies. It is enCore's plan to utilize local resources when and where possible supporting the local economy.

Regarding site infrastructure, leases are written to have maximum flexibility for emplacement of tanks, out buildings, storage areas and pipelines. Most of the topography is relatively low lying and undulating and is conducive to development and operations.

The project site has no mining facilities or buildings. The only site equipment related to mining includes a weather monitoring station, radiological monitoring stations, and monitor wells. All are accessible by dirt roads.

Geology, Mineralization and Deposit

The Edgemont Uranium District is located on the southwest side of the Black Hills Uplift. The Black Hills Uplift is a Laramide Age structure forming a northwest trending dome about 125 miles long x 60 miles wide located in southwestern South Dakota and northeastern Wyoming.

The uplift has deformed all rocks in age from Cambrian to latest Cretaceous. Subsequent erosion has exposed these rock units dipping outward in successive elliptical outcrops surrounding the central Precambrian granite core. Differential weathering has resulted in present day topography of concentric ellipsoids of valleys under softer rocks and ridges held up by more competent units.

The Cretaceous sediments contain uranium roll front deposits in the more porous and permeable sands within the Inyan Kara Group, Lakota and Fall River Formations. The entire Inyan Kara Group consists of basal fluvial sediments grading into near marine sandstones, silts and clays deposited along the ancestral Black Hills Uplift. The sandstones are continuous along the entire western flank of the uplift and dip about 3 degrees to the southwest in the Project area.

The Lakota and Fall River Formations were deposited by northward flowing stream systems. Sediments are characterized by point bar and traverse bar deposition, in meandering fluvial systems. Sand units fine upward with numerous cut-and-fill indicative of channel migration depositing silt and clay upon older sand and additional channel sands overly older silts and clays. The Fall River sands are noticeably thinner with marine sediments superimposed directly on the fluvial sands.

The depositional characteristics of the Lakota and Fall River Formations results in stratigraphic heterogeneity within the sands. Because of this heterogeneity, uranium mineralization occurs as multiple sinuous roll fronts, instead of one large front as is observed in more homogeneous sands. Individual roll fronts are continuous and generally trend along strike but may or may not overlap. Individual roll fronts average about 8 feet thick and 30 feet wide. Where overlapping the deposit can be tens of feet thick and hundreds of feet wide. The strike length of individual roll fronts is variable but often on the order of thousands of feet, where the total strike length of the deposit is miles. Depth to mineralization is variable and ranges from about 180 to 920 feet.

History

Property ownership is often represented by split estate where separate parties own the rights to a surface parcel and the minerals beneath that parcel are owned by a different entity. Historically, when surface real estate was sold, property owners often retained mineral ownership resulting in the above-mentioned spilt estate. Other properties are split estate that were homesteaded under the 1916 Homestead Act granting homesteader surface ownership and the mineral rights were reserved by the U.S. Government.

Uranium minerals were discovered in the vicinity of the Project as early as 1952 and were soon mined by small mining companies using open pit, adit, or shallow underground mines. These mining companies leased the mineral rights from mineral or other claim owners. By the late 1950's, these deposits came under the control of Susquehanna who had purchased the process mill located in Edgemont. Susquehanna mined most of the known, shallow uranium deposits before closure of the mill in 1972.

During the uranium boom of the 1970s, several companies returned to the Project area, acquired leases and began exploration for deeper deposits. During this period, exploration companies such as Wyoming Mineral, Homestake Mining Company, Federal Resources and Susquehanna discovered deeper uranium roll-front type uranium mineralization. In 1978, TVA purchased Susquehanna's interest in the Edgemont Uranium Mining District, including the Edgemont mill. TVA made Dewey Burdock its main exploration target and developed enough reserves to warrant mine plans that included an underground mine shaft at both the Burdock and Dewey sites and a new uranium mill that was planned to be located near Burdock. TVA's plans ended when the price of uranium dropped in the early 1980's. Eventually, TVA dropped their leases and mining claims.

In 1994, Energy Fuels acquired the properties with an interest in exploration and development of the roll-front deposits. By 2000, Energy Fuels relinquished their land position in the Project. In 2005, Denver Uranium acquired federal claims and private mineral leases covering 11,180 acres and private surface rights covering 11,520 acres in the Project area. This acreage created a contiguous land position of both surface and mineral rights covering most of the discovered and delineated uranium in this district.

On February 21, 2006, Powertech and Denver Uranium entered into a binding Agreement of Purchase and Sale for the Project assets.

On October 29, 2014, Powertech merged with Azarga Resources Limited forming Azarga Uranium. To further consolidate project resources, Azarga entered into a binding property purchase agreement with Energy Metals on November 18, 2005, whereby Azarga acquired a 100% interest in 119 mineral claims covering approximately 2,300 acres.

In 2021, Azarga and enCore entered into an agreement whereby enCore was to purchase Azarga. In September of 2021, the acquisition was finalized with enCore acquiring multiple assets in various stages of development including the advanced stage Dewey Burdock Project.

Licensing and Permitting

The Project is the first uranium ISR facility to submit permit applications in the State of South Dakota. As such, there is inherent risk in a new permitting process, regulatory unfamiliarity with ISR methods, and an untested review period. The amount of time required for regulatory review of all permits associated with the commissioning of an ISR facility is highly variable and directly affects project economics. It is assumed enCore will have all permits necessary to construct in 2027. The timeframe to obtain licenses and permits is expected to be impacted by environmental NGO's and public contestation of both state and federal permits and licenses. Time for contested cases has been accounted for in the project development schedule.

The Project has drawn attention from environmental Non-Government Organizations "NGO's", tribal governments, and individuals in the public. enCore is managing this risk through the State and Federal permitting processes.

Extensive efforts by the regulatory agencies have proceeded to near completion of all major permitting and licensing actions.

The Nuclear Regulatory Commission "NRC" license (SUA 1600) was issued in 2014, challenged and appealed, is now in good standing and in timely renewal. The Environmental Protection Agency "EPA" issued the Class III and Class V Area Underground Injection Control "UIC" permits and Aquifer Exemption in 2020. The Class III and Class V UIC permits, and Aquifer Exemption were challenged by the OST and are under appeal.

The Environmental Appeals Board "EAB" heard oral arguments on the Class III and Class V UIC permits in March 2024. In September, the EAB issued its ruling on the Oglala Sioux Tribe "OST" appeal finding:

- The EAB 2023 decision denying OST claims and finding that EPA complied with the National Historic Preservation ACT "NHPA" Section 106,
- Denied OST claims and found that EPA complied with NHPA Section 110,
- Denied OST claims that EPA failed to comply with the National Environmental Protection Act "NEPA",
- Reserved judgment on other OST claims until EPA expands the administrative record adding documents, considers those additional materials, responds to related comments, takes further appropriate action in reissuing the permit decisions; and,

- The EAB remanded the reserved issues to EPA and specified that any appeals challenging the reissued permit decisions will be limited to the issues reserved in the remand and any modifications to the permits made as a result of the remand.

The EAB decisions regarding EPA compliance with NHPA and NAPA were favorable rulings and consistent with the 2023, D.C. Circuit Court of Appeals rulings where similar appeals were made by the OST against the NRC Source Material License.

Regarding the portion of the ruling remanded back to the EPA Region 8, it is anticipated that this will be an exercise to formally complete the administrative record. Once the administrative record is complete and the permit decision reissued, the EAB will consider any additional materials and respond to related comments. It is also anticipated that the OST will appeal the reissued permit, but the EAB will rule in favor of the EPA and enCore with minimal impact to the overall project schedule. If the EAB does find merit in the appealed reissued permit, there could be an impact to the project schedule.

A ruling on the issuance of the Aquifer Exemption is currently under appeal to the 8th Circuit Court of Appeals and will rule upon once the EAB issues final ruling on the Class III and Class V UIC permits.

In South Dakota, enCore is advancing work on the major state permits needed to operate the Project. The State Engineer had previously recommended approval of the Inyan Kara (#2686-2) and Madison (#2685-2) Water Rights. The next step to advance water rights will be the resumption of the Department of Agriculture and Natural Resources "DANR" Water Management Board hearings. Efforts are also advancing on the DANR Groundwater Discharge Plan and Large- Scale Permit to Mine approvals. The DANR has recommended conditional approval of the Groundwater Discharge Plan and Large-Scale Permit to Mine, pending completion of all federal challenges of the Class III, Class V and Aquifer Exemption.

Quality Assurance and Quality Control

Past drilling practices were conducted in accordance with industry standard procedures and the most recent drilling conducted by Powertech, confirmed historical drill results in previously intersected mineralization for thickness, grade and location. The QP of the Dewey Burdock Technical Report Summary is knowledgeable of the 2007 and 2008 work and technical participants who were responsible for the work.

Data Verification

Numerous companies have worked on the Project since the 1950's and as a result numerous data sets of different vintages exist. enCore has a nearly complete data set for the Project. The QP of this report has reviewed geophysical, core and hydrogeologic technical data. Technical data is stored in digital format for geologic interpretation and modeling. The QP has reviewed geologic interpretations and the resultant models, in the form of cross-sections, isopach and structural maps, and uranium roll front deposit models.

The work done by enCore and previous operators to verify historical records does validate Project information. Data are available for over 6,300 drill holes and for approximately 24% of the holes, enCore does not have the actual geophysical logs. The company does have collar location and mineralization data, for all holes, and has used data from surrounding holes to verify data for holes with missing geophysical logs. Considering drilling density, enCore's approach to data verification is a reasonable means to confirm data validity; however, not having data in hand does limit knowledge of precise location of down hole information.

Mineral Resources

Key assumptions for the following Mineral Resource estimates are as follows:

- Mineral resources have been estimated based on the use of the ISR extraction method and yellowcake production,
- Uranium price forecast is based on TradeTech's Uranium Market Study 2023: Issue 4,
- Price forecast, production costs and an 80% metallurgical recovery were used to estimate mineral resources.

Key parameters for the following Mineral Resource estimates are as follows:

- The mineral resources estimates are based on 6,394 drill holes,

- Grades (% U_3O_8) were obtained from gamma radiometric probing of drill holes and checked against assay results to account for disequilibrium,
- Average density of 16.0 cubic feet per ton was used, based on historical sample measurements,
- Minimum grade to define mineralized intervals is 0.020% eU_3O_8,
- Minimum mineralized interval thickness is 1.0 feet,
- Minimum GT (Grade x Thickness) cut-off per hole per mineralized interval for grade thickness contour modeling is 0.20ft % U_3O_8,
- Mineralized interval with GT values below the 0.20ft %U_3O_8 GT cut-off is used for model definition but are not included within the mineral resource estimation.

Summary of Uranium Mineral Resources at the Dewey-Burdock ISR Project as of December 31, 2024,
Based on a metal price of $87.05/lb. U_3O_8

ISR Resources	Measured	Indicated	M & I	Inferred
Lbs (U_3O_8)	14,285,988	2,836,159	17,122,147	712,624
Tons	5,419,779	1,968,443	7,388,222	645,546
Avg. GT	0.73	0.41	0.66	0.32
Avg. Grade (% U_3O_8)	0.13%	0.07%	0.12%	0.06%
Avg. Thickness (ft)	5.56	5.74	5.65	5.87

Notes:

1. enCore reports mineral reserves and mineral resources separately. Reported mineral resources do not include mineral reserves.
2. The geological model used is based on geological interpretations on section and plan derived from surface drill hole information.
3. Mineral resources have been estimated using a minimum grade-thickness cut-off of 0.20 ft% U3O8.
4. Mineral resources are estimated based on the use of ISR for mineral extraction.
5. Inferred mineral resources are estimated with a level of sampling sufficient to determine geological continuity but less confidence in grade and geological interpretation such that inferred resources cannot be converted to mineral reserves.

Mining, Processing and Recovery Methods

enCore will mine uranium using ISR. An alkaline leach system of carbon dioxide and oxygen will be used as the extracting solution. Bicarbonate, resulting from the addition of carbon dioxide to the extracting solution, will be used as the complexing agent. Oxygen will be added to oxidize the uranium to a soluble +6 valence state.

ISR has been successfully used for over five decades elsewhere in the United States as well as in other countries such as Kazakhstan and Australia. ISR mining was developed independently in the 1970s in the former USSR and U.S. for extracting uranium from sandstone hosted uranium deposits that were not suitable for open pit or underground mining. Many sandstones host deposits that are amenable to ISR, which is now a well-established mining method. As discussed in Section 13.0, bottle roll tests demonstrate that uranium can be mobilized and recovered with an oxygenate carbonate lixiviant.

A CPP and Satellite will collect and process uranium. The CPP processing circuits will consist of ion exchange, elution, precipitation, de-watering, drying and packaging. The Satellite facility will include an IX circuit and a resin transfer system to facilitate transfer of loaded resin by truck from the Satellite to the CPP. The processing method is an industry standard and proven method that is most suitable for uranium processing and recovery. The method also has low environmental impact and results in a high purity product.

The CPP will be located on the Burdock property and the Satellite will be located at Dewey. The distance between the two facilities is approximately four miles.

Economic Analysis

The Project economic analysis illustrates a cash flow forecast on an annual basis using mineral resources and an annual production schedule for the Life Of Mine Net Present Value "LOM NPV", Internal Rate of Return "IRR" and capital payback period. A summary of taxes, royalties, and other interests, as applicable to production and revenue are also discussed, as well as the impact of significant parameters such as uranium sales price, and capital and operating costs to economic sensitivity. The analysis assumes no escalation, no debt, no debt interest, no capital repayment and no state income tax since South Dakota does not impose a corporate income tax.

enCore is using a uranium sales price ranging from $82.00 to $89.00, with an average sales price of $86.34. The economic analysis assumes that 80% of the mineral resources are recoverable. The pre-tax net cash flow incorporates estimated sales revenue from recoverable uranium, less costs for surface and mineral royalties, severance and conservation tax, property tax, plant and wellfield operations, product transaction, administrative support, D&D, restoration, and pre-construction

capital. The after-tax analysis includes the above information plus amortized development costs, depreciated plant and wellfield capital costs, existing and forecasted operating losses to estimate federal income tax. Less Federal Tax, the Projects cash flow is estimated at $476.8 million or $52.56 per pound U_3O_8. Using an 8% discount rate, the Projects NPV is $180.1 million with an IRR of 39%. The Projects after tax cash flow is estimated at $363.4 million for a cost per pound U_3O_8 of $60.60. Using an 8.0% discount rate, the Projects NPV is $133.6 million and has an IRR of 33%.

Capital Cost Estimates

Estimated capital costs are $264.2 million and includes $2.2 million for pre-construction permitting and licensing costs, $178.0 million for wellfield development, $84.0 million for the CPP, Satellite and associated infrastructure. Labor costs for Wellfield Construction are also included in capital costs totaling $34.1 million.

Capital is heavily weighted from 2027 through 2029 with start-up costs for construction of the Burdock CPP, Dewey Satellite, initial Dewey and Burdock wellfields, and associated infrastructure. Capital costs during this period are estimated at $105.0 million.Operating Costs Estimates.

Operation Costs Estimates

Estimated operating costs for plant and wellfield operations, product transactions, administrative support, decontamination, and decommissioning, and restoration are presented in the table below.

Wellfield operating costs include electricity, replacement wells and associated equipment, header house repairs, rental equipment, rolling stock, equipment fuel and maintenance, and wellfield chemicals.

Plant operating expenses include plant chemicals, electricity, equipment fuel and maintenance, waste management operations, rentals and supplies, RO operations and product handling. Product transaction costs include costs for product shipping and conversion fees. Decontamination & Decommissioning "D&D" and restoration costs include costs for restoration of the wellfields, decontamination and decommissioning of facilities, and reclamation of the site.

Administrative support costs include legal fees, land and mineral acquisitions, regulatory fees, insurance, office supplies and financial assurance. Baseline, environmental monitoring and operational monitoring are included in Closure, Labor and plant operating costs.

Operating costs are estimated to be $23.81 per pound of U_3O_8. The basis for operating costs is planned development and production sequence and quantity, in conjunction with past production knowledge.

Labor costs associated with wellfield and plant operations, restoration and administration are included in operating costs.

Cash Flow Line Items	Units	Total or Average	$ per Pound
Uranium Production as U_3O_8[1,2]	Lbs 000s	**14,116**	-
Uranium Price for U_3O_8[3]	US$/lb	**$ 86.34**	-
Uranium Gross Revenue	**US$000s**	**$ 1,218,816**	-
Less: Surface & Mineral Royalties[4]	US$000s	**$ 70,935**	$ 5.03
Taxable Revenue	**US$000s**	**$ 1,147,881**	-
Less: Severance & Conservation Tax[5]	US$000s	**$ 54,410**	$ 3.85
Less: Property Tax[6]	US$000s	**$ 16,233**	$ 1.15
Net Gross Sales	**US$000s**	**$ 1,077,239**	-
Less: Plant & Wellfield Operating Costs	US$000s	**$ 276,856**	$ 19.61
Less: Product Transaction Costs	US$000s	**$ 4,636**	$ 0.33
Less: Administrative Support Costs	US$000s	**$ 23,632**	$ 1.67
Less: D&D and Restoration Costs	US$000s	**$ 30,955**	$ 2.19
Net Operating Cash Flow	**US$000s**	**$ 741,159**	-

Sensitivity Analysis

The analysis is based on a variable commodity price per pound of U_3O_8 and the cash flow results. The Project is most sensitive to changes in the price of uranium. A $5.0 change in the price of uranium can have an impact to the NPV of more than $29.0 million, and impact to the IRR of approximately 5% at a discount rate of 8%.

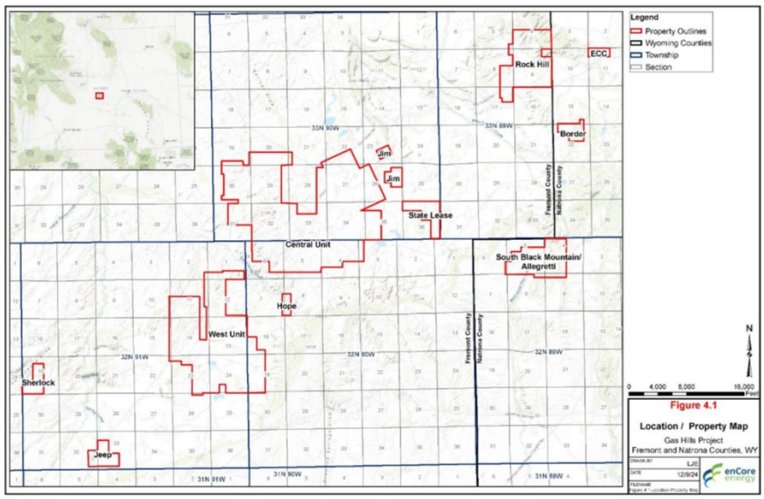
The Project NPV and IRR are also sensitive to changes in either capital or operating costs. A 5% change in the operating cost can have an impact to the NPV of approximately $6.5 million and the IRR of approximately 1% based on a discount rate of 8% and a uranium price of $86.34 per pound of U_3O_8. Using the same discount rate and sales price, a 5% change in the capital cost can have an impact to the NPV of approximately $7.1 million and the IRR of approximately 2.3%.

Planned Work

For 2025, the Company plans to complete significant permitting and license milestones, including the 10 year renewal of the Source Material License, SUA-1600, with the U.S. NRC, and the advancement of State approvals of its water rights application, large mine permit, and discharge permit.

Gas Hills Project, Natrona Co. and Fremont Counties, Wyoming

The Company owns a 100% interest in a project (the "Gas Hills Project") located in the historic Gas Hills uranium district situated 45 miles east of Riverton, Wyoming. The Gas Hills Project consists of approximately 1,280 surface acres and 12,960 net mineral acres of unpatented lode mining claims, a State of Wyoming mineral lease, and private mineral leases, within a brownfield site which has experienced extensive development including mine and mill site production.



The following technical and scientific description of the Gas Hills Project is based in part on the report titled "*Preliminary E*conomic Assessment, Gas Hills Uranium Project, Fremont and Natrona Counties, Wyoming, USA" dated February 5, 2025 and effective December 31, 2024, and prepared by Christopher McDowell, P.G. and Ray Moores, P.E., employed by WWC Engineering, each a Qualified Person and independent of the Company (the "Gas Hills Technical Report Summary"). The Gas Hills Technical Report Summary was prepared in accordance with S-K 1300. The Gas Hills Project does not have known "Mineral Reserves" and is therefore considered under SEC S-K 1300 definitions to be an Exploration Stage Property.

Property Description and Location

enCore's 100 percent owned Gas Hills Uranium Project is located approximately 45 miles east of Riverton, Wyoming in the historic Gas Hills Uranium District. The Project and the Gas Hills Uranium District are located along the southern extent of the Wind River Basin, near the northern edge of the Granite Mountains. The company's Project properties, including the West Unit, Central Unit, Rock Hill, South Black Mountain, and Jeep properties, consist of 628 unpatented lode mining claims, one State of Wyoming mineral lease, one private mineral lease, and one private surface use agreement.

Together the properties encompass approximately 360 surface acres and 12,960 mineral acres. The properties are located at latitude 42.7295°, longitude -107.6596° in Townships 32 and 33 North, Ranges 89, 90 and 91 West, 6th Principal Meridian, Fremont and Natrona Counties, Wyoming.

The U.S. federal government owns the minerals associated with the mining claims, the State of Wyoming owns the minerals and surface associated with the State lease, the South Pass Land and Livestock Company owns the minerals associated with the private mineral lease, and the Philp Sheep Company owns the surface associated with the private surface use agreement. The BLM manages the claims on behalf of the US federal government. The mining claims, State lease, and private mineral lease were assembled by Strathmore Resources (US) Ltd. (Strathmore) between April 2006 and September 2012 and sold to UColo on October 31, 2016. Title has remained in UColo's name since that date and UColo is a subsidiary of enCore. The surface use agreement was entered into by UColo effective July 7, 2023.

Ownership

On September 9, 2016, URZ's subsidiary, UColo, entered into an Asset Purchase and Sale Agreement (APA) with Strathmore, a wholly owned subsidiary of Energy Fuels, whereby URZ purchased all of Strathmore's interest in the Project. In addition to the Project, the APA transaction included URZ's purchase of Strathmore's claims and State mineral leases for the Juniper Ridge and Shirley Basin Properties, however, these two properties are not discussed in this Report. The transaction closed on October 31, 2016.

On May 7, 2018, Azarga and URZ announced an agreement to merge under a plan of arrangement. On June 29, 2018, the shareholders of both URZ and Azarga approved the merger and on July 5, 2018 the merger was completed. As a result, URZ became a wholly owned subsidiary of Azarga. On December 31, 2021, the shareholder approved merger of Azarga and enCore. The merger closed and Azarga became a wholly owned subsidiary of enCore. Approximately 12,560 mineral acres are encompassed by the Project claims. A 5% net proceeds royalty applies to 172 of the 628 claims as follows:

- A net proceeds royalty of 5% on 155 claims was granted by Quit Claim Deed from Strathmore to Elmhurst Financial Group, Inc. On October 31, 2007. One of the claims was relinquished during Strathmore's ownership. The surviving 154 claims were sold to UColo and remain subject to the 5% net proceeds royalty.
- A 5% net proceeds royalty was granted by Assignment from Strathmore to Blue Rock on October 31, 200, on nine full claims and on the southern 720 feet of nine additional claims. The 18 claims were sold to UColo and remain subject to the 5% net proceeds royalty.
- The other 456 claims are not subject to royalties or other encumbrances.

UColo has the possessory right to explore, develop and produce from the unpatented lode mining claim areas and must pay an annual maintenance fee to the BLM of $200.00 per claim on or before September 1 each year. Surface use at the location of the mining claims on BLM lands is allowed subject to Title 43 of the US Code of Federal Regulations Subpart 3809 and requires permitting by both the BLM and the State of Wyoming Department of Environmental Quality, Land Quality Division "WDEQ-LQD".

State of Wyoming Lease

Strathmore entered into a ten-year lease with the State of Wyoming for Mineral Lease #0-42121 on April 2, 2007. The lease was subsequently transferred by Assignment from Strathmore to UColo on October 31, 2016. UColo renewed the lease before its 10-year expiration, extending the lease an additional ten years to April 1, 2027. The lease can be renewed, at UColo's option, for unlimited additional 10-year periods as long as the terms and conditions of the lease have been met up to the time of applying to the State of Wyoming for renewal. The lease encompasses approximately 320 surface acres and 320 mineral acres in the NE¼, N½NW¼, and E½SE¼ of Section 36, Township 33 North, Range 90 West, 6th Principal Meridian, Fremont County, Wyoming. The lease grants to the State a royalty of 4 percent of the gross selling price of U_3O_8 or $5.00 per leased acre per year, whichever is more. No mineral resources in this Report are located on this lease.

Private Mineral Lease

Strathmore entered into a private mineral lease with South Pass Land and Livestock Company on July 28, 2010, for rights to minerals on the following two parcels of land: 40 mineral acres in the Jeep area in the SE¼ of Section 32, Township 32 North, Range 91 West, 6th Principal Meridian, Fremont County, Wyoming and 40 mineral acres in the West Unit area in the SW¼ of Section 19, Township 32 North, Range 90 West, 6th Principal Meridian, Fremont County, Wyoming. The mineral lease was transferred by Assignment and Assumption of Mineral Lease from Strathmore to UColo on October 31,

2016. UColo exercised its option to renew the lease for an additional 10 years in July 2020, by making the required payment. Unlimited 10-year renewals are available at UColo's option for additional payments. The lease grants a 5 percent net proceeds royalty to the owner of the mineral properties. The surface is owned separately from South Pass Land and Livestock Company. An agreement for surface access at the West Unit is described below. Presently, there is no agreement for surface access at the Jeep parcel.

Private Surface Use Agreement

UColo entered into a private surface use and access agreement with Philp Sheep Company on July 7, 2023, to access and use approximately 40 surface acres in the West Unit located in the SW1/4 of Section 19, Township 32 North, Range 90 West, 6th Principal Meridian, Fremont County, Wyoming. The agreement allows exploring, prospecting, drilling, constructing, and plugging and abandoning up to 10 exploratory boreholes on the parcel. Access to Section 19 is provided across the SW¼ of Section 13, Township 32 North, Range 91 West, 6th Principal Meridian, Fremont County, Wyoming under the agreement. The term of the agreement is through November 7, 2025. Philp Sheep Company does not own the minerals in the parcel covered by the agreement. The minerals are owned by the South Pass Land and Livestock Company described above.

Accessibility

The Gas Hills Uranium District can be accessed by traveling southeast of Riverton approximately 45 miles along Wyoming State Highway 136 (Gas Hills Road) to the junction of Fremont County Road #5 (Ore Haul Road).

Infrastructure

Extensive production in Wyoming of minerals (coal, trona, uranium) and oil/gas has provide a highly skilled labor force in the region. Population centers within two hours of the Project include Casper, Riverton, Lander, and Rawlins, where equipment and supplies may be obtained. Paved roads from these towns and cities extend to the edge of the Project area. Access and haul roads within the Project are graded gravel and are maintained by the State, County, and mining companies operating in the area. Functioning power lines, natural gas lines, telephone lines, and fiber optic cable are present on and near enCore's properties. Several wells producing water for domestic and industrial use are also on or close to enCore's properties. It is the Author's opinion that the Property area controlled by enCore is more than adequate to provide areas for potential mining operations and associated facilities and for mineral processing operations.

Geology, Mineralization and Deposit

In the Gas Hills district, lower Tertiary rocks unconformably overlie folded and faulted Mesozoic and older rocks (Figure 7.3). The Wind River Formation is conformably overlain by tuffaceous sandstones of the Eocene Wagon Bed Formation.

The Puddle Springs Arkose member of the Wind River Formation is the host rock for the uranium deposits at the Project. It consists of poorly consolidated arkosic sandstone and conglomerate with thin discontinuous interbeds of mudstone. The Puddle Springs arkose was deposited rapidly by northward-flowing braided streams to form coalescing piedmont alluvial fans (Soister, 1968).

The full thickness of the Wind River Formation is present from just north of the base of Beaver Rim Divide southward for a few miles. North of the contact between Wind River Formation and younger rocks, erosion has cut across the formation at a low angle and it progressively thins toward the north, where basal beds lie unconformably on older rocks.

The pre-Cenozoic strata in the Gas Hills are from Cambrian to Cretaceous in age. The Wind River Formation is the predominant rock outcrop at the Project, but Mesozoic and Tertiary formations also outcrop at the surface (Strathmore, 2013). The pre-Cenozoic rocks were extensively deformed during the Early Eocene faulting, uplift and basin development associated with the Laramide Orogeny. The pre-Cenozoic rocks are exposed sporadically throughout the Gas Hills. The area of greatest exposure is along the flanks of the Dutton Basin anticline. The anticline is exposed at the surface one mile east of the George-Ver Property; deposits from the Cody Shale downward to the Chugwater Formation outcrop (Beahm, 2017).

The uranium deposits are present in an arkosic sandstone facies of the Puddle Springs member of the Wind River formation (Strathmore, 2013). Drilling in the west Gas Hills indicates that the favorable arkosic sandstone grades into unfavorable silty facies. A local sandstone facies has been found within the silty facies, and a small area containing uranium (Jeep

deposit) has been found in the sandstone facies. Thus, the favorable host for mineralization in the above-mentioned deposits is bounded on the north by an erosional pinch out; on the east by a change of facies to an unfavorable silty sandstone host; on the south by a subsurface onlap pinch out; and on the west by change of facies to an unfavorable silty sandstone host.

Uranium mineralization in the Gas Hills is present in bodies usually referred to as "rolls" (King and Austin, 1966; Armstrong, 1970). In vertical cross section they are irregularly crescent or "C" shaped. Rolls are the result of oxidized and soluble uranium being transported by ground water to a location within a permeable sandstone host where a reaction within a reducing environment occurs and insoluble reduced, uranium minerals are deposited. The contact between oxidized and reduced conditions is the "roll front".

Uranium deposits in the Gas Hills were formed by the classic Wyoming-type roll-fronts. Roll-fronts are irregular in shape, roughly tabular and elongated, and range from thin pods and a few feet in width and length, to bodies several hundred or thousands of feet in length. The deposits are roughly parallel to the enclosing beds but may form rolls that cut across bedding. Roll-front deposits are typified by a C-shaped morphology in which the outside of the C extends down-gradient in the direction of historic groundwater flow and the tails extend up-gradient of historic groundwater flow. Tails are typically caught up in the finer sand and silt deposits that grade into over and underlying mudstones, whereas the heart of the roll-front (higher grade mineralization) lies within the more porous and permeable sandstones toward the middle of the fluvial deposits.

History

The Gas Hills Uranium District (Gas Hills) was one of the major uranium mining and production regions in the USA. Between 1953 and 1988, many companies explored, developed, and produced uranium in the Gas Hills, including on lands now controlled by enCore. Three uranium mills operated in the district and two others nearby were also fed by ore mined from Gas Hills. Cumulative production from the Gas Hills is in excess of 100 million pounds of uranium, mainly from open-pit mining, but also from underground mining and ISR.

Mine production did occur adjacent to and in the vicinity of the Project; however, the areas for which mineral resources are defined are unmined. Uranium was discovered in the Gas Hills in September 1953 by both ground and airborne radiometric surveys. Early exploration in the district exposed numerous near surface oxidized deposits and small shipments of ore were shipped out of state for processing. In 1955, the Atomic Energy Commission (AEC now the US DOE) constructed an ore buying station in Riverton, WY where ore was stockpiled and eventually milled. In the Gas Hills area, when the AEC approved purchase allotments in 1956, Utah Construction (later Pathfinder and then Areva) began the Lucky Mc Mill in the central Gas Hills and Lost Creek Oil and Uranium (later Western Nuclear) began the Split Rock Mill 15 miles south at Jeffrey City. By 1959 the AEC authorized three additional mills in the county: Fremont Minerals' (Susquehanna Mining) mill in Riverton, Federal-Radorock-Gas Hills Partners' (later Federal American Partners) central Gas Hills mill, and Globe Uranium Company's (later Union Carbide) east Gas Hills mill.

With the rapid decline in uranium price in the early to mid-1980's production slowly halted. The last mill production in the Gas Hills occurred in 1988, at Lucky Mc. Extensive mill site and mine reclamation occurred from the late 1980s through to the present time in the Gas Hills. However, Wyoming remains the largest current uranium producer in the USA and there are numerous uranium projects in the state (Beahm, 2017).

The present Project area was acquired by URZ's subsidiary UColo from Strathmore on October 31, 2016, and subsequently the Project area was acquired by enCore through a merger with Azarga in 2021. The minerals were originally acquired by staking and purchasing unpatented mining claims, and by acquiring the State of Wyoming Mineral Lease and the private South Pass Land and Livestock Company mineral lease.

More than 100,000 exploration and development holes were drilled in the Gas Hills from the mid-1950s to the mid-1980s. Since 1990, a few hundred holes have been drilled, nearly all by Strathmore and Cameco. Strathmore acquired exploration data for several of its Gas Hills properties; all of which are now controlled by enCore.

Permitting and Licensing

Prior to significant construction and mining, several permits/licenses from federal, state, and local agencies will be required as follows:

Federal
- EPA – Aquifer Exemption for UIC Class III wells and UIC Class I disposal wells (as necessary) and Subpart W Pond Construction Permit for the holding pond.
- BLM – Environmental Assessment (EA) and Approval of the Plan of Operations.

State
- Wyoming Department of Environmental Quality Uranium Recovery Program "WDEQ-URP" – Source and Byproduct Material License.
- WDEQ Land Quality Division "WDEQ-LQD" – Permit to Mine.
- WDEQ Water Quality Division "WDEQ-WQD" – UIC Class I Permit for deep well injection of wastewater generated from wellfield bleed and other plant processes, and Storm Water Discharge Permit which allows for surface discharge of storm water.
- WDEQ-Air Quality Division "WDEQ-AQD" – Air Quality Division, Chapter 6, Section 2, New Source Permit Authorization to Construct. • Wyoming State Engineer's Office "SEO" – Various groundwater appropriation permits for ISR of uranium.

Local
- Fremont County Septic system.

Since a large portion of the project lies over federal surface, the BLM will complete the National Environmental Protection Act "NEPA" analysis for this project which will be required to approve the BLM Plan of Operation. Since the footprint of this project is less than 640 acres, BLM regulations indicate that the NEPA analysis should be an Environmental Assessment "EA" level review. For the purposes of this PEA, it was assumed that the BLM would elect to do an EA level of analysis. Should BLM decide to pursue a full Environmental Impact Statement (EIS) a much more detailed analysis of potential project impacts will be required.

WDEQ-URP license preparation and review process will take approximately two years to complete. The review will include an opportunity for public comment. WDEQ-LQD, will review the permit to mine application pursuant to Noncoal Chapter 11 Rules and Regulations and will provide opportunities for public comment. The LQD review will also likely take about two years which will happen in parallel with the URP review. Following permit to mine approval, an aquifer exemption from the EPA Region 8 will be requested. The EPA will review the LQD's request against UIC Program requirements found in 40 CFR Parts 144 and 146 to ensure compliance. If the EPA determines the operation will be in compliance, the agency will issue an aquifer exemption which allows mining within a defined portion of the uranium host aquifer.

Quality Assurance and Quality Control

For 2011 and 2012, drilling security practices involved: awareness of chain-of-custody issues, limited access to logging tools through locked storage as approved by the U.S. Nuclear Regulatory Commission, and continuing calibration of logging tools to assure that no tampering has occurred. All drill hole samples were in locked storage until sent out for laboratory testing. Drill cutting samples were generally not preserved and it was typical for the mine operators to assay drill samples at their on-site laboratories.

Data Verification

Data sources reviewed for the estimation of uranium mineral resources for the Project include radiometric equivalent data (eU3O8) for 4,570 drill holes (4,056 pre-2007), eU3O8 data and PFN assay data for 272 drill holes completed from 2007 to 2013, and eU3O8 and core data for one core hole completed in 2024. For the 2011-2012, drilling programs, down hole geophysical logging using the PFN tool was completed with Strathmore's PFN logging truck and independently confirmed by GAA Wireline Services.

Extensive verification work was previously completed for holes drilled pre-2007 in the 2017, mineral estimate (Beahm, 2017). This Report used the results of the 2007 to 2013 drilling as part of the verification procedures on the pre-2007 drilling. The Authors reviewed this analysis as well as post-2007 drilling raw data.

Mineral Resources

The mineral resource estimates are based on radiometric equivalent uranium grades % eU_3O_8. A minimum 0.02% eU_3O_8, minimum 1.0-foot thickness, and minimum GT of 0.10 was used in the estimations along with a bulk dry density of 16 cubic feet per ton. Resources were estimated using the GT contour method, which is industry standard for this type of deposit. The GT was determined for each drill hole by major stratigraphic horizon, then the GT was summed separately for each mineralized sub-horizon for intercepts meeting the cutoff criteria. Contours were drawn in two-dimensional space around horizon intercepts, allowing projection up to 100 feet across a mineralized trend and up to 600 feet along the mineralized trend.

Average GT for each contour was calculated one of two ways depending on if the contour was the highest GT contour or if it contained another, higher GT contour. If the contour was the highest GT contour, all GT values within the contour were averaged, then averaged with the value of that GT contour. For example, a 1.0 GT contour with two GT values of 1.20 and 1.47 and no higher contour within would be (((1.20+1.47)/2)+1.0)/2 = 1.17 average GT. If the contour contained another higher contour, the average GT was the average of the upper and lower GT contour values. For example, a 1.0 GT contour with a 2.0 GT contour within would be (1.0+2.0)/2 = 1.5 average GT.

Pounds of uranium for each contour were calculated by multiplying the contour area by GT for the contour and applying the conversion constant and dividing by bulk density factor ((Area x Avg GT x 20)/16 = Pounds). Tonnage was calculated by multiplying composited contour thickness by contour area to get cubic feet, then converting to tonnage by applying the density factor (Thickness x Area/16).

The 0.10 GT base case cutoff was selected by meeting economic criteria for both ISR and open pit/heap leach methods differentiated on the relative location to the water table. Resources labeled “ISR” meet the criteria of being sufficiently below the water table to be amenable by ISR methods and as well as also meeting other hydrogeological criteria. “Non-ISR” resources include those generally above the natural water table, which would typically be mined using open pit methods.

Mineral resources were classified as measured, indicated, and inferred based on the distance to the nearest drilling intercept to measure drilling density. To be classified as measured resources, the contour must fall within 100 feet of a mineralized drill hole intercept in that horizon. Indicated resources must fall between 100 and 250 feet from the nearest mineralized intercept in that horizon. Inferred resources must be within 600 feet of a mineralized intercept in that horizon.

The GT contours were divided and classified based on area contained within each of the distance boundaries from drill hole intercepts. After classifying resources based on distance from drilling, further consideration was given to applicable mining methods for each pod. Reclassification of resource was determined based on local water table levels at each resource pod and the level of detail of hydrogeologic understanding.

At this time, only the Central Unit has had groundwater flow modeling completed. All other ISR resources which met the measured criteria for ISR drilling density were classified as indicated resource until more detailed hydrologic studies to support ISR are conducted on these resource areas.

The cutoff used for mineral resource classification was a minimum 0.02% eU3O8, minimum 1.0-foot thickness, and minimum 0.10 GT. These criteria were determined to meet the criteria for “reasonable prospects for economic extraction” for both ISR and open pit heap/leach mining methods. The GT cutoff of 0.10 GT is also consistent with previous historic resource estimation in the area. The average grade of ISR resources in this estimate at a 0.10 GT cutoff met economic criteria for ISR extraction and thus is considered the base case for this Report.

When drawing GT contours, the maximum allowable GT was set at 7.0. Any drilling intercept with a higher GT was included in the 7.0 GT contour and assigned that value.

Measured and Indicated Mineral Resource Summary:

Pounds	Tons	Average Grade	Average Grade %	Average Thickness	Average GT
December 31, GT cutoff					
Measured	2,051,000	994,000	0.10 %	5.35	0.55
Indicated	8,713,000	6,031,000	0.07 %	6.13	0.44
Total Measured and Indicated	10,764,000	7,025,000	0.08 %	6.05	0.46
December 31, 2024 ISR Only (GT cutoff 0.10)					
Measured	2,051,000	994,000	0.10 %	5.35	0.55
Indicated	5,654,000	2,835,000	0.10 %	4.92	0.49
Total Measured and Indicated	7,705,000	3,829,000	0.10 %	4.99	0.50
December 31, 2024, Non -ISR Only (GT cutoff 0.10)					
Indicated	3,059,000	3,196,000	0.05 %	8.60	0.41
Total Measured and Indicated	3,059,000	3,196,000	0.05 %	8.60	0.41

Notes:

1. Mineral resources as defined in 17 CFR § 229.1300.
2. All ISR Only resources occur below the static water table.
3. The point of reference for mineral resources is in-situ at the Project.
4. Mineral resources are not mineral reserves and do not have demonstrated economic viability.
5. An 80% metallurgical recovery factor was considered for the purposes of the economic analysis.
6. Totals may not sum due to rounding.

Inferred Mineral Resource Summary

Pounds	Tons	Average Grade	Average Grade %	Average Thickness	Average GT
December 31, (GT cutoff 0.10)					
Inferred	490,000	514,000	0.05 %	6.16	0.29
December 31, 2024 ISR Only (GT cutoff 0.10)					
Inferred	428,000	409,000	0.05 %	5.94	0.31
December 31, 2024, Non -ISR Only (GT cutoff 0.10)					
Inferred	62,000	105,000	0.03 %	7.01	0.21

Notes:

1. Mineral resources as defined in 17 CFR § 229.1300.
2. All ISR Only resources occur below the static water table.
3. The point of reference for mineral resources is in-situ at the Project.
4. Mineral resources are not mineral reserves and do not have demonstrated economic viability.
5. Totals may not sum due to rounding.

Mining, Processing and Recovery Methods

enCore plans to use the ISR mining technique with a low pH lixiviant at the Project. Gas Hills was one of the major uranium mining and production regions in the USA with cumulative production in excess of 100 million pounds of uranium, mainly from open-pit mining, but also from underground and ISR mining methods. This historical production demonstrated the host Wind River Formation sandstones and the hydrological conditions to be suitable for ISR production.

ISR is employed because this technique allows for the low cost and effective recovery of roll front mineralization. An additional benefit is that ISR is relatively environmentally benign when compared to conventional open pit or underground recovery techniques. ISR does not require the installation of tailings facilities or require significant surface disturbance.

This mining method utilizes injection wells to introduce a lixiviant into the mineralized zone. This PEA assumes a low pH lixiviant will be utilized in the ISR process. Low pH ISR lixiviants have technical and economic advantages over alkaline lixiviants in formations that have relatively low carbonate content and amenable geology. These advantages include potential for higher recovery, shorter leaching duration, lower lixiviant and oxidant requirements, constituent-specific advantages during groundwater restoration, and a higher degree of natural attenuation than alkaline lixiviant. The lixiviant is made of native groundwater fortified with a complexing agent such as sulfuric acid. The complexing agent bonds with the uranium to form uranyl sulfate, which is then recovered through a series of production wells and piped to a processing

plant where the uranyl sulfate is removed from solution using ion exchange. The groundwater is re-fortified with the complexing agent and recirculated to the wellfield to recover additional uranium.

ISR operations consist of four major solution circuits, ion exchange to extract uranium from the mining solution, an elution circuit to remove uranium from the IX resin, a yellowcake precipitation circuit, and a dewatering, drying, and packaging circuit.

Economic Analysis

The economic assessment presented in the Gas Hills Technical Report Summary is based on geological evaluation and mapping of production areas, determining which areas are not viable for production activities due to hydrologic features, and obtaining an 80 percent recovery of the remaining resources.

A cash flow statement has been developed based on the CAPEX, OPEX, and closure cost estimates and the production schedule. The sales price for the produced uranium is assumed at $87.00 per pound for the life of the Project.

The production rate assumes an average solution uranium grade (headgrade) of approximately 97 mg/L. The sales for the cash flow are developed by applying the recovery factor to the Project resource estimate. The total uranium production over the life of the Project is estimated to be 6.16 million lbs.

The production estimates and OPEX distribution used to develop the cash flow are based on the production and restoration models developed by enCore and incorporated in the cash flow. The cash flow assumes no escalation, no debt interest, or capital repayment. It also does not include depreciation. Estimated payback in the post-federal tax cash flow model is near the middle of the third year of production. Net cash flow before income tax over life of the Project is estimated to be $286.0 million and the net after-tax cash flow is estimated at $245.7 million. The Project has an estimated pre-tax Internal Rate of Return (IRR) of 54.8 percent and a Net Present Value (NPV) of $166.9 million. After-tax IRR and NPV are estimated at 50.2 percent and $141.8 million, respectively. The NPV was calculated assuming an 8 percent discount rate. The NPV assumes cash flows take place in the middle of each period. NPV and IRR calculations are based on Year-2 through Year 11 and includes costs escalated by 8 percent per year from Year -4 and Year -3 treated as if the escalated costs occurred in Year-2. This approach to calculating the IRR and NPV was taken because Year -2 is the first year a significant sum of capital is invested in the project. Pre-income tax estimated cost of uranium produced is $40.61 per pound including royalties, severance taxes, ad valorem taxes, plus all operating and capital costs.

Capital Cost Estimates

CAPEX costs were developed based on the current designs, quantities, and unit costs. The cost estimates presented herein are based on personnel and capital equipment requirements, as well as wellfield layouts, process flow diagrams, tank and process equipment and buildings at enCore's Dewey-Burdock Project in western South Dakota as well as other similar uranium projects. The Project has pre-mining development and capital costs of $55.2 million.

After the start of mining, the CAPEX category will include subsequent mine unit drilling and wellfield installation costs as well as construction of transfer pipelines to move water from the Jeep, South Black Mountain, and Central Units to the CPP location in the West Unit. Wellfield development costs used in this analysis were developed based on costs estimated in the Shirley Basin 2024 PEA. The average well depth in the Project is nearly 60 ft. deeper than the average well in the Shirley Basin Project and the monitor wells will target the underlying rather than an overlying aquifer. As such, the costs were escalated to account for these factors. No additional contingency was applied to the CAPEX costs for the purposes of this report.

The first series of header houses will be brought online sequentially until the planned plant throughput (approximately 2,400 gpm) is attained. In the event headgrades at the plant fall below projected values, the CPP as considered in this analysis will have additional capacity (up to 4,400 gpm) to allow for flows to be increased to meet the production target of 1 million pounds of U3O8 per year. The remainder of the additional mine units will be developed in such a way as to allow for plant capacity/production targets to be maintained.

The wellfield development costs include both wellfield drilling and wellfield construction activities and were estimated based on the assumption that the wellfields in this Project will be similar in design to those in the Shirley Basin PEA (WWC, 2024). The wellfield costs include wells, header houses, and the hydraulic conveyance (piping) system associated

with the wellfields. Additionally, trunk and feeder pipelines, electrical service, roads and wellfield fencing are included in the costs.

The accuracy of the CAPEX estimation complies with item 1302 of Regulation S-K for an Initial Assessment with economics.

CAPEX Costs	Year -4	Year -3	Year -2	Year -1	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Totals	$/lb
	($000s except cost per pound data)																
CPP Design and permitting	$ (500.0)	$ (1,000.0)	$ (1,000.0)	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ (2,500.0)	**$ (0.41)**
CPP Construction	$ –	$ –	$ (8,000.0)	$ (22,590.0)	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ (30,590.0)	**$ (4.96)**
Disposal wells	$ –	$ –	$ (250.0)	$ (4,750.0)	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ (5,000.0)	**$ (0.81)**
Transfer Pipelines	$ –	$ –	$ –	$ –	$ –	$ –	$ (3,480.0)	$ (2,320.0)	$ (1,160.0)	$ –	$ –	$ –	$ –	$ –	$ –	$ (6,960.0)	**$ (1.13)**
Wellfields	$ –	$ –	$ (5,832.3)	$ (8,165.2)	$ (11,664.5)	$ (11,664.5)	$ (11,664.5)	$ (11,795.6)	$ (11,244.6)	$ –	$ –	$ –	$ –	$ –	$ –	$ (72,031.2)	**$ (11.69)**
Permitting, Claim Maintenance, and Administrative (G&A)	$ (596.6)	$ (571.6)	$ (962.6)	$ (963.2)	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ (3,094.0)	**$ (0.50)**
Total	**$ (1,096.6)**	**$ (1,571.6)**	**$ (16,044.9)**	**$ (36,468.4)**	**$ (11,664.5)**	**$ (11,664.5)**	**$ (15,144.5)**	**$ (14,115.6)**	**$ (12,404.6)**	**$ –**	**$ –**	**$ –**	**$ –**	**$ –**	**$ –**	**$ (120,175.2)**	**$ (19.50)**

Notes:
1. CPP costs are based on similar sized facility at Dewey-Burdock.
2. Disposal well costs assume only one disposal well will be necessary.
3. Includes costs for large diameter pipelines to transfer fluids between mine units. Pipelines incidental to the wellfield are included in wellfield construction costs.
4. Wellfield costs include all costs and equipment required to drill wells, install pipelines, header houses, etc.
5. G&A costs only included during pre-production period. After production starts, costs are considered operational costs.

Operating Costs Estimates

The OPEX costs have been developed by evaluating and including each process unit operation and the associated required services (power, water, air, waste disposal), infrastructure (offices, shops and roads), salary and benefit burden, and environmental control (heat, air conditioning, monitoring). Total OPEX costs, including selling, production and operating costs have been estimated at $95.6 million, or approximately $15.51 per pound. The costs are based on enCore's estimated costs at the Dewey-Burdock Project and have no additional contingency attached except for escalation for inflation. The prices for the major items identified in this report have been sourced in the United States. Major cost categories considered when developing OPEX costs include wellfield, plant, processing, and site administration costs as detailed in the table below.

The accuracy of the OPEX estimation complies with item 1302 of Regulation S-K for an Initial Assessment with economics.

Life of Mine Operating costs	Year -4	Year -3	Year -2	Year -1	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Totals	$/lb
	($000s except cost per pound data)																
CPP, Disposal wells, Overflow pond	$ –	$ –	$ –	$ –	$ (4,902.8)	$ (6,864.0)	$ (9,805.7)	$ (9,805.7)	$ (9,805.7)	$ (9,805.7)	$ (9,452.7)	$ –	$ –	$ –	$ –	$ (60,442.3)	**$ (9.81)**
Well Field Operation	$ –	$ –	$ –	$ –	$ (991.8)	$ (1,388.5)	$ (1,983.6)	$ (1,983.6)	$ (1,983.6)	$ (1,983.6)	$ (1,912.2)	$ –	$ –	$ –	$ –	$ (12,226.9)	**$ (1.98)**
Aquifer Restoration and Decommissioning	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ (1,522.6)	$ (2,039.6)	$ (2,039.6)	$ (1,779.1)	$ (777.5)	$ (1,441.9)	$ (556.0)	$ (10,156.3)	**$ (1.65)**
U3O8 Conversion and Shipping fees	$ –	$ –	$ –	$ –	$ (205.0)	$ (287.0)	$ (410.0)	$ (410.0)	$ (410.0)	$ (410.0)	$ (395.2)	$ –	$ –	$ –	$ –	$ (2,527.2)	**$ (0.41)**
Permitting, Claim Maintenance, and Administrative (G&A)	$ –	$ –	$ –	$ –	$ (824.9)	$ (824.6)	$ (824.6)	$ (824.6)	$ (824.6)	$ (837.7)	$ (831.9)	$ (831.9)	$ (889.9)	$ (889.9)	$ (897.2)	$ (9,301.8)	**$ (1.51)**
Reclamation Bonding Surity Costs	$ –	$ –	$ –	$ (39.4)	$ (51.3)	$ (78.9)	$ (109.9)	$ (139.1)	$ (136.6)	$ (115.7)	$ (89.7)	$ (83.6)	$ (62.8)	$ (35.1)	$ –	$ (942.1)	**$ (0.16)**
Bond collateral	$ –	$ –	$ –	$ (460.2)	$ (181.3)	$ (345.2)	$ (386.7)	$ (365.1)	$ 30.7	$ 261.7	$ 325.2	$ 423.8	$ 173.4	$ 231.0	$ 292.5	$ 0.0	**$ 0.00**
Total	**$ –**	**$ –**	**$ –**	**$ (499.6)**	**$ (7,157.1)**	**$ (9,788.2)**	**$ (13,520.5)**	**$ (13,528.1)**	**$ (14,652.4)**	**$ (14,930.6)**	**$ (14,396.1)**	**$ (2,270.8)**	**$ (1,556.8)**	**$ (2,135.9)**	**$ (1,160.7)**	**$ (95,596.6)**	**$ (15.51)**

Notes:
1.CPP, Disposal wells, and Overflow Pond costs include power, labor, maintenance, chemicals and other costs associated with operation of the facilities.
2. Wellfield operation costs include labor, equipment, power, maintenance, chemicals and other wellfield operation costs.
3. Decommissioning costs assume no salvage value for materials and equipment.
4. Conversion and shipping fees assume shipments from Gas Hills CPP to conversion facility in Metropolis, Illinois
5. Reclamation bonding surety costs assume a 3% premium on the bond estimate prior to positive cashflow and 2% premium after positive cashflow.
6. Bond collateral assumed to be equal to 35% of the bond estimate prior to positive cashflow and then 25% of the bond estimate after positive cashflow.

Sensitivity Analysis

The Project is sensitive to changes in the price of uranium. Assuming an 8 % discount rate, a $5.00 per pound change in the uranium price adjusts the pre-federal income tax NPV by just over $18 million and the post-federal tax NPV by just over $15 million. A $5.00 per pound increase in uranium price adjusts the pre-tax and post-tax IRR by approximately 3 %.

Assuming an 8 % discount rate and a constant uranium price of $87.00 per pound of U_3O_8, CAPEX and OPEX costs were varied in both the pre- and post-federal income tax cashflow models to evaluate effects on NPV. A 5% change in CAPEX

and OPEX costs can impact the NPV by approximately $5.6 million and $2.6 million, respectively. The IRR is also affected by changes in CAPEX and OPEX costs. A 5% change in OPEX costs adjusts the IRR by approximately 2 % in the pre-tax cashflow model.

A 5% change in the OPEX and CAPEX costs can have an impact to the NPV of approximately $3.0 million and $5.7 million in both the pre- and post-tax cashflow models, respectively. The IRR is also affected by changes in OPEX and CAPEX costs. The changes in IRR are not linear.

Planned Work

In 2025, the Company plans to complete environmental data collection necessary to prepare an application for a source material license and a permit to mine with the State of Wyoming. Additionally, the Company expects to begin preliminary work on an application for a plan of operations from the U.S. Bureau of Land Management.

Seasonality

The timing of our uranium concentrate sales are dependent upon factors such as extraction results from our uranium recovery activities, cash requirements, contractual requirements and perception of the uranium market. As a result, our sales are neither tied to nor dependent upon any particular season. In addition, our ability to extract and process uranium does not change on a seasonal basis.

Environmental, Social, and Governance Principles

The long-term success of enCore requires the integration of sustainability into all aspects of its business. Leading environmental, social and governance performance ("ESG") is strongly correlated to strong financial performance and the creation of long-term value for enCore's shareholders and other stakeholders. This includes striving to meet the highest standards, contributing toward sustainable development, and serving as responsible natural resource stewards to make positive and lasting impacts on the communities where we operate. enCore is responsible to its shareholders, governments, and community stakeholders as the Company's projects are advanced, and we consider appropriate best practices and innovative methods to meet and exceed these standards where practical, within our financial means. The Company announced on October 21, 2024, the release of its inaugural Sustainability Report that provides details on the Company's commitment to ESG performance, and the report provides measurable goals for demonstrating performance for key ESG metrics. The Company's Sustainability Report can be found at its website, https:// encoreuranium.com.

Land Tenure

The Company's land holdings in the U.S. are held either by leases from the fee simple owners (private parties or the State) or unpatented mining claims located on property owned and managed by the U.S. Federal Government. Annual fees must be paid to maintain unpatented mining claims, but work expenditures are not required. Holders of unpatented mining claims are generally granted surface access to conduct mineral exploration and extraction activities. However, additional permits and plans are generally required prior to conducting exploration or mining activities on such claims.

Government and Environmental Regulations

Government Regulations

The Company's properties and facilities are subject to extensive laws and regulations which are overseen and enforced by multiple federal, state and local authorities. These laws govern exploration, construction, extraction, recovery, processing, exports, various taxes, labor standards, occupational health and safety, waste disposal, protection and remediation of the environment, protection of endangered and protected species, toxic and hazardous substances, and other matters. Uranium minerals exploration, extraction, recovery, and processing are also subject to risks and liabilities associated with the perceived potential for impacts to the environment and disposal of waste products occurring as a result of such activities.

Compliance with these laws and regulations may impose substantial costs on the Company and may subject the Company to significant potential liabilities. Changes in these regulations or changes in regulatory attitudes or interpretations could require the Company to expend significant resources to comply with new laws or regulations, attitudes or interpretations relating thereto, or changes to current requirements and could have a material adverse effect on the Company's business operations. However, compliance with government regulations generally, including but not limited to environmental regulations, is an integral part of the Company's day-to-day business and impacts virtually all the Company's capital

expenditure and operating decisions at its facilities, as the Company's facilities and operations must comply with this extensive array of environmental, health and safety laws and regulations. The costs of compliance with these laws and regulations are therefore well understood and assumed by the Company in all its capital budgeting decisions, project analyses and cost and earnings projections. As all the Company's competitors in the uranium mining industry in the U.S. face the same or similar regulatory requirements, the Company does not believe its need to comply with this extensive array of laws and regulations materially affects the Company's competitive position within the U.S. uranium mining industry.

Environmental Regulations

Our operations where exploration, development and operations are taking place, are subject to extensive laws and regulations which are overseen and enforced by multiple federal, state and local authorities. These laws and regulations govern exploration, development, various taxes, labor standards, occupational health and safety including radiation safety, waste disposal, underground source of drinking water, protection and remediation of the environment, protection of endangered and protected species, toxic and hazardous substances and other matters. Uranium minerals exploration is also subject to risks and liabilities associated with pollution of the environment and disposal of waste products occurring as a result of mineral exploration.

Compliance with these laws and regulations imposes substantial costs on us and may subject us to significant potential liabilities or impacts to operations or project development. Changes in these regulations could require us to expend significant resources to comply with new laws or regulations or changes to current requirements and could have a material adverse effect on our business operations. Compliance with all current regulations, including but not limited to the environmental and safety regulatory schemes, is an integral part of our day-to-day business, management and staff commitment and expenditures. The costs attendant to compliance are understood and routinely budgeted and are generally comparable to those of other U.S. uranium companies and other natural resources companies in the U.S. and Canada. It should be noted that environmental protections and regulatory oversight thereof vary significantly outside North America, particularly in Kazakhstan and Russia, where state-owned enterprises operate with only limited regulatory oversight related to environmental and worker safety.

Mineral exploration and development activities, as well as our uranium recovery operations, are subject to comprehensive regulation which may cause substantial delays, restrictions or require capital outlays in excess of those anticipated, causing an adverse effect on our business operations. Mineral exploration operations are also subject to federal and state laws and regulations that seek to maintain health and safety standards. Various permits from government bodies are required for drilling operations to be conducted; no assurance can be given that such permits will be received. Environmental standards imposed by federal and state authorities may be changed and any such changes may have material adverse effects on our activities. Mineral recovery operations are subject to federal and state laws relating to the protection of the environment, including laws regulating removal of natural resources from the ground and the discharge of materials into the environment. The posting of a performance bond and the costs associated with our permitting and licensing activities require a substantial budget and ongoing cash commitments. In addition to pursuing ongoing permitting and licensure for new projects and additions to our existing projects, these expenditures include ongoing monitoring (e.g., wildlife, groundwater and effluent monitoring) and other activities to ensure regulatory and legal compliance, as well as compliance with our permits and licenses.

We believe that we comply with all federal, state and local applicable laws and regulations which govern environmental quality and pollution control. The appropriate regulatory agencies do conduct routine and regular inspections of activities by the Company at all of its operating and past operating sites, and to date, the Company has not been notified of any material non-compliance that would require any form of financial penalty or operating restriction.

In November 2023, the Company received renewed license approval from the TCEQ for the Company's combined South Texas CPPs at its Rosita, Kingsville Dome and Vasquez uranium projects. The renewed license allows for the removal of two IX units at the Rosita CPP and wellfield.

A Source and Byproduct Materials License was issued by the NRC in April of 2014 for our Dewey-Burdock Project. The State of South Dakota Large Scale Mine Permit ("LSMP") has been recommended for approval by the South Dakota Department of Environment, and draft UIC Class III and Class V permits were initially issued in March 2017 and reissued in August 2019.

Licenses and Permits

In Texas, the TCEQ regulates uranium recovery and issues the necessary licenses and permits. A Radioactive Material License issued by TCEQ covers the Rosita, Kingsville Dome and Vasquez projects, and it was renewed in May 2021. Each site also has Class I non-hazardous injection permits for operation of waste disposal wells on site, which are also regulated by the TCEQ. All permits for the disposal wells are active.

The Rosita Project includes four TCEQ production area authorizations ("PAA") that could allow for low cost and accelerated timeline to extraction. Production areas 1 and 2 are depleted, and groundwater restoration has been completed to regulatory standards. Production areas 3 has been depleted by previous uranium extraction operations that were shut in in 2008. Production Area 5 is currently undergoing uranium extraction. In 2013, enCore completed the final phase of TCEQ required stabilization in production areas 1 and 2.

The Alta Mesa Uranium Project is a fully licensed and constructed ISR project. The current Radioactive Materials License and Class III Underground Injection Control Permit are in timely renewal. Production Areas 1 through 4 have been depleted and the groundwater in Production Area 1 has been restored. Production Areas 5 and 6 have been partially extracted and will be restarted with future extraction operations. Production Area 7 is currently undergoing uranium extraction operations. The Alta Mesa Project has two fully permitted Class I non-hazardous injection permits for the operation of two disposal wells on site.

The Company's Upper Spring Creek – Brown Uranium Project is currently partially permitted. It currently has an aquifer exemption and a Class III Underground Injection Control Permit. The Company has applied to amend the Radioactive Materials License for the Rosita CPP to incorporate the wellfields and satellite IX facility for the project.

Waste Disposal

The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes affect mineral exploration and uranium recovery activities by imposing regulations on the generation, transportation, treatment, storage, disposal and cleanup of "hazardous wastes" and on the disposal of non-hazardous wastes. Under the auspices of the EPA, the individual states administer some or all the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements.

Comprehensive Environmental Response, Compensation and Liability Act

The federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") imposes joint and several liability for costs of investigation and remediation and for natural resource damages, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances (collectively, "Hazardous Substances"). These classes of persons or potentially responsible parties include the current and certain past owners and operators of a facility or property where there is or has been a release or threat of release of a Hazardous Substance and persons who disposed of or arranged for the disposal of the Hazardous Substances found at such a facility. CERCLA also authorizes the EPA and, in some cases, third parties, to take actions in response to threats to the public health or the environment and to seek to recover the costs of such action. We may also in the future become an owner of facilities on which Hazardous Substances have been released by previous owners or operators. We may in the future be responsible under CERCLA for all or part of the costs to clean up facilities or properties at which such substances have been released and for natural resource damages.

Air Emissions

Our operations are subject to local, state and federal regulations for the control of emissions of air pollution. Major sources of air pollutants are subject to more stringent, federally imposed permitting requirements. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could require us to forego construction, modification or operation of certain air emission sources. In Texas, the TCEQ issues an exemption for those processes that meet the criteria for low to zero emission by issuing a permit by rule.

Water Management

We commit our management team, employees and contractors to be good stewards of the water it utilizes in all parts of its operations. From exploration to restoration, water is the critical factor for ISR projects and responsibly managing that water is crucial to our business.

At all our ISR projects the ore hosted groundwater does not meet either primary or secondary drinking water standards and should only be used for industrial or agricultural use without proper treatment.

Water consumption at our ISR projects is primarily natural groundwater. During the recovery process, water is pumped from the ore hosted aquifer and piped to the satellite facility. The groundwater is filtered for solids, stripped of uranium, and then approximately 95% is re-injected or recirculated back into the same aquifer it was recovered from. This recycling process is an advantage of ISR extraction compared to other methods such as conventional or open pit mining operations that may require significant groundwater de-watering to facilitate safe mining.

In order to ensure appropriate water management, and to ensure our team can continuously make decisions to reduce our water usage, we closely monitor our water consumption. We are identifying ways to reduce water consumption on an ongoing basis.

Compliance with the Clean Water Act

The Clean Water Act ("CWA") imposes restrictions and strict controls regarding the discharge of wastes, including mineral processing wastes, into waters of the U.S.; a term broadly defined. Permits must be obtained to discharge pollutants into federal waters. The CWA provides for civil, criminal and administrative penalties for unauthorized discharges of hazardous substances and other pollutants. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or hazardous substances. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other hazardous substances, into state waters. In addition, the EPA has promulgated regulations that may require us to obtain permits to discharge storm water runoff. Management believes that we are in substantial compliance with current applicable environmental laws and regulations. The Company has no discharges that are regulated by the Clean Water Act at any of its current and planned operations.

GHG Emissions Management

Mining is an essential industry to enable the global transition to net-zero. Uranium recovery using ISR technology, at the heart of our business, fuels nuclear energy, which is an essential carbon-free energy source. Beyond this, we understand that our operational activities do release emissions that are considered to contribute to climate change. Therefore, over the next several years we will begin a process to understand our emissions profile, as well as identify and implement opportunities to reduce emissions, where and when possible. In October 2024, the Company issued its inaugural Sustainability Report, and in that report, a preliminary assessment of Scope 1 and 2 emissions was provided. The Company has set a goal of completing a baseline assessment Scope 1, 2, and 3 greenhouse gas emissions for its operations by the end of calendar year 2026.

Item 1A. Risk Factors

The Company is subject to risks, certain of which are described below. The occurrence of any one or more of these risks or uncertainties could have a material adverse effect on the value of any investment in the Company and the financial condition or operating results of the Company. Additional risks and uncertainties not presently known to the Company or that the Company currently deems immaterial may also impair the Company's business operations. Due to the nature of the Company and its business, investors should carefully consider all such risks, including those set out in the discussion below, together with the other information in this Annual Report and our other filings with the SEC and Canadian Securities Administrators, together with the other information in this Annual Report and our other filings with the SEC and Canadian Securities Administrators.

Summary Risk Factors

The following is a summary of some of the risks and uncertainties that could materially adversely affect our business, financial condition and results of operations. You should read this summary together with the more detailed description of each risk factor contained below.

- our history of negative operating cash flows and our ability to develop or maintain positive cash flow from our mining activities;
- ability to obtain additional financing on acceptable terms when needed;
- we have experienced negative cash flows from operations and may need additional financing in connection with the implementation of our business and strategic plans from time to time;
- our expansion-by-acquisition strategy;
- our properties do not contain Mineral Reserves and some of our properties, projects and facilities may not be economic within a reasonable time period or at all;
- reliance on key personnel, contractors and experts;
- conflicts of interest of our directors and officers;
- risks associated with exploration of, development of, and extraction from mineral properties;
- our reliance on third party drilling contractors, including an increased risk of loss, weather related risks or underutilization of drilling rigs;
- risks inherent to mineral exploration and extraction;
- the commercial viability of economic extraction of minerals from uranium deposits;
- the subjectiveness and uncertainty of estimations of Mineral Resources;
- future mineral extraction estimates may not be achieved;
- estimates of commodity prices used in preliminary economic assessments may never be realized;
- requirements to obtain or retain key permits to advance or achieve extraction;
- involvement of Native American tribes in the permitting process;
- opposition to mining may disrupt our business activities;
- challenges to title of our mineral property interests;
- our ability to attract, retain, train, motivate, develop and transition skilled employees;
- existing competition and geopolitical changes in the competitive landscape;
- public opinion and perception of nuclear energy;
- volatility in market prices of uranium;
- applicable laws, regulations and standards, including environmental protection laws and regulations;
- our ability to raise equity or obtain debt;
- accuracy of extraction, capital and operating cost estimates;
- ability of novel mining methods for extraction to yield anticipated results;
- the need for technical innovation and risk of obsolescence;
- availability of a public market for uranium, including global demand and supply;
- changes to and uncertainty in U.S. trade policy, tariff and import/export regulations;
- risk related to our operations on federal lands, including potential designation of national monuments or withdrawal or permits;
- risks related to our Alta Mesa joint venture;
- taxation implications of U.S. holders because the Company may be passive foreign investment company;
- potential dilution if we issue additional common shares or securities convertible into common shares;
- price volatility of our common shares;

- our expectation to not declare or pay dividends; and
- reliance on information technology systems and cybersecurity risks;
- the time and resources necessary to comply with corporate governance practices and securities rules and regulations in the United States and Canada;
- our management's ability to maintain effective internal controls;
- our remediation plan and ability to remediate the material weaknesses in our internal controls over financial reporting;
- United States investors may face challenges in enforcing civil liabilities against the Company, its directors, and its officers;
- taxation implications of U.S. holders because the Company may be passive foreign investment company;
- our ability to protect our proprietary data, technology and intellectual property;
- changes in climate conditions; and
- other risks described in this Annual Report, as more particularly described herein.

Risks related to enCore's Business and Operations

We are an exploration stage company with a history of negative operating cash flows and we may never develop or be unable to maintain positive cash flow from our mining activities.

For the year ended December 31, 2024, enCore had negative operating cash flow and will require significant cash and/or alternative financing arrangements in order to develop its assets and meet its ongoing general and administrative costs and exploration commitments and to maintain its mineral property interests, which may require working capital and/or project financing in the future. As an exploration company, the Company has no source of operating cash flow and its operations to date have been funded primarily from equity financings. As a result of the expenses to be incurred by the Company in connection with its business objectives for the development of the Company's material projects, the Company anticipates that negative operating cash flows will continue for the foreseeable future. Accordingly, the Company will require substantial additional capital in order to fund its future exploration and development activities for its material projects. The Company does not currently have any arrangements in place for this funding and there is no assurance that such funding will be achieved when required. Any failure to obtain additional financing on favorable terms or failure to achieve profitability and positive operating cash flows will have a material adverse effect on enCore's financial condition and results of operations.

We may need additional financing in connection with the implementation of our business and strategic plans from time to time.

The exploration, construction, development and acquisition of mineral properties and the ongoing operation of mines and other facilities requires a substantial amount of capital and may depend on our ability to obtain financing through joint ventures, debt financing, equity financing or other means. We may accordingly need further capital in order to take advantage of further opportunities or acquisitions. Our financial condition, general market conditions, volatile uranium and vanadium markets, volatile interest rates, legal claims against us, a significant disruption to our business or operations, or other factors may make it difficult to secure financing necessary for the expansion of mining activities or to take advantage of opportunities for acquisitions. Further, volatility in the credit markets may increase costs associated with debt instruments due to increased spreads over relevant interest rate benchmarks, or may affect our ability, or the ability of third parties we seek to do business with, to access those markets.

Continued volatility in equity markets, specifically including energy and commodity markets, may increase the costs associated with equity financings due to a low share price and may create the potential need for us to offer higher discounts and other value (e.g., warrants). There is no assurance that we will be successful in obtaining required financing as and when needed on acceptable terms, if at all.

We have experienced negative cash flows from operations and may need additional financing in connection with the implementation of our business and strategic plans from time to time.

The Company has had negative cash flow from operations in prior years, and at low commodity prices a number of our mining properties will be on standby, making it less likely that the Company will be able to generate positive cash flows from operations in those circumstances. If the Company cannot generate positive cash flows from operations, its ability to fund its operations and implement its business plans may depend on its ability to obtain financing through joint ventures, debt financing, equity financing or other means. There can be no assurance that we will be able to achieve and maintain

positive cash flow from operations to fund our financing needs. Further, if cash flows from operations are negative, there is no assurance that the Company will be able to raise additional funds, if needed, or that if any such additional funds are raised, that the Company will be able to raise such funds on commercially attractive terms. If we do not achieve positive cash flows or are unable to raise additional funds when needed, we may not be able to continue to fund our operations.

Our corporate strategy includes acquisitions of mining assets and businesses. Such acquisitions are subject to risks and we may not realize the anticipated benefits of an acquisition.

enCore has completed a number of transactions over the last several years and from time to time may evaluate opportunities to acquire uranium mining assets and businesses. Despite the Company's belief that these transactions were, and others which may be completed in the future will be, in the Company's best interest and benefit the Company and its shareholders, the Company may not realize the anticipated benefits of such transactions or realize the full value of the consideration paid or received to complete the transactions. In addition, acquisitions may be significant in size, may change the scale of enCore's business and may expose it to new geographic, political, operating, financial and geological risks. enCore's success in its acquisition activities depends on its ability to identify suitable acquisition candidates, acquire them on acceptable terms and integrate their operations successfully with those of enCore. Any acquisitions would be accompanied by risks, such as the difficulty of assimilating the operations and personnel of any acquired companies; the potential disruption of enCore's ongoing business; the inability of management to maximize the financial and strategic position of enCore through the successful incorporation of acquired assets and businesses; additional expenses associated with amortization of acquired intangible assets; the maintenance of uniform standards, controls, procedures and policies; the impairment of relationships with employees, customers and contractors as a result of any integration of new management personnel; dilution of enCore's present shareholders or of its interest in its subsidiaries as a result of the issuance of shares to pay for acquisitions; and the potential unknown liabilities associated with acquired assets and businesses. There can be no assurance that enCore would be successful in overcoming these risks or any other problems encountered in connection with such acquisitions, which could result in accounting impairments, write-downs of the carrying values of mineral properties or other assets and could accordingly have a material adverse effect on its business, results of operations, financial condition, cash flows and liquidity.

There is no right for our shareholders to evaluate the merits or risks of any future acquisition undertaken by enCore except as required by applicable laws and regulations.

Our properties do not contain Mineral Reserves under S-K 1300, and some of the Company's properties, projects and facilities may not be economic at any point in time or at all.

None of our properties currently contain any known Mineral Reserves. Some or all of our properties, projects and facilities may not be economic for uranium, extraction, recovery or processing at any point in time. Generally, we intend to continue to hold, and in certain cases advance, properties, projects and facilities which may not be economic at any point in time in anticipation of possible future increases in the prices of uranium, as the case may be. However, in those circumstances, there can be no assurance at any time that such prices will ever, or within a reasonable time period, increase to the levels required to advance those properties or, in the case of projects or facilities on standby, to resume exploration, extraction, recovery or processing activities at those projects or facilities. In the event of depressed commodity prices, we would continue to hold our standby properties, projects and facilities because we believe that prices are likely to rise, to such levels within a reasonable time period to justify future production. This ability to maintain scalability as commodity prices increase is a key component of our business strategy. However, as there is a cost associated with holding and, in some cases, maintaining such properties, projects and facilities on standby during periods of depressed commodity prices, in those circumstances we continuously evaluate, on a case-by-case basis, such costs against the prospects for price increases, and may from time to time sell, drop or reclaim any such properties, projects or facilities.

Mining on properties having no known Mineral Resources or Mineral Reserves is inherently speculative and may not prove to be economic at any point in time or at all.

Mining is an inherently speculative business. Some of the properties on which we have the right to mine are not known to have any Mineral Reserves or Mineral Resources. There is a possibility that we will not discover uranium on any or all of our properties which can be mined or extracted at a profit at any point in time or at all. Even if we do discover and mine such minerals, the deposits may not be of the quality or size necessary for us or a potential purchaser of the property to make a profit from mining it. Few properties that are explored are ultimately developed into producing mines, and mines that are developed may not be profitable. Unusual or unexpected geological formations, geological formation pressures, fires, power outages, labor disruptions, flooding, explosions, cave-ins, landslides and the inability to obtain suitable or adequate machinery, equipment or labor, as well as all necessary licenses and permits, are just some of the many risks involved in mineral exploration programs and their subsequent development. However, we may elect, now or in the future, to proceed with the extraction of minerals on one or more of those projects without having completed the technical work

required to declare a Mineral Reserve. If we are then unable to extract uranium in commercially viable quantities, the capital investment of mining such properties may be lost and could materially impact our business.

We may not realize any or all of the anticipated benefits from the Alta Mesa uranium project.

As part of our business strategy, we expect to see certain near-term benefits, including licensed uranium production facility with licensed and permitted Mineral Resources that will add to our overall production capacity in South Texas, as well as longer-term opportunities for growth from a large contiguous mineral property that has significant identified Mineral Resources and the potential for additional Mineral Resources that could be discovered on that property. Any benefits and growth that we realize from such efforts may differ materially from our estimates. In particular, our estimates of the potential benefits and growth from the acquisition of the Alta Mesa Project are based in part on a valuation of the Alta Mesa Project that may differ from the performance of the Alta Mesa Project on a going-forward basis. Achieving the benefits of the acquisition of the Alta Mesa Project will depend, in part, on our ability to integrate operations of the Project successfully and efficiently with our business. The challenges involved in this integration, which may be complex and time-consuming, include the following:

- the diversion of management attention from other important business objective;
- the ability to locate, hire and retain experienced staff to construct wellfields and safely conduct operation;
- the ability to locate, hire and retain experienced contractors to allow efficient delineation drilling and well installation at a necessary rate to meet production needs; and
- the Company's ongoing relations with Boss with respect to the joint venture in the Alta Mesa Project.

In addition, any benefits that we realize may be offset, in whole or in part, by reductions in revenues, or through increases in other expenses, including costs to achieve our estimated synergies and growth. Our plans for the Alta Mesa Project are subject to numerous risks and uncertainties that may change at any time. We cannot assure you that our initiatives will be completed as anticipated or that the benefits we expect will be achieved on a timely basis or at all. It may take longer than expected to achieve the anticipated benefits and growth and there is no guarantee that the Alta Mesa Project will reach near-term production. If the Alta Mesa Project does not achieve the anticipated benefits and growth or reach near-term production, this may adversely affect the future financial results of the Company.

There may be potential undisclosed liabilities associated with the Alta Mesa acquisition.

In connection with the Alta Mesa Acquisition, there may be liabilities that the Company failed to discover or was unable to accurately quantify in its due diligence, which it conducted prior to the execution of the Acquisition Agreement, and the Company may not be indemnified for some or all of these liabilities, which may negatively affect securityholders. The discovery of any material liabilities, or the inability to obtain full recourse for such liabilities, could have a material adverse effect on the Company's business, financial condition or future prospects.

We depend on key personnel, and our success will depend on our continued ability to retain and attract such qualified personnel.

enCore is dependent on the services of key management personnel. The loss of any of these key personnel, if not replaced, could have a material adverse effect on enCore's business and operations. enCore does not currently have key-person insurance on these individuals.

Timely availability and training, strong retention rates of staffing and timely retention of contractors cannot be assured in our industry, many aspects of which are highly specialized. This is particularly true in the current labor markets in which we recruit our employees and contractors, including where we compete with higher paying energy jobs, and because of the remote locations for which employees and contractors are needed. The skilled professionals with expertise in geologic, engineering and process aspects of uranium ISR, radiation safety and other facets of our business are currently in high demand, as there are relatively few professionals with both expertise and experience.

Certain directors and officers may be subject to conflicts of interest with respect to the Company due to their relationship with other resource companies.

enCore's directors and officers may serve as directors or officers of other resource companies or have significant shareholdings in other resource companies and, to the extent that such other companies may participate in ventures in which enCore may participate, the directors and officers of enCore may have a conflict of interest in negotiating and concluding terms respecting the extent of such participation. In the event that such a conflict of interest arises at a meeting of enCore's directors, a director who has such a conflict will abstain from voting for or against the approval of such participation or such terms in accordance with the BCBCA. From time to time several companies may participate in the acquisition, exploration and development of natural resource properties thereby allowing for their participation in larger programs, permitting involvement in a greater number of programs and reducing financial exposure in respect of any one program. It may also occur that a particular company will assign all or a portion of its interest in a particular program to another of these companies due to the financial position of the company making the assignment. In accordance with the laws of British Columbia, the directors of enCore are required to act honestly, in good faith and in the best interests of enCore. Interests of directors and officers in a particular program or other resource company may conflict with the interest of our shareholders in earning income on their investment in our common shares.

Risks related to our Industry

There are risks associated with the exploration of, development of, and production from mineral properties.

The business of exploration for minerals involves a high degree of risk. Few properties that are explored are ultimately developed into producing mines. There is no assurance that the exploration programs on enCore's current or future mineral properties will result in the discovery of new resources or lead to the development of a commercially viable orebody.

Development of any of enCore's properties are subject to numerous risks, including, but not limited to, delays in obtaining equipment, material and services essential to developing the projects in a timely manner; changes in environmental or other government regulations; currency exchange rates; labor shortages; and fluctuation in metal prices. Furthermore, the economic feasibility of developing a mineral project is based on many factors such as estimation of mineral reserves, tonnage and grade, anticipated metallurgical recoveries, environmental considerations and permitting, future metal prices and anticipated capital and operating costs of these projects, and it is possible that actual capital and operating costs and economic returns will differ significantly from those estimated for a project prior to production.

enCore's mineral properties have no operating history upon which estimates of future projection and cash operating costs can be based. Estimates of mineral resources, proven and probable mineral reserves and cash operating costs are, to a large extent, based upon the interpretation of geologic data obtained from drill holes and other sampling techniques. The results of feasibility studies that derive estimates of capital and operating costs based upon the quantity, grade and configuration of mineral reserves as well as the expected recovery rates of metals from the mineralized material, are subject to change. As a result, it is possible that actual capital and operating costs and economic returns will differ significantly from those currently estimated for a project prior to development or operation. The remoteness and restrictions on access of certain of the properties in which enCore has an interest could have an adverse effect on profitability in that infrastructure costs would be higher. There are also physical risks to the exploration personnel working in the rugged terrain, often in poor climate conditions, which can be abated through safety training, adherence to high safety standards and the use of modern communication technologies.

With all mineral operations there is uncertainty and, therefore, risk associated with operating parameters and costs resulting from the scaling up of extraction methods tested in laboratory conditions. Development of a mineral property does not assure a profit on the investment or recovery of costs. In addition, extraction hazards or environmental damage could greatly increase the cost of operations, and various operating conditions may adversely affect the production from mineral properties. These conditions include delays in obtaining governmental approvals or consents, insufficient transportation capacity or other geological, geotechnical and mechanical conditions. While diligent supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays from normal operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

The nature of our use of independent contractors to conduct drilling rig operations presents inherent risks of loss, including weather-related risks, that could adversely affect our results of operations.

Our business relies on the use of independent drilling rig contractors, and their operations are subject to many hazards inherent in the drilling industry, including environmental pollution, blowouts, cratering, explosions, fires, loss of well control, loss of or damage to the wellbore or underground reservoir, damaged or lost drilling equipment and damage or loss from inclement weather or natural disasters, whether or not climate related. Any of these hazards could result in personal injury or death, damage to or destruction of equipment and facilities, suspension of operations, environmental and natural resources damage, reputational harm and damage to the property of others.

Accidents may occur, we may be unable to obtain desired contractual indemnities, and our insurance may prove inadequate in certain cases. The occurrence of an event for which we are not sufficiently insured or indemnified, or the failure or inability of a customer or insurer to meet its indemnification or insurance obligations, could result in substantial losses that could adversely affect our business, financial condition and liquidity. In addition, insurance may not be available to cover certain risks, including war and political risks. Even if available, insurance may be inadequate or insurance premiums or other costs may increase significantly in the future, making insurance prohibitively expensive.

We expect to continue facing upward pressure in our insurance renewals, our premiums and deductibles may be higher, and some insurance coverage may either be unavailable or more expensive than it has been in the past. Moreover, our insurance coverage generally provides that we assume a portion of the risk in the form of a deductible or self-insured retention. We may choose to increase the levels of deductibles (and thus assume a greater degree of risk) from time to time in order to minimize our overall costs, which could exacerbate the effect of our losses on our financial condition and liquidity. In addition, our safety record is a competitive advantage for us and if one or more incidents were to occur it could significantly affect this advantage.

We are subject to the risks and hazards normally encountered by companies in the mineral exploration and extraction industry.

enCore's business is subject to a number of risks and hazards, including environmental hazards; industrial accidents; labor disputes; catastrophic accidents; fires; blockades or other acts of social activism; changes in the regulatory environment; impact of non-compliance with laws and regulations or the implementation of new laws and regulations; natural phenomena, such as inclement weather conditions, underground floods, earthquakes, pit wall failures, ground movements, tailings pipeline and dam failures and cave-ins; and encountering unusual or unexpected geological conditions and technological failure of mining methods.

In addition, success in exploration is dependent on a number of factors including the quality of management, quality and availability of geological expertise and the availability of exploration capital. Major expenses may be required to establish reserves by drilling, constructing mining or processing facilities at a site, developing metallurgical processes and extracting uranium from ore.

There is no assurance that the foregoing risks and hazards will not occur or will not result in damage to, or destruction of, the properties and assets of enCore, personal injury or death, environmental damage, delays in or interruption of or cessation of production from the properties or impairment of enCore's exploration or development activities or in unsuccessful exploration, which could result in unforeseen costs, monetary losses and potential legal liability and adverse governmental action, all of which could have an adverse impact on enCore's future cash flows, earnings, results of operations and financial condition.

The Company risks potential for obsolescence, unexpected maintenance costs, dependence on the lessor's financial stability, potential for damage or loss of equipment, and not having full control over asset usage due to lease terms.

The Company owns two drilling rigs that it will lease to its existing independent contractors to provide the ability for them to capitalize additional drilling capacity and support the Company's exploration drilling program. There is a risk that the leased equipment could become outdated quickly, leaving us with technology that is no longer suitable for our needs. Drilling rigs are known to carry high maintenance costs, and while leases may include some maintenance, unforeseen repairs or significant maintenance needs could result in additional costs not factored into the lease agreement. As a lessor, we do not control the equipment while it is operated by the lessee there could be a serious incident such as a fatality, serious injury, or serious damage our leased equipment.

Economic extraction of minerals from uranium deposits may not be commercially viable.

Whether a uranium deposit will be commercially viable depends on a number of factors, including the particular attributes of a deposit, such as its size and grade; costs and efficiency of the recovery methods than can be employed; proximity to infrastructure; financing costs; and governmental regulations, including regulations relating to prices, taxes, royalties, infrastructure, land use, worker health and safety, importing and exporting of commodities and environmental protection. The effect of these factors, either alone or in combination, cannot be accurately predicted and their impact may result in enCore not being able to economically extract minerals from any identified mineral resource.

Estimation of Mineral Resources is subjective and uncertain.

The figures presented for Mineral Resources in this Annual Report are only estimates. The estimating of Mineral Resources is a subjective process and the accuracy of Mineral Resource estimates is a function of the quantity and quality of available data, the accuracy of statistical computations, and the assumptions used and judgments made in interpreting available engineering and geological information.

There are numerous uncertainties inherent in estimating quantities of Mineral Resources, including many factors beyond our control, and no assurance can be given that the recovery of Mineral Resources, or even estimated Mineral Reserves, will be realized. In general, estimates of mineral resources are based upon several factors and assumptions made as of the date on which the estimates were determined, including (i) geological and engineering estimates that have inherent uncertainties and the assumed effects of regulation by governmental agencies; (ii) the judgment of the geologists, engineers and other professionals preparing the estimate; (iii) estimates of future uranium prices and operating costs; (iv) the quality and quantity of available data and the interpretation of that data; and (v) the accuracy of various mandated economic assumptions, all of which may vary considerably from actual results.

All estimates are, to some degree, uncertain; with ISR, this is due in part to limited sampling information collected prior to mining. For these reasons, estimates of the recoverable Mineral Resources prepared by different professionals or by the same professionals at different times, may vary substantially. As such, there is significant uncertainty in any Mineral Resource estimate and actual deposits encountered and the economic viability of a deposit may differ materially from our estimates.

Estimated Mineral Resources may have to be re-estimated based on changes in uranium prices, further exploration or development activity or actual production experience. This could materially and adversely affect estimates of the volume or grade of mineralization, estimated recovery rates or other important factors that influence Mineral Resource estimates. Mineral Resources are not Mineral Reserves and there is no assurance that any resource estimate will ultimately be reclassified as proven or probable reserves. Mineral Resources which are not Mineral Reserves do not have demonstrated economic viability. There is significant uncertainty in any Mineral Resource estimate and the actual deposits encountered and the economic viability of a deposit may differ materially from enCore's estimates.

No assurances can be given that future mineral production estimates will be achieved.

Estimates of future production for enCore's mining operations as a whole are derived from enCore's mining plans. These estimates are subject to change. enCore cannot give any assurance that it will achieve its production estimates. enCore's failure to achieve its production estimates could have a material and adverse effect on any or all of enCore's future cash flows, results of operation, financial condition and prospects. The plans are developed based on, among other things, mining experience, reserve estimates, assumptions regarding ground conditions and physical characteristics or ores (such as hardness and presence or absence of certain metallurgical characteristics) and estimated rates and costs of production. Actual production may vary from estimates for a variety of reasons, including risks and hazards of the types discussed above, and as set out below, including:

- actual Ore mined varying from estimates in grade, tonnage, and metallurgical and other characteristics;
- mining dilution;
- ventilation and adverse temperature levels underground;
- accidents;
- equipment failures;
- natural phenomena such as inclement weather conditions, floods, blizzards, droughts, rockslides and earthquakes;
- encountering unusual or unexpected geological conditions;
- changes in power costs and potential power shortages;
- shortages of principal supplies needed for operation, including explosives fuels, chemical reagents, water, equipment parts and lubricants;
- strikes and other actions by labor at unionized locations; and
- regulatory restrictions imposed by government agencies.

Such occurrences could, in addition to stopping or delaying mineral extraction, result in damage to mineral properties, injury or death to persons, damage to enCore's property or the property of others, monetary losses and legal liabilities. These factors may also cause a mineral deposit that has been mined profitably in the past to become unprofitable. Estimates of production from properties not yet in production or from operations that are to be expanded are based on similar factors (including, in some instances, feasibility studies prepared by enCore's personnel and outside consultants) but it is possible that actual operating costs and economic returns will differ significantly from those currently estimated. It is not unusual in new mining operations to experience unexpected problems during the start-up phase. Delays often can occur in the commencement of production. The occurrence of any of the foregoing could have an adverse impact on enCore's future cash flow, earnings, results of operations and financial condition.

Our business relies on the use of drilling rigs operated by independent contractors to conduct exploration activities, and as such, their operating expense includes fixed costs that may not decline in proportion to decreases in rig utilization and day rates.

The independent contractors that operate drilling rigs, owned or used by the Company to conduct exploration activities on our mineral properties. Their operating expense includes all direct and indirect costs associated with the operation, maintenance and support of our drilling and related equipment, many of which are not affected by changes in day rates and some of which are not affected by utilization. During periods of reduced revenues or activity, certain of their fixed costs (such as depreciation) may not decline and often they may incur additional costs. During times of reduced utilization, reductions in costs may not be immediate as they may not be able to fully reduce the cost of their support operations in a particular geographic region due to the need to support the remaining drilling rigs in that region. Accordingly, a decline in revenues due to lower day rates or utilization may not be offset by a corresponding decrease in drilling services and solutions expense, which could have a material adverse effect on their ability to conduct drilling operations on the behalf of the Company that can have a material adverse effect on our business, financial condition and results of operations.

Shortages of drilling contractors, drilling supplies or other key materials could adversely affect our operations.

The drilling services and solutions business is highly cyclical. During periods of increased demand for drilling services and solutions and periods of supply chain disruption, delays in availability and shortages of drilling contractors and drilling supplies can occur, and it can impact our ability to execute our exploration activities according to our business plans. Additionally, suppliers may seek to increase prices for equipment, supplies, and services, which we are unable to pass through to our customers. Further, certain key rig components, parts and equipment are also either purchased from, fabricated or serviced by a limited number of vendors, which, in some cases, may be thinly capitalized and disproportionately affected by any loss of business, downturn in the energy industry, supply chain disruptions, or reduction or availability of credit. The failure of one or more third-party suppliers, manufacturers or service providers to provide equipment, components, parts or services, whether due to capacity constraints, labor shortages or other labor-related difficulties, production or delivery disruptions, price increases, quality control issues, recalls or other decreased availability of parts and equipment, is beyond our control and could materially disrupt our operations or result in the delay, renegotiation or cancellation of drilling contracts, thereby causing a loss of contract drilling backlog and/or revenues to us, as well as an increase in operating costs. If we are not able to effectively manage these disruptions and delays in the future, they could have a material adverse effect on our business, financial condition and results of operations.

No assurance can be given that estimates of commodity prices used in preliminary economic assessment will actually be realized.

The estimates of uranium prices used in S-K 1300 technical reports are based on conditions prevailing at the time of the writing of such reports. Conditions can change significantly over relatively short periods of time and, as such, there can be no assurance that the estimates of the price of uranium used in the S-K 1300 technical reports will actually be realized. Changes in the uranium price could have a significant impact on the viability of enCore's mineral projects and an adverse impact on enCore's future cash flows, earnings, results of operations and financial condition.

Projects may not advance or achieve production if key permits are not obtained or retained.

The advancement of mineral properties through exploration to commercial operation normally requires securing and maintaining key permits and/or licenses (collectively, the "permits") from regulatory or governmental authorities. While enCore puts its reasonable best efforts into securing the permits necessary to advance its properties according to the policies and guidelines applicable to each permit, approval of permits rests solely with the governing agency and is outside of enCore's control. In addition to the statutory and regulatory processes, there are other intangible factors, such as limited agency staffing due to budgetary and staff turnover that can impact permit and license reviews and approvals.

The requirements for obtaining a RML for the Company's mineral properties in the United States allows for public participation. Third parties may object to the issuance of RMLs and/or permits required by the Company, which may significantly delay the Company's ability to obtain an RML and/or permit. Also, insufficient or insufficiently trained staffing at regulatory agencies may delay the issuance of required permits and licenses. Generally, public objections can be overcome through the procedures set forth in the applicable permitting legislation; however, significant financial resources and managerial resources are required through this process. In addition, the various regulatory agencies must allow and fully consider the public objections/comments according to such procedures set out in the applicable legislation and there can be no assurance that the Company will be successful in obtaining an RML and/or permit, which could have a material adverse effect on the viability of a project.

Finalization of the state permitting process for the Dewey Burdock Project is subject to hearings with public participation. If the state permits are not issued in a timely manner, or at all, it could have a material adverse impact on the Company's financial performance, cash flows and results of operations. In addition, the Company will have to assess whether an impairment allowance is necessary, which, if required, could be material. There can be no guarantee that enCore will succeed in obtaining the permits necessary to advance its projects, and a failure to obtain necessary permits or retain permits that have been granted may result in an inability to realize any benefit from its exploration or development activities on its properties.

Native American tribes may be involved in the permitting process, which could cause delays or increased expenses.

None of the Company's mineral properties are located within the boundaries of Native American lands or other property interests that are controlled or owned by Native Americans under the jurisdiction of the United States federal government. However, under Federal legislation, historic cultural properties of religious significance that can be identified are to be avoided or activities are to be mitigated such that the essential nature of the properties is not lost to a culture. Throughout the western United States, Native American tribes have had historical relationships with properties that are now owned by private parties, the federal government or state governments. In any federal permitting action on these properties, the agency involved is required to make an effort to communicate with Native American tribes to determine any areas of traditional cultural significance, which involves "government to government" discussions with the potentially affected Native American tribes; therefore, delays in permitting may occur through this process. In the event that traditional cultural properties are identified within a project area, the Company and the agency must determine the best method of development to ensure that disturbances are minimized or mitigated, which could be costly and have an adverse impact on enCore's future cash flows earnings, results of operations and financial condition.

Opposition to mining may disrupt our business activities.

In recent years, governmental agencies, non-governmental organizations, individuals, communities and courts have become more vocal and active with respect to their opposition to certain mining and business activities, including with respect to production and uranium recovery at our facilities. This opposition may take on forms such as road blockades, vandalism, threats and/or slander, applications for injunctions seeking to cease certain construction, development, extraction, mining and/or milling or recovery activities, refusals to grant access to lands or to sell lands on commercially viable terms, lawsuits for damages or to revoke or modify licenses and permits, issuances of unfavorable laws and regulations, changes in regulatory attitudes and interpretations and other rulings contrary to or otherwise harming our interests. These actions can occur in response to current activities or in respect of mines or facilities that are decades old. In addition, these actions can occur in response to our activities or the activities of other unrelated entities. Opposition to our activities may also result from general opposition to nuclear energy and mining. Opposition to our business activities are beyond our control. Any opposition to our business activities may cause a disruption to our business activities and may result in increased costs and delays, which could have a material adverse effect on our business and financial condition.

Permits received are subject to expiration and may not be able to obtain, maintain or amend rights, authorizations, licenses, permits or consents required for our operations.

Our exploration and mining activities are dependent upon the grant of appropriate rights, authorizations, licenses, permits and consents, as well as continuation and amendment of these rights, authorizations, licenses, permits and consents already granted, which may be granted for a defined period of time, or may not be granted or may be withdrawn or made subject to limitations. There can be no assurance that all necessary rights, authorizations, licenses, permits and consents will be granted to us, or that authorizations, licenses, permits and consents already granted will not be withdrawn or made subject to limitations.

Permits granted by the jurisdictions in which enCore operates are typically issued with an expiry date requiring enCore to undertake certain activities within a given time frame in order for the permit to remain valid. While enCore makes every

reasonable attempt to satisfy the terms and conditions of the permits it is granted, there can be no assurance that unforeseen circumstances may prevent the Company from doing so, and permits received may expire, which could have an adverse impact on enCore's future cash flows, earnings, results of operations and financial condition.

The title to our mineral property interests may be challenged.

enCore has investigated its rights to explore and extract minerals from all of its material properties and, to the best of its knowledge, those rights are in good standing. No assurance can be given, however, that enCore will be able to secure the grant or the renewal of existing mineral rights and tenures on terms satisfactory to it, or that governments in the jurisdictions in which enCore operates will not revoke or significantly alter such rights or tenures or that such rights or tenures will not be challenged or impugned by third parties, including local governments, aboriginal peoples or other claimants. Although enCore is not currently aware of any existing title uncertainties with respect to any of its material properties, there is no assurance that such uncertainties will not result in future losses or additional expenditures, which could have an adverse impact on enCore's future cash flows, earnings, results of operations and financial condition.

The procurement of mining interests and retaining skilled employees is highly competitive.

The Company competes with other mining companies and individuals for capital, mining interests on exploration properties and undeveloped lands, acquisitions of Mineral Resources and reserves and other mining assets. The Company also competes with other mining companies to attract and retain key executives and employees. There can be no assurance that the Company will continue to be able to compete successfully with its competitors in acquiring such properties and assets or in attracting and retaining skilled and experienced employees. The mining industry has been impacted by increased worldwide demand for critical resources such as input commodities, drilling equipment, tires and skilled labor, and these shortages have caused unanticipated cost increases and delays in delivery times, thereby impacting operating costs, capital expenditures and production schedules.

The Company may be at a competitive disadvantage due to the fact that many of the Company's competitors have greater financial resources to source mineral properties and attract and retain key executives and employees. Accordingly, there can be no assurance that the Company will be able to compete successfully.

The uranium industry is highly competitive, and we may not be successful in acquiring additional contracts and projects.

The national and international uranium industry is highly competitive. enCore intends to market uranium to utilities in direct competition with supplies available from a relatively small number of mining companies, from excess inventories, including inventories made available from the decommissioning of nuclear weapons, from reprocessed uranium and plutonium derived from used reactor fuel and from the use of excess enrichment capacity to re-enrich depleted uranium tails. Our competition includes larger, more established companies with longer operating histories that not only explore for and produce uranium but also market uranium and other products on a regional, national or worldwide basis. Any failure in the expected level of demand for our uranium to materialize as a result of competition could have a material adverse effect on the Company's business, results of operations, financial condition, cash flow and liquidity.

Nuclear energy competes with other sources of energy and is subject to public acceptance of nuclear energy as a means of generating electricity.

Nuclear energy competes with other sources of energy, including oil, natural gas, coal and hydroelectricity. These other energy sources are to some extent interchangeable with nuclear energy, particularly over the longer term. Sustained lower prices of oil, natural gas, coal and hydro-electricity may result in lower demand for uranium concentrates, which could have a material adverse effect on its business, results of operations, financial condition, cash flows and liquidity. Technical advances in, and government support and subsidies for, renewable energy sources could make these forms of energy more viable and have a greater impact on nuclear fuel demands.

Furthermore, growth of the uranium and nuclear power industry will depend upon continued and increased acceptance of nuclear technology as a means of generating electricity. Because of unique political, technological and environmental factors that affect the nuclear industry, the industry is subject to public opinion risks which could have an adverse impact on the demand for nuclear power and increase the regulation of the nuclear power industry. The nuclear incident that occurred in Japan in March 2011 had significant and adverse effects on both the nuclear and uranium industries. If another nuclear incident were to occur, it could impact the continuing acceptance of nuclear energy and the future prospects for nuclear power generation, including causing governments of certain countries to further increase regulation for the nuclear industry, reduce or abandon current reliance on nuclear power or reduce or abandon existing plans for nuclear power

expansion. Any of the foregoing has the potential to reduce current and/or future demand for nuclear power, resulting in lower demand for uranium and lower market prices for uranium, which could have a material adverse effect on enCore's business, results of operations, financial condition, cash flows and liquidity.

The Company's operations are sensitive to the market price of uranium, which may be volatile.

enCore's future revenues will be directly related to the prices of uranium as its revenues will be derived from uranium mining. The Company's financial condition, results of operations, earnings and operating cash flows will be significantly affected by the market price of uranium, which is cyclical and subject to substantial short and long-term price fluctuations. Among other factors, uranium prices also affect the value of the Company's resources, as well as the market price of the common shares.

Uranium prices are and will continue to be affected by numerous factors beyond enCore's control. Such factors include, among others, the demand for nuclear power; political and economic conditions in uranium producing and consuming countries such as Canada, the United States, Russia and other former Soviet Republics; reprocessing of used reactor fuel and the re-enrichment of depleted uranium tails; sales of excess civilian and military inventories (including from the dismantling of nuclear weapons) by governments and industry participants; and production levels and costs of production in countries such as Russia and former Soviet republics, Africa and Australia; international wars or conflicts (including Russia's military invasion of Ukraine); geopolitical developments (including trading and tariff arrangements, sanctions and cybersecurity attacks), terrorism, natural disasters and public health epidemics or pandemics. The extent and duration of such events and resulting market disruptions cannot be predicted but could be substantial and could magnify the impact of other risks to the Company. These and other similar events could adversely affect the United States and foreign financial markets and lead to increased market volatility.

If, after the commencement of commercial production, the uranium price falls below the costs of production at enCore's mines for a sustained period, it may not be economically feasible to continue production at such sites. This would materially and adversely affect production, profitability and enCore's results of operation and financial position. A decline in the uranium price may also require enCore to write down its Mineral Resources, which would have a material adverse effect on its earnings and profitability.

Hedging activities may not be successful.

enCore does not hedge any of its future uranium extraction but may engage in hedging activities in the future. Hedging activities would be intended to protect enCore from the fluctuations of the price of uranium and to minimize the effect of declines in the uranium price on results of operations for a period of time. Although hedging activities may protect enCore against lower uranium prices, they may also limit the price that can be realized on uranium that is subject to forward sales and call options where the market price of uranium exceeds the uranium price in a forward sale or call option contract.

We may need additional financing in connection with the implementation of our business and strategic plans from time to time.

The exploration, construction, development and acquisition of mineral properties and the ongoing operation of mines and other facilities requires a substantial amount of capital and may depend on our ability to obtain financing through joint ventures, debt financing, equity financing or other means. We may accordingly need further capital in order to take advantage of further opportunities or acquisitions. Our financial condition, general market conditions, volatile uranium market, volatile interest rates, legal claims against us, a significant disruption to our business or operations, or other factors may make it difficult to secure financing necessary for the expansion of mining activities or to take advantage of opportunities for acquisitions. Further, volatility in the credit markets may increase costs associated with debt instruments due to increased spreads over relevant interest rate benchmarks, or may affect our ability, or the ability of third parties we seek to do business with, to access those markets.

Continued volatility in equity markets, specifically including energy and commodity markets, may increase the costs associated with equity financings due to a low share price and may create the potential need for us to offer higher discounts and other value. There is no assurance that we will be successful in obtaining required financing as and when needed on acceptable terms, if at all.

We may be subject to litigation and other legal proceedings arising in the normal course of business and may be involved in disputes with other parties in the future which may result in litigation.

The Company may be subject to litigation and other legal proceedings arising in the normal course of business and may be involved in disputes with other parties in the future, which may result in litigation. The causes of potential future litigation and legal proceedings cannot be known and may arise from, among other things, business activities, environmental laws, permitting and licensing activities, volatility in share prices or failure to comply with disclosure obligations. The results of litigation and proceedings cannot be predicted with certainty and may include potential injunctions pending the outcome of such litigation and proceedings. If the Company is unable to resolve these disputes favorably, it may have a material adverse impact on the Company's financial performance, cash flow and results of operations. Securities class-action litigation often has been brought against companies in periods of volatility in the market price of their securities and following major corporate transactions or mergers and acquisitions. The Company may in the future be the target of similar litigation. Securities litigation could result in substantial costs and damages and divert management's attention and resources.

The uranium industry is subject to numerous stringent laws, regulations and standards, including environmental protection laws and regulations. If any changes occur that would make these laws, regulations and standards more stringent, it may require capital outlays in excess of those anticipated or cause substantial delays, which would have a material adverse effect on our operations.

The current and future mining operations and exploration and development activities of enCore, particularly uranium mining, are subject to laws and regulations at the federal, state and local level governing worker health and safety, employment standards, mine development, mine safety, exports, imports, taxes and royalties, waste disposal, toxic substances, land claims of indigenous peoples, protection and remediation of the environment, mine decommissioning and reclamation, transportation safety and emergency response and other matters. Each jurisdiction in which enCore has properties regulates mining activities. It is possible that future changes in applicable laws and regulations or changes in their enforcement or regulatory interpretation could result in changes in legal requirements or in the terms of existing permits, licenses and approvals applicable to enCore or its projects, which could have a material and adverse impact on enCore's current mining operations or planned development projects.

enCore is also subject to various reclamation and other bonding requirements under federal, state, provincial or local air, water quality and mine reclamation rules and permits. Although enCore makes provision for reclamation costs, there is no assurance that these provisions will be adequate to discharge its obligations for these costs. Environmental and employee health and safety laws and regulations have tended to become more stringent over time. Any changes in such laws or in the environmental conditions at enCore's properties could have a material adverse effect on enCore's financial condition, cash flow or results of operations.

Failure to comply with applicable environmental and health and safety laws can result in injunctions, damages, suspension or revocation of permits and the imposition of penalties. There can be no assurance that enCore has been or will be at all times in complete compliance with such laws, regulations and permits, or that the costs of complying with current and future environmental and health and safety laws and permits will not adversely affect enCore's business, results of operations, financial condition or prospects.

Worldwide demand for uranium is directly tied to the demand for electricity produced by the nuclear power industry, which is also subject to extensive government regulation and policies, and any change in these regulations or policies may have a negative impact on enCore's business or financial condition.

Mineral exploration and the development of mines and related facilities is contingent upon governmental approvals, licenses and permits which are complex and time consuming to obtain and which, depending on the location of the project, involve multiple governmental agencies. The receipt, duration, amendment or renewal of such approvals, licenses and permits are subject to many variables outside enCore's control, including inadequate agency staff experience, inability of governmental agencies to process licenses and permits in a timely manner, reduced agency staff capacity, potential legal challenges from various stakeholders such as environmental groups, non-governmental organizations, aboriginal groups or other claimants. The costs and delays associated with obtaining necessary approvals, licenses and permits and complying with these approvals, licenses and permits and applicable laws and regulations could stop or materially delay or restrict enCore from proceeding with the development of an exploration project or the operation or further development of a mine. Any failure to comply with applicable laws and regulations or approvals, licenses or permits, even if inadvertent, could result in interruption or closure of exploration, development or mining operations, or material fines, penalties or other liabilities.

Where required, obtaining necessary permits to conduct exploration or mining operations can be a complex and time consuming process, and enCore cannot assure whether any necessary permits will be obtainable on acceptable terms, in a timely manner or at all.

Insurance may not be available to cover the gamut of risks associated with mineral exploration, development and mining.

The mining industry is subject to significant risks that could result in damage to or destruction of property and facilities, personal injury or death, environmental damage and pollution, delays in production, expropriation of assets and loss of title to mining claims. No assurance can be given that insurance to cover the risks to which enCore's activities are subject will be available at all or at commercially reasonable premiums. enCore currently maintains insurance within ranges of coverage that it believes to be consistent with industry practice for companies of a similar stage of development. enCore carries liability insurance with respect to its mineral exploration operations which includes a form of environmental liability insurance. Since insurance against environmental risks (including liability for pollution) or other hazards resulting from exploration and development activities is prohibitively expensive, enCore's insurance coverage is limited. The payment of any such liabilities would reduce the funds available to enCore. If enCore is unable to fully fund the cost of remedying an environmental problem, it might be required to suspend operations or enter into costly interim compliance measures pending completion of a permanent remedy.

We rely on contractors and experts in our operations, which could subject the Company to liability that could adversely impact the Company's operations and financial condition.

In various aspects of its operations, enCore relies on the services, expertise and recommendations of its service providers and their employees and contractors, whom often are engaged at significant expense to the Company. For example, the decision as to whether a property contains a commercial mineral deposit and should be brought into extraction will depend in large part upon the results of exploration programs and/or feasibility studies, and the recommendations of duly qualified third-party engineers and/or geologists. In addition, while enCore emphasizes the importance of conducting operations in a safe and sustainable manner, it cannot exert absolute control over the actions of these third parties when providing services to enCore or otherwise operating on enCore's properties. Any material error, omission, act of negligence or act resulting in environmental pollution, accidents or spills, industrial and transportation accidents, work stoppages or other actions could adversely affect the Company's operations and financial condition.

Extraction, capital and operating cost estimates may be inaccurate.

We prepare estimates of annual and future extraction, the attendant extraction and operational costs and required working capital for such levels of extraction, but there is no assurance that we will achieve those estimates. These types of estimates are inherently uncertain and may change materially over time. Operational cost estimates are affected by changes in extraction levels and may be affected by continuing inflation and cost-of-goods due to supply chain issues as well as the possible need to utilize a greater level of contractor services if required staffing is unavailable or cannot timely be hired and trained. Availability and consistent pricing of materials necessary in the installation of wells, surface production equipment, associated infrastructure, chemicals for processing and, expendable materials related to operations, can be variable depending on economic conditions locally and worldwide and may force changes in operations and timing of resource extraction. In addition, we rely on certain contractors related to the installation of wells and technical services associated with that installation. Their availability or cost of service can change depending on other local market conditions and may therefore affect the installation and extraction rates of mining.

Increased exposure to foreign exchange rate fluctuations may adversely affect our costs, earnings and value of some of our assets, including our common shares.

The Company maintains its accounting records and reports its financial position and results in U.S. Dollars. In addition to its listing on Nasdaq, the Company's common shares are listed for trading on the TSX-V and trades in Canadian Dollars. In addition, enCore raises funds through equity issuances which are priced in Canadian Dollars. Fluctuations in the Canadian currency exchange rate relative to the U.S. currency could significantly impact the Company, including its financial results, operations or the trading value of its securities. The price of uranium is quoted in U.S. Dollars, and a decrease in value of the U.S. Dollar would result in a relative decrease in the valuation of uranium and the associated market value from a Canadian currency perspective.

We utilize novel mining methods for production at our properties, which may not yield anticipated results.

The Company focuses on the ISR mining method for production at its properties. While studies completed to date indicate that ground conditions and the mineral resources estimated to be contained on the Company's Rosita, Dewey-Burdock, Gas Hills, Mesteña Grande and Alta Mesa ISR uranium projects, and the projects are amenable to extraction by way of ISR, actual conditions could be materially different from those estimated based on the Company's technical studies completed to-date. While industry best practices have been utilized in the development of its estimates, actual results from the

application of the ISR mining method may differ significantly. The Company will need to complete substantial additional work to further advance and/or confirm its current estimates for the use of the ISR mining method on its properties. As a result, it is possible that current estimates may not be achieved on any of the Company's mining properties, which could adversely affect the Company's operations and financial condition.

We are subject to technical innovation and obsolescence.

Requirements for our products and services may be affected by: technological changes in nuclear reactors, enrichment and used uranium fuel reprocessing. These technological changes could reduce the demand for our products and services and/or increase the supply of competitive products and services. The cost competitiveness of our operations may be impacted through the development and commercialization of other mining, milling, processing and other technologies. As a result, our competitors may adopt technological advancements that give them an advantage over the Company or that reduce the demand for the Company's products and services or make them obsolete.

Since there is no liquid public market for uranium, selling uranium may take extended periods of time and suitable purchasers may be difficult to find, which could have a material adverse effect on our financial condition.

There is no liquid public market for the sale of uranium. The uranium futures market on the Chicago Mercantile Exchange does not provide for physical delivery of uranium, only cash on settlement.

The Company may not be able to, once produced, sell uranium at a desired price level for a number of weeks or months. The pool of potential purchasers or sellers is limited, and each transaction may require the negotiation of specific provisions. Accordingly, a sale cycle may take several weeks or months to complete. If the Company determines to sell any physical uranium that it has produced, it may likewise experience difficulties in finding purchasers that are able to accept a material quantity of physical uranium.

The Company may also intend to hold physical uranium for long-term investment. During this term, the value of the Company's uranium holdings will fluctuate and accordingly the Company will be subject to losses should it ultimately determine to sell the uranium at prices lower than the acquisition cost. In addition, the Company may incur income statement losses, should uranium prices decrease or foreign exchange rates fluctuate unfavorably in future financial periods. The Company may be required to sell a portion or all of the physical uranium accumulated to fund its operations should other forms of financing not be available to fund the Company's capital requirements, which could result in losses and adversely affect the Company's operations and financial condition.

The ability to sell and profit from the sale of any eventual acquired uranium or mineral production from a property will be subject to the prevailing conditions in the applicable marketplace at the time of sale. The demand for uranium and other minerals is subject to global economic activity and changing attitudes of consumers and other end-users' demand. The inability to sell on a timely basis in sufficient quantities at favorable prices could have a material adverse effect on the Company.

Global demand for uranium is subject to government regulation and policies, including international trade restrictions.

The international nuclear fuel industry, including the supply of uranium concentrates, is relatively small compared to other minerals, and is generally highly competitive and heavily regulated.

Worldwide demand for uranium is directly tied to the demand for electricity produced by the nuclear power industry, which is also subject to extensive government regulation and policies. In addition, the international marketing of uranium is subject to governmental policies and certain trade restrictions. For example, the war in Ukraine has resulted in impacts to the nuclear fuel industries and uranium producers, through the imposition of sanctions and counter sanctions, which has an adverse effect on energy and economic markets, including the nuclear fuel industries because of the vast reliance by the United States and other nations on uranium products exported from Russia and Russian-controlled or influenced sources. In addition, the conflicts in the Middle East, and other geopolitical tensions, including between the United States and China, also make it difficult to assess and predict the impact to the economy, supply disruption, increased prices of materials, and cyber-security threats.

In general, trade agreements, governmental policies and/or trade restrictions are beyond the control of the Company and may affect the supply of uranium available for use in markets like the United States and Europe, which are currently the largest markets for uranium in the world. Similarly, trade restrictions or foreign policy have the potential to impact the ability to supply uranium to developing markets, such as China and India. If substantial changes are made to regulations

affecting the global marketing and supply of uranium, the Company's business, financial condition and results of operations may be materially adversely affected.

Imports from state-owned enterprises may continue to challenge the U.S. uranium industry.

Notwithstanding other recent favorable market events and pricing, the global uranium market continues to be characterized by production levels and sales priced in and for countries such as Russia, Kazakhstan and Uzbekistan which adversely affect the U.S. uranium production industry. China continues to expand its role in the global uranium mining markets and in the rest of the nuclear fuel cycle, including with effects felt in the U.S. Additionally, the extent of foreign inventories in some instances remains uncertain. If U.S. imports from government-subsidized production sites resume beyond demand capacity, there could be a significant negative impact to the uranium market which could adversely impact the Company's future profitability.

Possible amendments to the general mining law could make it more difficult or impossible for us to execute our business plan.

Members of the U.S. Congress have repeatedly introduced bills which would supplant or alter the provisions of the United States Mining Law of 1872, as amended (the "General Mining Law"). Such bills have proposed, among other things, to (i) either eliminate or greatly limit the right to a mineral patent; (ii) significantly alter the laws and regulations relating to uranium mineral development and recovery from unpatented and patented mining claims; (iii) impose a federal royalty on production from unpatented mining claims; (iv) impose time limits on the effectiveness of plans of operation that may not coincide with mine or facility life; (v) impose more stringent environmental compliance and reclamation requirements on activities on unpatented mining claims; (vi) establish a mechanism that would allow states, localities and Native American tribes to petition for the withdrawal of identified tracts of federal land from the operation of the US. General Mining Law; and (vii) allow for administrative determinations that mining or similar activities would not be allowed in situations where undue degradation of the federal lands in question could not be prevented. If enacted, such legislation could change the cost of holding unpatented mining claims and could significantly impact our ability to develop locatable Mineral Resources on our patented and unpatented mining claims. Although it is impossible to predict at this point what any legislated royalties might be, enactment could adversely affect the potential for construction and development and the economics of existing operating mines and facilities. Passage of such legislation could adversely affect our financial performance.

The EPA has in recent years announced an intention to propose new rules that, if promulgated, could result in increases in mine surety arrangements to cover currently non-existing and unidentified potential future environmental costs, which could severely impact or render infeasible many existing or prospective mining operations. The EPA dropped this proposal after considering comments received during the public participation process. Nevertheless, there is a risk that similar regulations could be proposed in the future, which could have significant impacts on the Company and the mining industry as a whole.

Our operations on U.S. federal lands may be impacted by mineral withdrawals or the designation of national monuments by the U.S. President or government, either of which could have significant impacts on the Company and our operations, as well as by other factors.

Mining claims on U.S. federal lands are subject to mineral withdrawals by the federal government or the designation of national monuments by the President of the U.S. under the Antiquities Act of 1906. In both cases, the withdrawal or the designation of a national monument withdraws the area from location and entry under the General Mining Law (defined below), subject to valid existing rights. What this means is that no new mining claims may be filed on the withdrawn or designated lands and no new plans of operations may be approved, other than plans of operations on mining claims that were valid at the time of withdrawal or designation and that remain valid at the time of plan approval. Whether or not a mining claim is valid must be determined by a mineral examination conducted by BLM. The mineral examination, which involves an economic evaluation of a project, must demonstrate the existence of a locatable mineral resource and that the mineral resource constitutes discovery of a valuable mineral deposit. Any future withdrawal of mineral lands from location and entry or future designation of additional national monuments has the potential to prevent further development on exploration stage claims held by the Company in the affected area as well as the potential for the Company to lose the ability to continue to develop mining operations on other claims in the affected area if a mineral examination indicates the deposit is uneconomical and that the claim is not valid, either of which could have significant impacts on the Company.

The risks of exchanges of state-owned lands in mineral withdrawal areas or national monuments for federal lands outside the withdrawal area or national monument but that are within the boundaries of and affect any of our properties, or similar actions, could adversely impact our affected properties or our ability to operate our affected properties.

There are risks associated with the Company's joint venture operations and projects.

Although the Company holds a majority interest in joint venture formed to hold the Alta Mesa Project, enCore faces risks that major decisions affecting the Alta Mesa Project may require the consent of or agreement with Boss pursuant to the joint venture agreement.

From time to time, the Company may enter into other joint venture or shared ownership arrangements with third parties to develop and/or operate its projects.

The success and timing of these operations and projects depend on a number of factors that may be outside our control, including the financial resources of our partners and the objectives and interests of our partners. While joint venture partners may generally reach consensus regarding the direction and operation of the operation or project, there are no assurances that this will always be the case or that future demands and expectations will continue to align. Failure of joint venture partners to agree on matters requiring consensus may lead to development or operational delays, failure to obtain necessary permits or approvals in an efficient manner or at all, remedies under dispute resolution mechanisms, or the inability to progress with production at the relevant operation or development of the relevant project in accordance with expectations or at all, which could materially affect the operation or development of such projects or operations and our business and financial condition.

Risks Related to Taxation

If the Company is characterized as a passive foreign investment company, U.S. Holders may be subject to adverse U.S. federal income tax consequences

Prospective U.S. investors should be aware that they could be subject to certain adverse U.S. federal income tax consequences in the event that the Company is classified as a "passive foreign investment company" (a "PFIC") for U.S. federal income tax purposes. The determination of whether a corporation is a PFIC for a taxable year depends, in part, on the application of complex U.S. federal income tax rules, which are subject to differing interpretations, and the determination will depend on the composition of the corporation's income, expenses and assets from time to time and the nature of the activities performed by the corporation's officers and employees. Based on an analysis of the Company's activities and income and assets, the Company believes that it was a PFIC for its taxable year ended December 31, 2023, and may continue to be classified as a PFIC for the taxable year ended December 31, 2024, the current taxable year and the foreseeable future. A prospective investor should consult its own tax advisor regarding the likelihood and consequences of the Company being treated as a PFIC for U.S. federal income tax purposes, including the advisability of making certain elections that may mitigate certain possible adverse U.S. federal income tax consequences but that may result in an inclusion of gross income without receipt of such income.

We are subject to Canadian tax on our worldwide income.

We are deemed to be a resident of Canada for Canadian federal income tax purposes by virtue of being organized under the laws of British Columbia, a province of Canada. Accordingly, we are subject to Canadian taxation on our worldwide income, in accordance with the rules set forth in the Income Tax Act (Canada) (the "Tax Act") generally applicable to corporations residing in Canada.

Dividends, if ever paid, on the common shares are subject to Canadian withholding tax.

It is currently not anticipated that we will pay any dividends on our common shares in the foreseeable future. Dividends received by shareholders who are residents of the U.S. ("U.S. Holders") will be subject to Canadian withholding tax. Any dividends may not qualify for a reduced rate of withholding tax under the U.S.-Canada Treaty. For U.S. federal income tax purposes, a U.S. Holder may elect for any taxable year to receive either a credit or a deduction for all foreign income taxes paid by the holder during the year. Dividends paid on the common stock will be treated as foreign-source income, and generally will be treated as "passive category income" or "general category income" for U.S. foreign tax credit purposes. Subject to certain limitations, a U.S. Holder should be able to take a deduction for the U.S. Holder's Canadian tax paid, provided that the U.S. Holder has not elected to credit other foreign taxes during the same taxable year.

Dividends received by Non-U.S. Holders who are not residents of Canada for purposes of the Tax Act will be subject to Canadian withholding tax. These dividends may qualify for a reduced rate of Canadian withholding tax under any income tax treaty otherwise applicable to our shareholders, subject to examination of the relevant treaty.

Each of our shareholders should seek tax advice, based on such shareholder's particular facts and circumstances, from an independent tax advisor.

Changes in tax laws may affect us and our shareholders.

There can be no assurance that our Canadian and U.S. federal income tax treatment or an investment in us will not be modified, prospectively or retroactively, by legislative, judicial or administrative action, in a manner adverse to us or our shareholders.

Risks Related to enCore's Common Shares

The issuance of additional common shares may dilute shareholders' interest in the Company.

enCore may require additional funds to fund its exploration and development programs and potential acquisitions. If enCore raises additional funding by issuing additional equity securities, such financing may substantially dilute the interests of its shareholders.

enCore may issue additional common shares in the future pursuant to proposed acquisitions described herein and on the exercise of its outstanding stock options and warrants.

Sales of substantial amounts of enCore's common shares, or the availability of such common shares for sale, could adversely affect the prevailing market prices for enCore's securities. A decline in the market prices of enCore's securities could impair its ability to raise additional capital through the sale of new common shares should enCore desire to do so.

The market price for common shares cannot be assured and subject to volatility.

Securities markets have experienced a high level of price and volume volatility, and the market price of securities of many companies has experienced wide fluctuations which have not necessarily been related to the operating performance, underlying asset values or prospects of such companies.

In the past, following periods of volatility in the market price of a company's securities, shareholders have often instituted class action securities litigation against those companies. Such litigation, if instituted, could result in substantial costs and diversion of management attention and resources, which could significantly harm enCore's profitability and reputation.

enCore has never paid dividends and does not currently intend to do so in the foreseeable future. If our share price does not appreciate, our investors could potentially lose on their investment in our common shares.

enCore has never paid cash dividends on its common shares. enCore currently intends to retain its future earnings, if any, to fund the development and growth of its business, and does not anticipate paying any cash dividends on its common shares for the foreseeable future. As a result, shareholders will have to rely on capital appreciation, if any, to earn a return on investment in any common shares in the foreseeable future. Furthermore, enCore may in the future become subject to contractual restrictions on, or prohibitions against, the payment of dividends.

Our common shares are listed on Nasdaq, which subjects us to various listing standards, noncompliance of which could result in the delisting of our common shares, which could result in lower trading volumes and liquidity in the United States.

Our common shares began trading on Nasdaq on January 2, 2024. Continued listing of a security on Nasdaq is conditioned upon compliance with various listing standards. Failure to comply with Nasdaq's continued listing standards could result in Nasdaq delisting our Common Shares resulting in our common shares trading in the less liquid over-the-counter market in the United States.

If Nasdaq delists our common shares, investors may face material adverse consequences including, but not limited to, a lack of trading market for our securities in the United States, reduced liquidity, decreased analyst coverage of our securities, and an inability for us to obtain additional financing to fund our operations.

Moreover, even to the extent our common shares remain listed on Nasdaq, there can be no assurance an active and liquid trading market for our common shares will develop or be maintained.

General Risks

Global financial conditions and risks could materially impact our ability to raise equity or obtain debt and impact global supply chains, which could adversely impact the Company's operations and financial condition.

The development and ongoing operation of mines requires a substantial amount of capital prior to the commencement of, and in connection with, the production of uranium. Such capital requirements relate to the costs of, among other things, acquiring mining rights and properties, obtaining government permits, exploration and delineation drilling to determine the underground configuration of a deposit, designing and constructing the mine and processing facilities, purchasing and maintaining mining equipment and complying with financial assurance requirements established by various regulatory agencies for the future restoration and reclamation activities for each project. There is a risk that cash flow from operations will be insufficient to meet current and future obligations, fund development and construction projects, and that additional outside sources of capital will be required. The volatility of global capital markets, including the general economic slowdown in the mining sector, has generally made the raising of capital by equity or debt financing more difficult. The Company may be dependent upon capital markets to raise additional financing in the future. As such, the Company is subject to liquidity risks in meeting its operating expenditure requirements and future development cost requirements in instances where adequate cash positions are unable to be maintained or appropriate financing is unavailable. If the Company is unable to raise equity or obtain loans and other credit facilities in the future and on terms favorable to the Company, these levels of volatility persist or there is a further economic slowdown, the Company's operations, the Company's ability to raise capital and the trading price of the Company's securities could be adversely impacted.

As the Company's operations expand and reliance on global supply chains increases, the impact of pandemics, significant geopolitical risk and conflict globally may have a sizeable and unpredictable impact on the Company's business, financial condition and operations. Russia's invasion of Ukraine, including the global response to Russia as it relates to sanctions, trade embargos and military support, have resulted in significant uncertainty as well as economic and supply chain disruptions. Should such global conflicts and responses go on for an extended period of time or should other geopolitical disputes and conflicts and responses thereto emerge in other regions that produce uranium or other energy, this could result in material adverse effects to the Company.

General inflationary pressures may impact the Company's costs and affect our results of operations.

Inflationary pressure may also affect Company's labor, commodity, and other input costs, which could affect the Company's financial condition. Operational costs may be affected by continuing inflation and cost-of-goods due to supply chain issues as well as the possible need to utilize a greater level of contractor services if required staffing is unavailable or cannot timely be hired and trained. The resulting impact of this is that the Company faces higher costs for key inputs required for its operations, which may be directly through higher transportation costs, as well as indirectly through higher costs of products that rely on energy, which could result in material adverse effects to the Company.

We are dependent on information technology systems, which are subject to certain risks, including cybersecurity risks and data leakage risks associated with implementation and integration.

The Company's operations depend upon the availability, capacity, reliability and security of its information technology ("IT") infrastructure, and its ability to expand and update this infrastructure as required, to conduct daily operations. enCore relies on various IT systems in all areas of its operations, including financial reporting, contract management, exploration and development data analysis, human resource management, regulatory compliance and communications with employees and third parties.

These IT systems could be subject to network disruptions caused by a variety of sources, including computer viruses, security breaches and cyber-attacks, as well as network and/or hardware disruptions resulting from incidents such as unexpected interruptions or failures, natural disasters, fire, power loss, vandalism and theft. The Company's operations also depend on the timely maintenance, upgrade and replacement of networks, equipment, IT systems and software, as well as pre-emptive expenses to mitigate the risks of failures.

The ability of the IT function to support the Company's business in the event of any such occurrence and the ability to recover key systems from unexpected interruptions cannot be fully tested. There is a risk that, if such an event actually occurs, the Company's continuity plans may not be adequate to immediately address all repercussions of the disaster. In the event of a disaster affecting a data center or key office location, key systems may be unavailable for a number of days, leading to inability to perform some business processes in a timely manner. As a result, the failure of enCore's IT systems

or a component thereof could, depending on the nature of any such failure, adversely impact the Company's reputation and results of operations.

Although to date the Company has not experienced any material losses relating to cyber-attacks or other information security breaches, there can be no assurance that the Company will not incur such losses in the future. Unauthorized access to enCore's IT systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to the Company's business activities or its competitive position. Further, disruption of critical IT services, or breaches of information security, could have a negative effect on the Company's operational performance and its reputation. The Company's risk and exposure to these matters cannot be fully mitigated because of, among other things, the evolving nature of these threats. As a result, cyber security and the continued development and enhancement of controls, processes and practices designed to protect systems, computers, software, data and networks from attack, damage or unauthorized access remain a priority.

The Company applies technical and process controls in line with industry-accepted standards to protect information, assets and systems; however, these controls may not adequately prevent cyber-security breaches. There is no assurance that the Company will not suffer losses associated with cyber-security breaches in the future and may be required to expend significant additional resources to investigate, mitigate and remediate any potential vulnerabilities. As cyber threats continue to evolve, the Company may be required to expend additional resources to continue to modify or enhance protective measures or to investigate and remediate any security vulnerabilities.

Our business is subject to the U.S. Foreign Corrupt Practices Act and other extraterritorial and national anti-bribery laws and regulations, a breach or violation of which could lead to substantial sanctions and civil and criminal prosecution, as well as fines and penalties, litigation, loss of licenses or permits and other collateral consequences and reputational harm.

The Company is subject to anti-bribery and anti-corruption laws, including the United States Foreign Corrupt Practices Act of 1977, as amended and the Corruption of Foreign Public Officials Act (Canada). Failure to comply with these laws could subject the Company to, among other things, reputational damage, civil or criminal penalties, other remedial measures and legal expenses which could adversely affect the Company's business, results from operations, and financial condition. It may not be possible for the Company to ensure compliance with anti-bribery and anti-corruption laws in every jurisdiction in which its employees, agents, sub-contractors or joint venture partners are located or may be located in the future.

The Company is a public issuer in both the United States and Canada. The board of directors (the "Board") and management must devote time and resources to compliance initiatives, corporate governance practices and securities rules and regulations that impose various requirements on both Canadian and U.S. public companies. These additional costs and management attention could negatively impact our business, financial condition and results of operations.

As a public issuer in Canada, the Company is subject to the reporting requirements and rules and regulations under Canadian securities laws and the rules of TSX-V. As a public issuer in the United States, the Company is also subject to the rules and regulations of the SEC and Nasdaq and the reporting requirements of the Exchange Act. Application of both existing or new U.S. or Canadian regulatory requirements may have adverse consequences on our ability to issue securities to raise capital or as consideration for acquisitions.

As a public company, there are costs associated with legal, accounting and other expenses related to regulatory compliance in Canada as well as compliance with the U.S. securities legislation and the rules and policies of Canadian Securities Administrators, TSX-V, the SEC and Nasdaq require reporting and listed companies to, among other things, adopt corporate governance and related practices, and to continuously prepare and disclose material information, all of which add to a company's legal and financial compliance costs. Complying with these U.S. and Canadian statutes, regulations and requirements may occupy a significant amount of time of the Board and management.

Our management must devote substantial time and cost to the establishment, modification and maintenance of effective internal controls required by Section 404(a) of the Sarbanes-Oxley Act of 2002 ("SOX"). These requirements take additional time resources and increase our legal and financial compliance costs. If we are unable to maintain effective internal controls, our ability to produce timely and accurate financial statements could be impaired, investors could lose confidence in our financial information and the price of our common shares could decline.

Prior to becoming a U.S. reporting company on January 1, 2024, we did not have to comply with Section 404(a) of SOX regarding internal control over financial reporting. As a domestic issuer, we are now required to maintain effective disclosure controls and procedures and internal controls over financial reporting. Beginning with this Annual Report, our management is required to furnish a report on our internal controls over financial reporting. In addition, on an annual basis,

our independent registered public accounting firm is required, pursuant to Section 404(b) of SOX, to attest to the effectiveness of our internal control over financial reporting and we will be required to include such attestation in our Annual Reports.

Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with U.S. GAAP. The rules governing the standards that must be met for our management to assess our internal control over financial reporting are complex and require significant documentation, testing and possible remediation. These requirements require additional time resources and increase our legal and financial compliance costs. In this regard, we will need to (i) continue to dedicate internal resources and potentially engage outside consultants, (ii) maintain an on-going work plan to assess and document the adequacy of internal control over financial reporting, (iii) continue steps to improve control processes, as appropriate, (iv) validate, through testing, that controls are functioning as documented, and (v) maintain a continuous reporting and improvement process for internal control over financial reporting. We cannot predict or estimate the amount of time resources and additional costs we may incur or the impact and timing of such use of resources and costs. We may encounter problems or delays in implementing any changes necessary to make a favorable assessment of our internal controls over financial reporting.

Any testing by us conducted in connection with Section 404 of SOX, may reveal deficiencies in our internal controls over financial reporting that are deemed to be material weaknesses that may require prospective or retrospective changes to our consolidated financial statements, or identify other areas for further attention or improvement. Inferior internal controls could impair our ability to produce timely and accurate financial statements and cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our common shares.

Despite the efforts we are undertaking, there is a risk that we will not be able to conclude, within the prescribed time frame or at all, that our internal control over financial reporting is effective as required by Section 404 of SOX. If within the prescribed time frame, we cannot favorably assess the effectiveness of our internal control over financial reporting, or our independent registered public accounting firm is unable to provide an unqualified attestation report on our internal controls, investors could lose confidence in our financial information and the price of our common shares could decline.

We have identified material weaknesses in our internal controls over financial reporting. If we are unable to remediate these material weaknesses, or if we experience additional material weaknesses in the future or otherwise fail to maintain an effective system of internal controls, we may not be able to accurately or timely report our financial results, in which case our business may be harmed and, investors may lose confidence in the accuracy and completeness of our financial reports, and as a result, the price of our common shares may be adversely affected.

In the course of its assessment of the effectiveness of our internal control over financial reporting, our management identified material weaknesses in our internal control over financial reporting as of December 31, 2024 (see Item 9A to this Annual Report for more information). A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. The material weaknesses are described in more detail in this Report under "*Item 9A. Controls and Procedures*." As a result of these material weaknesses, our management concluded that our internal control over financial reporting and our disclosure controls and procedures were ineffective at December 31, 2024. Management has implemented a remediation plan, detailed in Item 9A of this Annual Report, as of the date of this Annual Report. If we fail to remediate the material weaknesses or experience additional material weaknesses in the future or fail to otherwise maintain effective financial reporting systems and processes, we may be unable to accurately and timely report our financial results or comply with the requirements of being a public company, which could cause investors to lose confidence in our financial information and the price of our common shares could decline. We cannot assure you that the measures we have taken to date, and are continuing to implement, will be sufficient to remediate the material weaknesses. Moreover, we cannot be certain that we will not in the future have additional material weaknesses in our internal control over financial reporting, or that we will successfully remediate any that we find.

The SEC's disclosure requirements for Mineral Reserves and Mineral Resources, as codified in Subpart 1300 of Regulation S-K 1300, create ambiguity for issuers required to comply with both the requirements of S-K 1300 and NI 43-101, and may result in increased compliance costs for the Company.

S-K 1300, as promulgated by the SEC and effective starting in 2021, required that the Company disclose specific information related to its material mining operations, including its Mineral Resources and Mineral Reserves. While S-K 1300 is substantively the same as NI 43-101, it is relatively new compared to NI 43-101 and, thus, remains subject to unknown interpretations that could require the Company to incur substantial costs associated with compliance. Where substantive disclosure in one regulatory scheme is more restrictive/stringent than in the other, the Company opted to take the more restrictive/stringent approach in its technical reports. NI 43-101 has a prescribed format, whereas S-K 1300 does

not; as such, the Company's technical reports follow the formatting requirements of NI 43-101. Any further revisions to, or interpretations of, S-K 1300 or NI 43-101 could result in the Company incurring unforeseen costs associated with compliance, both in the U.S. and in Canada.

United States investors may not be able to obtain enforcement of civil liabilities against the Company.

The enforcement by investors of civil liabilities under the United States Federal or State securities laws may be affected adversely by the fact that the Company is governed by the BCBCA. It may not be possible for investors to effect service of process within the United States on certain of its directors and officers or enforce judgments obtained in the United States courts against the Company or certain of the Company's directors and officers based upon the civil liability provisions of United States federal securities laws or the securities laws of any state of the United States. There is some doubt as to whether a judgment of a United States court based solely upon the civil liability provisions of United States federal or state securities laws would be enforceable in Canada against the Company or its directors and officers. There is also doubt as to whether an original action could be brought in Canada against the Company or its directors and officers to enforce liabilities based solely upon United States federal or state securities laws.

Changes in accounting rules and other policy or regulatory changes could occur at any time and could impact us in significantly negative ways that we are unable to predict or protect against.

The SEC, Financial Accounting Standards Board and other regulatory bodies that establish the accounting rules applicable to us have proposed or enacted a wide array of changes to accounting rules over the last several years. Moreover, in the future, these regulators may propose additional changes that we do not currently anticipate. Changes to accounting rules that apply to us could significantly impact our business or our reported financial performance in negative ways that we cannot predict or protect against. We cannot predict whether any changes to current accounting rules will occur or what impact any codified changes will have on our business, results of operations, liquidity or financial condition.
The recent change in the U.S. Presidential Administration and changes in Congress could result in significant policy changes or regulatory uncertainty in our industry. While it is not possible to predict when and whether significant policy or regulatory changes would occur, any such changes on the federal, state or local level could significantly impact, among other things, our operating expenses, our ability to obtain the required licenses and permits in a timely manner, the availability of financing, interest rates, the economy and the geopolitical landscape. To the extent that the new government administration takes action by proposing and/or passing regulatory policies that could have a negative impact on our industry, such actions may have a material adverse effect on our business, results of operations, liquidity and financial condition.

Our proprietary data, technology and intellectual property may be compromised or lost, which could result in decreased competitive advantage and/or loss to the value of such assets.

With the ever-increasing reliance on technology throughout our operations, including developments of proprietary technology and intellectual property by the Company and/or it consultants, risks of theft, appropriation or other loss of such technology and assets and/or our proprietary data pose a risk to our competitive advantage and business and financial results. We take what we believe to be reasonable steps to protect these proprietary technologies and intellectual property, including contractually and by efforts to obtain patents or trade rights where possible. but there can be no assurance that all such measures will be sufficient or successful.

Changes in climate conditions and regulatory regime could adversely affect our business and operations.

Changes in climate conditions may have both favorable and adverse effects on our business in a range of possible ways. Mining and uranium processing operations are energy intensive and result in a carbon footprint either directly or through the purchase of fossil-fuel based electricity. As such, we are impacted by current and emerging policy and regulation relating to greenhouse gas emission levels, energy efficiency, and reporting of climate-change related risks. While some of the costs associated with reducing emissions may be offset by increased energy efficiency, technological innovation, or the increased demand for our uranium and conversion services, such regulations may result in additional transition costs at some of our operations. A number of government or governmental bodies have introduced or are contemplating regulatory changes in response to the potential impacts of climate change. Where legislation already exists, regulations relating to emissions levels and energy efficiency are becoming more stringent. Changes in legislation and regulation will likely increase our compliance costs.

In addition, the physical risks of climate change may also have an adverse effect at our operations. These may include extreme weather events such as floods, droughts, forest and bush fires, and extreme storms. These physical impacts could

require us to suspend or reduce production or close operations and could prevent us from pursuing expansion opportunities. These effects may adversely impact the cost, production, and financial performance of our operations.

We can provide no assurance that efforts to mitigate the risks of climate change will be effective and that physical risks of climate change will not have a material and adverse effect on our earnings, cash flows, financial condition, results of operations, or prospects.

Investors may experience future dilution as a result of additional equity offerings.

To raise additional capital, we may in the future offer additional common shares or other securities convertible into or exchangeable for our common shares at prices that may not be the same as the price per share as the shares an investor has previously purchased, and investors purchasing shares or other securities in the future could have rights superior to existing shareholders.

Item 1B. Unresolved Staff Comments

None

Item 1C. Cybersecurity

We rely on information technology to operate our business. We have endpoint and other protection systems, and incident response processes, both internally and through third-party experts designed to protect our information technology systems. These established processes assist us to continuously assess and identify threats to our systems and minimize impact to our business in the event of a breach or other security incident. Additionally, the Company has implemented numerous information technology policies and procedures concerning cybersecurity matters, which include policies that directly or indirectly relate to encryption standards, antivirus protection, remote access, multi-factor authentication, confidential information and the use of the internet, social media, email and wireless and personal devices for both Company business and personal matters while utilizing Company resources. These policies go through an internal review process on a periodic basis and are, if needed, updated and re-approved by the appropriate members of management. With our third-party consultants, the processes protect our information systems and allow us to resolve any issue which may arise in the most timely and aggressive fashion.

As any new threat to security may be identified, our personnel are notified, with instruction to increase awareness of the threat and how to react if such a threat or actual breach appears to be encountered. Periodic educational notices are also disseminated to all personnel. Additionally, as our systems are modified and upgraded, all personnel are notified, with instruction as appropriate. Responsibility for the identification and assessment of risks and the recommendation of upgrades to our systems resides with our expert consultants who report to our Interim Chief Executive Officer.

Governance

Our Board oversees the risks involved in our operations as part of its general oversight function, integrating risk management into the Company's compliance policies and procedures. With respect to cybersecurity, the Audit Committee of the Board has the ultimate oversight responsibility relating to risk management of cybersecurity.

Among other things, the Audit Committee discusses with management the Company's major policies with respect to risk assessment and risk management, including cyber security, as they relate to the integrity of the Company's accounting and financial reporting processes and the Company's compliance with legal and regulatory requirements.

In addition to its other responsibilities, the Board as a whole oversees operational information technology risks, including cybersecurity, as they relate to the technical aspects of the Company's operations. The full Board receives at least annual reports from management on information technology matters, including cybersecurity. The reports address upgrades to hardware, software, and IT systems throughout the Company, and include the identification of IT and cybersecurity risks. Security scores, risk management, and mitigation measures are routinely presented. As discussed above, we maintain endpoint and other protection systems, and incident response processes, both internally and through third-party experts. As these systems, processes, training, and upgrades are implemented, updates are provided to the Board.

Risks
Risks
[YTJ1]
[KM2]
from cybersecurity threats, including as a result of any previous cybersecurity incidents, have not materially affected, and we do not believe are reasonably likely to materially affect us, including our business strategy, results of operations or financial statements. However, the risk of cybersecurity threats could be significant if the cyber-attack disrupts the Company's critical operations, service or financial systems.

Risks from cybersecurity threats, including as a result of any previous cybersecurity incidents, have not materially affected, and we do not believe are reasonably likely to materially affect us, including our business strategy, results of operations or financial statements. However, the risk of cybersecurity threats could be significant if the cyber-attack disrupts the Company's critical operations, service or financial systems. For additional information regarding risks from cybersecurity threats, please refer to Item 1A, "Risk Factors," *We are dependent on information technology systems, which are subject to certain risks, including cybersecurity risks and data leakage risks associated with implementation and integration"* above.

Item 2. Properties

Please refer to Item 1. "Business and Properties" of this Annual Report for information concerning our properties.

Item 3. Legal Proceedings

From time to time, we are party to legal proceedings that arise in the ordinary course of our business. Management is not aware of any legal proceedings of which the outcome is reasonably likely to have a material adverse effect on our results of operations or financial condition, nor are we aware of any such legal proceedings contemplated by government agencies.

Item 4. Mine Safety Disclosures

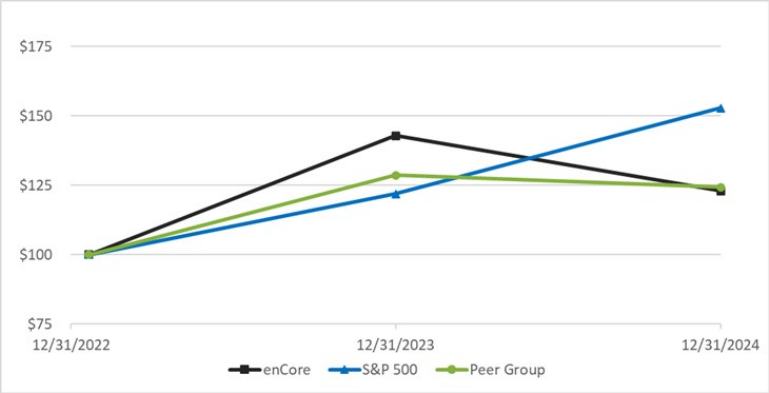
Our operations and other activities are not subject to regulation by the Federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the "Mine Act").

Part II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Performance Graph

The performance graph below compares the cumulative total return of our common stock to (a) the cumulative total return of the Standard & Poor's 500 Stock Index ("S&P 500") and (b) a composite peer group ("Peer Group") consisting of Boss Energy, Centrus Energy Group, Denison Mines Corp and Energy Fuels. The graph assumes that the value of the investment in common stock and each index was $100 on January 20, 2023, which is the date the Company's common shares were registered under the US Exchange Act. The performance graph assumes that all dividends were reinvested. The Peer Group is weighted on the basis of market capitalization.



Market Information

The authorized capital of the Company consists of an unlimited number of Common Shares without par value and an unlimited number of Preferred Shares without par value (referred to herein as the "**enCore Preferred Shares**"). As at December 31, 2024, there were 186,114,948 Common Shares issued and outstanding and held by 198 record holders. As at the date of this Annual Report on Form 10-K, there are 186,261,281 Common Shares issued and outstanding. Nil enCore Preferred Shares are issued and outstanding as at the date of this Annual Report on Form 10-K.The number of record holders is based on the records of Computershare Investor Services Inc., who serves as our transfer agent. The number of holders does not include individuals or entities who beneficially own shares but whose shares are held of record by a broker or clearing agency, but does include each such broker or clearing agency as one record holder.

The Common Shares are subject to the following rights, privileges, restrictions and conditions:

- the holders of the Common Shares are entitled to receive notice of, and attend at, and to vote in person or by proxy at general meetings of enCore shareholders and will be entitled to one vote for each such enCore Share held;

- subject to the rights of the enCore Preferred Shares as determined by the directors and in accordance with enCore's Articles, the directors may, in their discretion, at any time and from time to time declare and cause enCore to pay dividend on the Common Shares; and

- subject to the rights, privileges, restrictions and conditions attaching to the enCore Preferred Shares, in the event of liquidation or dissolution of enCore or other distribution of assets of enCore among its shareholders for the purpose of winding up its affairs, whether voluntary or involuntary, the holders of the Common Shares will be entitled to share equally, share for share, in the distribution of the remaining property and assets of enCore.

The rights and restrictions attached to the Common Shares may be altered by resolutions of the enCore Board, subject to the *Business Corporations Act* (British Columbia).

As at the date of this Annual Report, enCore has 8,818,393 stock options issued and outstanding.

As at December 31, 2024, the Company had 19,934,084 share purchase warrants to purchase Common Shares of the Company's outstanding as follows:

Number Issued	Weighted Average Exercise Price (C$)	Expiry Date
2,444	3.27	May 2025
19,931,640	3.81	February 2026

As at the date of this Annual Report, enCore has 19,844,084 warrants issued and outstanding.

Dividend Policy

We have never declared cash dividends on our Common Shares. We anticipate that we will retain any earnings to support operations and to finance the growth of our business. Therefore, we do not expect to pay cash dividends in the foreseeable future. Any further determination to pay cash dividends will be at the discretion of our Board of Directors and will be dependent on the financial condition, operating results, capital requirements, and other factors that our Board of Directors deems relevant.

Unregistered Sales of Equity Securities

The following represents securities sold by the Company in the three years ended December 31, 2024 which were not registered under the Securities Act. Included are new issuances, securities issued in exchange for property, services or other securities, securities issued upon conversion or vesting of other Company securities. The Company issued all of the securities listed below pursuant to the exemption from registration provided by Rule 701 of the Securities Act, Section 4(a)(2) of the Securities Act, or Regulation D or Regulation S promulgated thereunder.

On March 25, 2022, the Company completed a "bought deal" prospectus offering pursuant to which the Company sold an aggregate of 19,607,842 units of the Company at a price of C$1.53 per unit for aggregate gross proceeds of C$29,999,998.26. Each unit was comprised of one common share and one-half of one common share purchase warrant of the Company. Each whole warrant entitles the holder thereof to purchase one common share at an exercise price of C$2.00 until March 25, 2024. The underwriters included Clarus Securities Inc., PI Financial Corp. and Red Cloud Securities Inc. The Company paid the underwriters a cash commission of C$1,612,499.93 and issued an aggregate of 1,053,922 compensation options of the Company. Each compensation option is exercisable to acquire one common share at an exercise price of C$1.53 per share until March 25, 2024. The Company planned to use the net proceeds to maintain and advance the Company's material properties, acquire properties, plant upgrades, maintenance and refurbishment, and for general corporate and working capital purposes. The units were issued to investors outside of the United States in reliance upon exemption from registration afforded by Regulation S promulgated under the Securities Act.]

In September 2022, the Company consolidated the common shares on the basis of one (1) post-consolidation common share for every three (3) pre-consolidation common shares. The exercise price and the number of common shares issuable under any of the outstanding warrants, stock options or other convertible securities issued prior to the consolidation was proportionately adjusted. The common shares were issued to investors outside of the United States in reliance upon exemption from registration afforded by Regulation S promulgated under the Securities Act.

On February 15, 2023, the Company closed the acquisition of the Alta Mesa Project for $60 million in cash and a $60 million secured convertible promissory note (the "Note"). The Note has a two (2) year term and bears interest at a rate of 8% per annum payable on June 30th and December 31st of each year during the term. The Note is convertible at the election of the holder, to acquire common shares of enCore at a price of C$2.9103 per share. The holder agreed not to transact with the common shares of enCore received on conversion of the Note, including hedging and short sales, with exceptions for sale transactions of up to C$10 million in value in any 30-day period, block trades and underwritten distributions. In addition, the holder agreed to standard standstill provisions restricting additional acquisitions of enCore securities. On February 7, 2024, the full outstanding principal amount of the Note in the amount of $20 million was converted into 6,872,143 common shares of the Company. The common shares were issued in reliance upon the exemptions from

registration afforded by Section 4(a)(2) and Rule 506(b) promulgated under the Securities Act, because (i) the issuances were not made by general solicitation or advertising and (ii) the issuances were made only to "accredited investors" (as such term is defined in Rule 501(a) of Regulation D under the Securities Act).

On February 26, 2024, the Company issued 2,564,102 common shares of enCore at a price of $3.90 per share to Boss in connection with the joint venture in the Alta Mesa Project. The common shares were sold pursuant to the exemption from the registration requirements of the Securities Act provided by Rule 903 of Regulation S under the Securities Act. The common shares were issued in reliance upon the exemptions from registration afforded by Section 4(a)(2) and Rule 506(b) promulgated under the Securities Act, because (i) the issuances were not made by general solicitation or advertising and (ii) the issuances were made only to "accredited investors" (as such term is defined in Rule 501(a) of Regulation D under the Securities Act).

During the fiscal year ended December 31, 2024, the Company issued 8,781,985 common shares pursuant to the exercise of warrants for gross proceeds of $25,471. During the fiscal year ended December 31, 2023, the Company issued 6,034,478 common shares to warrant holders pursuant to the exercise of warrants for gross proceeds of $14,969,000. The common shares were sold pursuant to the exemption from the registration requirements of the Securities Act provided by Rule 903 of Regulation S promulgated under the Securities Act and Rule 4(a)(2) of the Securities Act because (i) the issuances were to investors outside the United States and/or (ii) in a transaction not involving any public offering.

From January 1, 2022 to July 7, 2023, the Company issued 1,354,716 common shares to employees pursuant to the exercise of options granted under the Company's Stock Option Plan, as amended and restated November 30, 2021 (the "Stock Option Plan") in reliance upon the exemption from registration afforded by Rule 701 of the Securities Act.]

During the year ended December 31, 2023, the Company issued 10,615,650 units consisting of one common share and one-half share purchase warrant for gross proceeds of $20.2 million. Each whole warrant entitles the holder to purchase one additional share at a fixed price for a period of three years. The units were issued to investors outside of the United States in reliance upon exemption from registration afforded by Regulation S promulgated under the Securities Act.]

On December 6, 2022, the Company completed a "bought deal" brokered private placement of an aggregate of 23,000,000 subscription receipts of the Company at a price of C$3.00 per subscription receipt (the "Issue Price") for aggregate gross proceeds to enCore of C$69 million (the "Subscription Receipt Offering"), including the full exercise of the Underwriters' option. Concurrently, enCore completed a non-brokered private placement of 277,000 subscription receipts at the Issue Price for aggregate gross proceeds to enCore of C$831,000 (the "Concurrent Offering", and collectively with the Offering, the "Private Placements"). The Subscription Receipt Offering was completed pursuant to an underwriting agreement entered into among enCore, Canaccord Genuity Corp., Haywood Securities Inc., Cantor Fitzgerald Canada Corporation, PI Financial Corp., Clarus Securities Inc., and Red Cloud Securities Inc. In consideration for their services, the underwriters were paid a cash commission equal to 6% of the gross proceeds of the Subscription Receipt Offering subject to 50% of the cash commission payable in respect of the subscription receipts held in escrow pending the satisfaction of escrow release conditions. Additionally, in consideration for their services, the underwriters were issued an aggregate of 1,350,000 non-transferable broker warrants (the "Broker Warrants") of enCore, with each Broker Warrant being exercisable into one common share (each, a "Broker Warrant Share") of enCore at a price of C$3.25 per Broker Warrant Share from the completion of the Subscription Receipt Offering until 27 months following the satisfaction of the escrow release conditions the Subscription Receipt Offering was subject to. In connection with the Concurrent Offering, enCore paid an aggregate of $13,800 as finder's fee commissions. During the year ended December 31, 2023, 23,277,000 subscription receipts issued in the Subscription Receipt Offering were converted into units for gross proceeds of $51.2 million. Each unit is comprised of one common share of enCore and one share purchase warrant. Each warrant entitles the holder to purchase one additional share for a period of three years for a fixed price. The subscription receipts and common shares were issued to investors outside of the United States in reliance upon exemption from registration afforded by Regulation S promulgated under the Securities Act

Issuer Repurchases of Equity Securities

The Company did not purchase its own equity securities during the fiscal quarter ended December 31, 2024.

CERTAIN CANADIAN FEDERAL INCOME TAX CONSIDERATIONS FOR NON-RESIDENTS OF CANADA

The following portion of this summary is generally applicable to a holder who acquires, as beneficial owner, our common shares, and who, for purposes of the Income Tax Act (Canada) and the regulations promulgated thereunder (the "Tax Act")

and at all relevant times, is neither resident nor deemed to be resident in Canada and does not use or hold, and will not be deemed to use or hold, common shares in a business carried on in Canada (each, a "Non-Resident Holder"). The term "American Holder," for the purposes of this summary, means a Non-Resident Holder who, for purposes of the Canada-U.S. Tax Convention, is at all relevant times a resident of the United States and is a "qualifying person" within the meaning of the Canada-U.S. Tax Convention eligible for the full benefits of the Canada-U.S. Tax Convention. In some circumstances, persons deriving amounts through fiscally transparent entities (including limited liability companies) may be entitled to benefits under the Canada-U.S. Tax Convention. American Holders are urged to consult their own tax advisors to determine their entitlement to benefits under the Canada-U.S. Tax Convention and related compliance requirements based on their particular circumstances.

Special considerations, which are not discussed in this summary, may apply to a Non-Resident Holder that is an insurer that carries on an insurance business in Canada and elsewhere or an authorized foreign bank (as defined in the Tax Act). Such Non-Resident Holders should consult their own advisors.

This summary is based upon the provisions of the Tax Act in force as of the date hereof, all specific proposals to amend the Tax Act that have been publicly and officially announced by or on behalf of the Minister of Finance (Canada) prior to the date hereof (the "Proposed Amendments") and management's understanding of the current administrative policies and assessing practices of the Canada Revenue Agency (the "CRA") published in writing by it prior to the date hereof. This summary assumes the Proposed Amendments will be enacted in the form proposed. However, no assurance can be given that the Proposed Amendments will be enacted in their current form, or at all. This summary is not exhaustive of all possible Canadian federal income tax considerations and, except for the Proposed Amendments, does not take into account or anticipate any changes in the law or any changes in the CRA's administrative policies or practices, whether by legislative, governmental, or judicial action or decision, nor does it take into account or anticipate any other federal or any provincial, territorial or foreign tax considerations, which may differ significantly from those discussed herein.

Non-Resident Holders should consult their own tax advisors with respect to an investment in our common shares. **This summary is of a general nature only and is not intended to be, nor should it be construed to be, legal or tax advice to any prospective purchaser or holder of our common shares, and no representations with respect to the income tax consequences to any prospective purchaser or holder are made. Consequently, prospective purchasers or holders of our common shares should consult their own tax advisors with respect to their particular circumstances.**

Currency Conversion

Generally, for purposes of the Tax Act, all amounts relating to the acquisition, holding, or disposition of our common shares, including dividends, adjusted cost base and proceeds of disposition, must be converted into Canadian Dollars based on the exchange rates as determined in accordance with the Tax Act. The amounts subject to withholding tax and any capital gains or capital losses realized by a Non-Resident Holder may be affected by fluctuations in the value of the Canadian Dollar relative to other currencies.

Taxation of Dividends

Subject to an applicable tax treaty or convention, dividends paid or credited, or deemed to be paid or credited, to a Non-Resident Holder on the common shares will be subject to Canadian withholding tax under the Tax Act at the rate of 25% of the gross amount of the dividend. Such rate is generally reduced under the Canada-U.S. Tax Convention to 15% if the beneficial owner of such dividend is an American Holder. The rate of withholding tax is generally further reduced to 5% if the beneficial owner of such dividend is an American Holder that is a company that owns, directly or indirectly, at least 10% of the voting shares of the Company. Non-Resident Holders should consult their own tax advisors to determine their entitlement to benefits under any applicable tax treaty or convention based on their particular circumstances.

Disposition of Common Shares

A Non-Resident Holder will not be subject to tax under the Tax Act in respect of any capital gain realized by such Non-Resident Holder on a disposition of common shares, unless the common shares constitute "taxable Canadian property" (as defined in the Tax Act) of the Non-Resident Holder at the time of the disposition and are not "treaty-protected property" (as defined in the Tax Act) of the Non-Resident Holder at the time of the disposition.

Generally, provided the common shares are listed on a "designated stock exchange" as defined in the Tax Act (which currently includes the TSXV and Nasdaq) at the time of disposition, the common shares will not constitute taxable

Canadian property of a Non-Resident Holder, unless at any time during the 60-month period immediately preceding the disposition the following two conditions are met concurrently: (a) the Non-Resident Holder, persons with which the Non-Resident Holder does not deal at arm's length, partnerships whose members include, either directly or indirectly through one or more partnerships, the Non-Resident Holder and/or persons which do not deal at arm's length with the Non-Resident Holder, or any combination of the foregoing, owned 25% or more of the issued shares of any class or series of shares of the capital stock of the Company, and (b) more than 50% of the fair market value of the common shares was derived directly or indirectly, from one or any combination of real or immovable property situated in Canada, "Canadian resource properties", "timber resource properties" (each as defined in the Tax Act), and options in respect of or interests in, or for civil law rights in, any such property (whether or not such property exists). Notwithstanding the foregoing, common shares may also be deemed to be "taxable Canadian property" of a Non-Resident Holder in other circumstances under the Tax Act.

The common shares of an American Holder will generally constitute "treaty-protected property" for purposes of the Tax Act unless the value of the common shares is derived principally from real property situated in Canada. For this purpose, "real property" has the meaning that term has under the laws of Canada and includes any option or similar right in respect thereof and in any case, includes usufruct of real property, rights to explore for or to exploit mineral deposits, sources and other natural resources and rights to amounts computed by reference to the amount or value of production from such resources.

If common shares are taxable Canadian property of a Non-Resident Holder and are not treaty-protected property of the Non-Resident Holder at the time of their disposition, the Non-Resident Holder may owe Canadian income tax on any taxable capital gains realized and should consult their own tax advisor with respect to the procedures that must be followed when disposing of taxable Canadian property.

Non-Resident Holders whose common shares may constitute taxable Canadian property should consult their own advisors.

CERTAIN U.S. FEDERAL INCOME TAX CONSIDERATIONS

The following is a general summary of certain U.S. federal income tax considerations applicable to a U.S. Holder (as defined below) arising from the ownership and disposition of common shares. This summary is for general information purposes only and does not purport to be a complete analysis or listing of all potential U.S. federal income tax considerations that may apply to a U.S. Holder. In addition, this summary does not take into account the individual facts and circumstances of any particular U.S. Holder that may affect the U.S. federal income tax consequences to such holder (as discussed below), including specific tax consequences to a holder under an applicable tax treaty. Accordingly, this summary is not intended to be, and should not be construed as, legal or U.S. federal income tax advice with respect to any holder. This summary is limited to U.S. federal income tax considerations, and does not address the U.S. federal alternative minimum, net investment income, U.S. federal estate and gift, U.S. state and local, or non-U.S. tax consequences of the ownership and disposition of such common shares. Except as specifically set forth below, this summary does not discuss applicable income tax reporting requirements. Each holder should consult its own tax advisor regarding all U.S. federal, U.S. state and local, and non-U.S. tax consequences of the ownership and disposition of common shares.

No opinion from U.S. legal counsel or ruling from the U.S. Internal Revenue Service ("IRS") has been requested, or will be obtained, regarding the U.S. federal income tax consequences of the ownership and disposition of common shares. This summary is not binding on the IRS, and the IRS is not precluded from taking a position that is different from, and contrary to, the positions taken in this summary. In addition, because the authorities on which this summary is based are subject to various interpretations, the IRS and the U.S. courts could disagree with one or more of the positions taken in this summary.

This summary does not address the U.S. federal income tax consequences to any particular person of the ownership and disposition of common shares. Each holder should consult its own tax advisor regarding all U.S. federal, U.S. state and local, and non-U.S. tax consequences of the ownership and disposition of common shares.

Scope of This Disclosure

Authorities

This summary is based on the U.S. Internal Revenue Code of 1986, as amended (the "Code"), proposed, final and temporary U.S. Treasury Regulations, published rulings of the IRS, published administrative positions of the IRS, and U.S.

court decisions that are applicable and, in each case, as in effect and available, as of the date of this Annual Report. Any of the authorities on which this summary is based could be changed in a material and adverse manner at any time, and any such change could be applied on a prospective or retroactive basis which could affect the U.S. federal income tax considerations described in this summary. This summary does not discuss the potential effects, whether adverse or beneficial, of any proposed legislation that, if enacted, could be applied on a retroactive or prospective basis.

U.S. Holders

For purposes of this summary, the term "U.S. Holder" means a beneficial owner of common shares that is for U.S. federal income tax purposes:

- an individual who is a citizen or resident of the United States;
- a corporation (or other entity taxable as a corporation for U.S. federal income tax purposes) created or organized in or under the laws of the United States, any state thereof or the District of Columbia;
- an estate the income of which is subject to U.S. federal income tax regardless of its source; or
- a trust that (a) is subject to the primary supervision of a court within the United States and the control of one or more U.S. persons for all substantial decisions or (b) has a valid election in effect under applicable U.S. Treasury Regulations to be treated as a U.S. person.

Non-U.S. Holders

Also, for purposes of this discussion, a "Non-U.S. Holder" is any beneficial owner of common stock who is neither a U.S. Holder nor an entity classified as a partnership for U.S. federal income tax purposes. This summary does not address the U.S. federal income tax considerations applicable to Non-U.S. Holders relating to the acquisition, ownership and disposition of common shares. Accordingly, Non-U.S. Holders should consult their own tax advisors regarding the U.S. federal, U.S. state and local, and non-U.S. tax consequences (including the potential application of and operation of any tax treaties) relating to the acquisition, ownership, and disposition of common shares.

U.S. Holders Subject to Special U.S. Federal Income Tax Rules Not Addressed

This summary does not address the U.S. federal income tax consequences of the ownership and disposition of common shares that are subject to special provisions under the Code, including holders that: (a) are tax-exempt organizations, qualified retirement plans, individual retirement accounts, or other tax-deferred accounts; (b) are financial institutions, underwriters, insurance companies, real estate investment trusts, or regulated investment companies; (c) are broker-dealers, dealers, or traders in securities or currencies that elect to apply a mark-to-market accounting method; (d) have a "functional currency" other than the U.S. dollar; (e) own, common shares as part of a straddle, hedging transaction, conversion transaction, constructive sale, or other arrangement involving more than one position; (f) acquired common shares in connection with the exercise of employee stock options or otherwise as compensation for services; (g) hold common shares other than as a capital asset within the meaning of Section 1221 of the Code (generally, property held for investment purposes); (h) own, directly, indirectly, or by attribution, 5% or more, by voting power or value, of the outstanding common shares; (i) are required to accelerate the recognition of any item of gross income for U.S. federal income tax purposes with respect to common shares as a result of such item being taken into account in an applicable financial statement; (j) acquired common shares by gift or inheritance; (k) are certain former citizens or long-term residents of the United States; (l) are pension plans; (m) are integral parts or controlled entities of foreign sovereigns; or (n) are passive foreign investment companies and corporations that accumulate earnings to avoid U.S. federal income tax. Holders that are subject to special provisions under the Code, including those holders described immediately above, should consult their own tax advisors regarding all U.S. federal, U.S. state and local, and non-U.S. tax consequences relating to the ownership and disposition of common shares.

If an entity or arrangement that is classified as a partnership (including any other "pass-through" entity) for U.S. federal income tax purposes holds common shares, the U.S. federal income tax consequences to such partnership and the partners (or owners) of such partnership of participating in the ownership and disposition of common shares generally will depend on the activities of the partnership and the status of such partners (or owners). This summary does not address the tax consequences to any such partnership or partner (or owner). Partners (or owners) of entities and arrangements that are classified as partnerships for U.S. federal, U.S. state and local, and non-tax purposes should consult their own tax advisors regarding the U.S. federal income tax consequences of the ownership and disposition of common shares.

U.S. Tax Considerations Relevant to the Ownership and Disposition of Common Shares

Distributions

We do not currently anticipate paying distributions on our common shares. Subject to the PFIC rules discussed below, a U.S. Holder that receives a distribution, including a constructive distribution, with respect to common shares will be required to include the amount of such distribution in gross income as a dividend (without reduction for any Canadian income tax withheld from such distribution) to the extent of the current or accumulated "earnings and profits" of the Company, as computed for U.S. federal income tax purposes. To the extent that a distribution exceeds the current and accumulated "earnings and profits" of the Company, such distribution will be treated first as a tax-free return of capital to the extent of a U.S. Holder's tax basis in the common shares and thereafter as a gain from the sale or exchange of such common shares(see "Sale, Exchange or Other Taxable Disposition of Common Shares" below). However, the Company does not intend to maintain the calculations of earnings and profits in accordance with U.S. federal income tax principles, and each U.S. Holder should therefore assume that any distribution by the Company with respect to the common shares will constitute ordinary dividend income. Subject to applicable limitations, dividends paid by the Company to non-corporate U.S. Holders, including individuals, generally will be eligible for the preferential tax rates applicable to long-term capital gains for dividends, provided certain holding period and other conditions are satisfied, including that the Company not be classified as a PFIC (as discussed below) in the tax year of distribution or in the preceding tax year. Dividends received on common shares by corporate U.S. Holders will not be eligible for the "dividends received deduction". The dividend rules are complex, and each U.S. Holder should consult its own tax advisor regarding the application of such rules.

Sale, Exchange or Other Taxable Disposition of Common Shares

Subject to the PFIC rules discussed below, upon the sale or other taxable disposition of common shares, a U.S. Holder generally will recognize capital gain or loss in an amount equal to the difference between (a) the amount of cash plus the fair market value of any property received and (b) its tax basis in such common shares sold or otherwise disposed of. Such gain generally will be treated as "U.S. source" for purposes of applying the U.S. foreign tax credit rules unless the gain is subject to tax in Canada and is re-sourced as "foreign source" under the Canada - US Tax Treaty and such U.S. Holder elects to treat such gain or loss as "foreign source" (see a more detailed discussion at "Foreign Tax Credit" below). Any such gain or loss generally will be capital gain or loss, which will be long-term capital gain or loss if, at the time of the sale or other disposition, such common shares is held for more than one year. Preferential tax rates apply to long-term capital gains of a U.S. Holder that is an individual, estate, or trust. There are currently no preferential tax rates for long-term capital gains of a U.S. Holder that is a corporation. Deductions for capital losses are subject to significant limitations under the Code.

Passive Foreign Investment Company Rules (PFIC)

If the Company is considered a PFIC within the meaning of Section 1297 of the Code at any time during a U.S. Holder's holding period, then certain different and potentially adverse tax consequences would apply to such U.S. Holder's acquisition, ownership and disposition of common shares.

PFIC Status of the Company

The Company generally will be a PFIC if, for a given tax year, (a) 75% or more of the gross income of the Company for such tax year is passive income or (b) 50% or more of the assets held by the Company either produce passive income or are held for the production of passive income, based on the fair market value of such assets. "Gross income" generally includes all revenues less the cost of goods sold plus income from investments and from incidental or outside operations or sources, and "passive income" includes, for example, dividends, interest, certain rents and royalties, certain gains from the sale of shares and securities, and certain gains from commodities transactions. Active business gains arising from the sale of commodities generally are excluded from passive income if substantially all of a foreign corporation's commodities are shares in trade or inventory, depreciable property used in a trade or business, or supplies regularly used or consumed in a trade or business, and certain other requirements are satisfied.

For purposes of the PFIC income test and asset test described above, if the Company owns, directly or indirectly, 25% or more of the total value of the outstanding shares of another corporation, the Company will be treated as if it (a) held a proportionate share of the assets of such other corporation and (b) received directly a proportionate share of the income of such other corporation. In addition, for purposes of the PFIC income test and asset test described above, "passive income"

does not include any interest, dividends, rents or royalties that are received or accrued by the Company from a "related person" (as defined in Section 954(d)(3) of the Code), to the extent such items are properly allocable to the income of such related person that is not passive income.

Under certain attribution rules, if the Company is a PFIC, U.S. Holders will be deemed to own their proportionate share of any subsidiary of the Company which is also a PFIC (a "Subsidiary PFIC"), and will be subject to U.S. federal income tax on (a) a distribution on the shares of a Subsidiary PFIC and (b) a disposition of shares of a Subsidiary PFIC, both as if the U.S. Holder directly held the shares of such Subsidiary PFIC.

Based on an analysis of the Company's activities and income and assets, the Company believes that it was a PFIC for its taxable year ended December 31, 2022, and 2023, and may continue to be classified as a PFIC for the taxable year ended December 31, 2024, the current taxable year and the foreseeable future. No opinion of legal counsel or ruling from the IRS concerning the status of the Company as a PFIC has been obtained or is currently planned to be requested. The determination of whether the Company (or a subsidiary of the Company) was, or will be, a PFIC for a tax year depends, in part, on the application of complex U.S. federal income tax rules, which are subject to differing interpretations. In addition, whether the Company (or subsidiary) will be a PFIC for any tax year depends on the assets and income of the Company (and each such subsidiary) over the course of each such tax year and, as a result, cannot be predicted with certainty as of the date of this document. Accordingly, there can be no assurance that the IRS will not challenge any determination made by the Company (or subsidiary) concerning its PFIC status or that the Company (and any subsidiary) was not, or will not be, a PFIC for any tax year. U.S. Holders should consult their own tax advisors regarding the PFIC status of the Company and any subsidiary of the Company.

Default PFIC Rules under Section 1291 of the Code

If the Company is a PFIC, the U.S. federal income tax consequences to a U.S. Holder of the acquisition, ownership and disposition of common shares will depend on whether such U.S. Holder makes a qualified electing fund election (a "QEF Election") or makes a mark-to-market election under Section 1296 of the Code (a "Mark-to-Market Election") with respect to its common shares. A U.S. Holder that does not make either a QEF Election or a Mark-to-Market Election will be referred to in this summary as a "Non-Electing U.S. Holder".

A Non-Electing U.S. Holder will be subject to the rules of Section 1291 of the Code with respect to (a) any gain recognized on the sale or other taxable disposition of the common shares and (b) any excess distribution paid on the common shares. A distribution generally will be an "excess distribution" to the extent that such distribution (together with all other distributions received in the current tax year) exceeds 125% of the average distributions received during the three preceding tax years (or during a U.S. Holder's holding period for the common shares, if shorter).

If the Company is a PFIC, under Section 1291 of the Code any gain recognized on the sale or other taxable disposition of common shares (including an indirect disposition of shares of a Subsidiary PFIC), and any excess distribution paid on the common shares (or a distribution by a Subsidiary PFIC to its shareholder that is deemed to be received by a U.S. Holder) must be ratably allocated to each day of a Non-Electing U.S. Holder's holding period for the common shares. The amount of any such gain or excess distribution allocated to the tax year of disposition or excess distribution and to years before the Company became a PFIC, if any, would be taxed as ordinary income. The amounts allocated to any other tax year would be subject to U.S. federal income tax at the highest tax applicable to ordinary income in each such year, and an interest charge would be imposed on the tax liability for each such year, calculated as if such tax liability had been due in each such year. A Non-Electing U.S. Holder that is not a corporation must treat any such interest paid as "personal interest", which is not deductible.

If the Company is a PFIC for any tax year during which a Non-Electing U.S. Holder holds common shares, the Company will continue to be treated as a PFIC with respect to such Non-Electing U.S. Holder, regardless of whether the Company ceases to be a PFIC in one or more subsequent years. If the Company ceases to be a PFIC, a Non-Electing U.S. Holder may terminate this deemed PFIC status with respect to the common shares by electing to recognize gain (which will be taxed under the rules of Section 1291 of the Code discussed above) as if such common shares were sold on the last day of the last tax year for which the Company was a PFIC.

QEF Election

In the event the Company is a PFIC and a U.S. Holder makes a QEF Election for the first tax year in which its holding period of its common shares begins, such U.S. Holder generally will not be subject to the rules of Section 1291 of the Code

discussed above with respect to its common shares. However, a U.S. Holder that makes a QEF Election will be subject to U.S. federal income tax on such U.S. Holder's pro rata share of (a) the net capital gain of the Company, which will be taxed as long-term capital gain to such U.S. Holder, and (b) the ordinary earnings of the Company, which will be taxed as ordinary income to such U.S. Holder. Generally, "net capital gain" is the excess of (a) net long-term capital gain over (b) net short-term capital gain, and "ordinary earnings" are the excess of (a) "earnings and profits" over (b) net capital gain. A U.S. Holder that makes a QEF Election will be subject to U.S. federal income tax on such amounts for each tax year in which the Company is a PFIC, regardless of whether such amounts are actually distributed to such U.S. Holder by the Company. However, a U.S. Holder that makes a QEF Election may, subject to certain limitations, elect to defer payment of current U.S. federal income tax on such amounts, subject to an interest charge. If such U.S. Holder is not a corporation, any such interest paid will be treated as "personal interest", which is not deductible.

A U.S. Holder that makes a QEF Election generally (a) may receive a tax-free distribution from the Company to the extent that such distribution represents "earnings and profits" of the Company that were previously included in income by the U.S. Holder because of such QEF Election and (b) will adjust such U.S. Holder's tax basis in the common shares to reflect the amount included in income or allowed as a tax-free distribution because of such QEF Election. In addition, a U.S. Holder that makes a QEF Election generally will recognize capital gain or loss on the sale or other taxable disposition of common shares.

The procedure for making a QEF Election, and the U.S. federal income tax consequences of making a QEF Election, will depend on whether such QEF Election is timely. A QEF Election will be treated as "timely" if it is made for the first year in the U.S. Holder's holding period for the common shares in which the Company was a PFIC. A U.S. Holder may make a timely QEF Election by filing the appropriate QEF Election documents at the time such U.S. Holder files a U.S. federal income tax return for such year.

A QEF Election will apply to the tax year for which such QEF Election is made and to all subsequent tax years, unless such QEF Election is invalidated or terminated or the IRS consents to revocation of such QEF Election. If a U.S. Holder makes a QEF Election and, in a subsequent tax year, the Company ceases to be a PFIC, the QEF Election will remain in effect (although it will not be applicable) during those tax years in which the Company is not a PFIC. Accordingly, if the Company becomes a PFIC in a subsequent tax year, the QEF Election will be effective, and the U.S. Holder will be subject to the QEF rules described above during a subsequent tax year in which the Company qualifies as a PFIC.

The Company intends to make available to U.S. Holders, upon their written request, all information and documentation that a U.S. Holder making a QEF Election with respect to the Company is required to obtain for U.S. federal income tax purposes. Such information may be included on the Company's website. However, U.S. Holders should be aware that the Company can provide no assurances that it will provide any such information relating to any Subsidiary PFIC. Because the Company may own shares in one or more Subsidiary PFICs and may acquire shares in one or more Subsidiary PFICs in the future, U.S. Holders will continue to be subject to the rules discussed above with respect to the taxation of gains and excess distributions with respect to any Subsidiary PFIC for which the U.S. Holders do not obtain the required information to file a QEF Election. U.S. Holders should consult their own tax advisor regarding the availability of, and procedure for making, a QEF Election with respect to the Company and any Subsidiary PFIC.

Mark-to-Market Election

A U.S. Holder may make a Mark-to-Market Election only if the common shares is marketable shares. The common shares generally will be "marketable stock" if it is regularly traded on (a) a national securities exchange that is registered with the SEC; (b) the national market system established pursuant to section 11A of the Securities and Exchange Act of 1934; or (c) a foreign securities exchange that is regulated or supervised by a governmental authority of the country in which the market is located, provided that (i) such foreign exchange has trading volume, listing, financial disclosure and other requirements and the laws of the country in which such foreign exchange is located, together with the rules of such foreign exchange, ensure that such requirements are actually enforced; and (ii) the rules of such foreign exchange ensure active trading of listed shares. If such shares is traded on such a qualified exchange or other market, such shares generally will be "regularly traded" for any calendar year during which such shares is traded, other than in de minimis quantities, on at least 15 days during each calendar quarter. Each U.S. Holder should consult its own tax advisor regarding whether the common shares constitutes marketable stock.

A U.S. Holder that makes a Mark-to-Market Election with respect to its common shares generally will not be subject to the rules of Section 1291 of the Code discussed above. However, if a U.S. Holder does not make a Mark-to-Market Election beginning in the first tax year of such U.S. Holder's holding period for common shares or such U.S. Holder has not made a

timely QEF Election, the rules of Section 1291 of the Code discussed above will apply to certain dispositions of, and distributions on, the common shares.

A U.S. Holder that makes a Mark-to-Market Election will include in ordinary income, for each tax year in which the Company is a PFIC, an amount equal to the excess, if any, of (a) the fair market value of the common shares, as of the close of such tax year over (b) such U.S. Holder's tax basis in such common shares. A U.S. Holder that makes a Mark-to-Market Election will be allowed a deduction in an amount equal to the excess, if any, of (i) such U.S. Holder's adjusted tax basis in the common shares over (ii) the fair market value of such common shares (but only to the extent of the net amount of previously included income as a result of the Mark-to-Market Election for prior tax years).

U.S. Holders that make a Mark-to-Market Election generally also will adjust their tax basis in the common shares to reflect the amount included in gross income or allowed as a deduction because of such Mark-to-Market Election. In addition, upon a sale or other taxable disposition of common shares, a U.S. Holder that makes a Mark-to-Market Election will recognize ordinary income or loss (not to exceed the excess, if any, of (a) the amount included in ordinary income because of such Mark-to-Market Election for prior tax years over (b) the amount allowed as a deduction because of such Mark-to-Market Election for prior tax years).

A Mark-to-Market Election applies to the tax year in which such Mark-to-Market Election is made and to each subsequent tax year, unless the common shares ceases to be "marketable stock" or the IRS consents to revocation of such election. U.S. Holders should consult their own tax advisors regarding the availability of, and procedure for making, a Mark-to-Market Election.

Although a U.S. Holder may be eligible to make a Mark-to-Market Election with respect to common shares, no such election may be made with respect to the shares of any Subsidiary PFIC that a U.S. Holder is treated as owning because such shares are not marketable. Hence, the Mark-to-Market Election will not be effective to eliminate the interest charge described above with respect to deemed dispositions of Subsidiary PFIC shares or distributions from a Subsidiary PFIC.

Other PFIC Rules

Under Section 1291(f) of the Code, the IRS has issued proposed Treasury Regulations that, subject to certain exceptions, would cause a U.S. Holder that had not made a timely QEF Election to recognize gain (but not loss) upon certain transfers of common shares that would otherwise be tax-deferred (e.g., gifts and exchanges pursuant to corporate reorganizations) in the event the Company is a PFIC during such U.S. Holder's holding period for the relevant shares. However, the specific U.S. federal income tax consequences to a U.S. Holder may vary based on the manner in which common shares is transferred.

Certain additional adverse rules will apply with respect to a U.S. Holder if the Company is a PFIC, regardless of whether such U.S. Holder makes a QEF Election. For example, under Section 1298(b)(6) of the Code, a U.S. Holder that uses common shares as security for a loan will, except as may be provided in Treasury Regulations, be treated as having made a taxable disposition of such common shares.

In any year in which the Company is classified as a PFIC, a U.S. Holder will be required to file an annual report with the IRS containing such information as Treasury Regulations and/or other IRS guidance may require. U.S. Holders should consult their own tax advisors regarding the requirements of filing such information returns under these rules, including the requirement to file an IRS Form 8621.

In addition, a U.S. Holder who acquires common shares from a decedent will not receive a "step up" in tax basis of such common shares to fair market value unless such decedent had a timely and effective QEF Election in place.

Special rules also apply to the amount of foreign tax credit that a U.S. Holder may claim on a distribution from a PFIC.

The PFIC rules are complex, and U.S. Holders should consult their own tax advisors regarding the PFIC rules and how they may affect the U.S. federal income tax consequences of the acquisition, ownership, and disposition of common shares in the event the Company is a PFIC at any time during such holding period for such common shares.

Additional Considerations

Receipt of Foreign Currency

The amount of any distribution paid in foreign currency to a U.S. Holder in connection with the ownership of common shares, or on the sale, exchange or other taxable disposition of common shares, generally will be equal to the U.S. dollar value of such foreign currency based on the exchange rate applicable on the date of receipt or, if applicable, the date of settlement if the common shares is traded on an established securities market (regardless of whether such foreign currency is converted into U.S. dollars at that time). If the foreign currency received is not converted into U.S. dollars on the date of receipt, a U.S. Holder will have a basis in the foreign currency equal to its U.S. dollar value on the date of receipt. A U.S. Holder that receives foreign currency and converts such foreign currency into U.S. dollars at a conversion rate other than the rate in effect on the date of receipt may have a foreign currency exchange gain or loss, which generally would be treated as U.S. source ordinary income or loss for foreign tax credit purposes. Different rules apply to U.S. Holders who use the accrual method of tax accounting. U.S. Holders should consult their own U.S. tax advisors regarding the U.S. federal income tax consequences of receiving, owning and disposing of foreign currency.

Foreign Tax Credit

Dividends paid on the common shares will be treated as foreign-source income, and generally will be treated as "passive category income" or "general category income" for U.S. foreign tax credit purposes. Any gain or loss recognized on a sale or other disposition of common shares generally will be United States source gain or loss. Certain U.S. Holders that are eligible for the benefits of the Canada - US Tax Treaty may elect to treat such gain or loss as Canadian source gain or loss for U.S. foreign tax credit purposes. The Code applies various complex limitations on the amount of foreign taxes that may be claimed as a credit by U.S. taxpayers. In addition, Treasury Regulations that apply to foreign taxes paid or accrued (the "Foreign Tax Credit Regulations") impose additional requirements for Canadian withholding taxes to be eligible for a foreign tax credit, and there can be no assurance that those requirements will be satisfied. The Treasury Department has recently released guidance temporarily pausing the application of certain of the Foreign Tax Credit Regulations.

Subject to the PFIC rules and the Foreign Tax Credit Regulations, each as discussed above, a U.S. Holder that pays (whether directly or through withholding) Canadian income tax with respect to dividends paid on the common shares generally will be entitled, at the election of such U.S. Holder, to receive either a deduction or a credit for such Canadian income tax. Generally, a credit will reduce a U.S. Holder's U.S. federal income tax liability on a dollar-for-dollar basis, whereas a deduction will reduce a U.S. Holder's income that is subject to U.S. federal income tax. This election is made on a year-by-year basis and applies to all foreign taxes paid (whether directly or through withholding) by a U.S. Holder during a year. The foreign tax credit rules are complex and involve the application of rules that depend on a U.S. Holder's particular circumstances. Accordingly, each U.S. Holder should consult its own U.S. tax advisor regarding the foreign tax credit rules.

Information Reporting, Backup Withholding Tax

Under U.S. federal income tax law and Treasury Regulations, certain categories of U.S. Holders must file information returns with respect to their investment in, or involvement in, a foreign corporation. For example, U.S. return disclosure obligations (and related penalties) are imposed on individuals who are U.S. Holders that hold certain specified foreign financial assets in excess of certain threshold amounts. The definition of specified foreign financial assets includes not only financial accounts maintained in foreign financial institutions, but also, unless held in accounts maintained by a financial institution, any shares or security issued by a non-U.S. person, any financial instrument or contract held for investment that has an issuer or counterparty other than a U.S. person and any interest in a non-U.S. entity. U.S. Holders may be subject to these reporting requirements unless their common shares are held in an account at certain financial institutions. Penalties for failure to file certain of these information returns are substantial. U.S. Holders should consult their own tax advisors regarding the requirements of filing information returns, including the requirement to file an IRS Form 8938.

Payments made within the U.S. or by a U.S. payor or U.S. middleman, of dividends on, and proceeds arising from the sale or other taxable disposition of common shares will generally be subject to information reporting and backup withholding tax if a U.S. Holder (a) fails to furnish such U.S. Holder's correct U.S. taxpayer identification number (generally on IRS Form W-9), (b) furnishes an incorrect U.S. taxpayer identification number, (c) is notified by the IRS that such U.S. Holder has previously failed to properly report items subject to backup withholding tax, or (d) fails to certify, under penalty of perjury, that such U.S. Holder has furnished its correct U.S. taxpayer identification number and that the IRS has not notified such U.S. Holder that it is subject to backup withholding tax. However, certain exempt persons generally are excluded from these information reporting and backup withholding rules. Backup withholding is not an additional tax. Any amounts withheld under the U.S. backup withholding tax rules will be allowed as a credit against a U.S. Holder's U.S.

federal income tax liability, if any, or will be refunded, if such U.S. Holder furnishes required information to the IRS in a timely manner.

The discussion of reporting requirements set forth above is not intended to constitute a complete description of all reporting requirements that may apply to a U.S. Holder. A failure to satisfy certain reporting requirements may result in an extension of the time period during which the IRS can assess a tax, and under certain circumstances, such an extension may apply to assessments of amounts unrelated to any unsatisfied reporting requirement. Each U.S. Holder should consult its own tax advisors regarding the information reporting and backup withholding rules.

THE ABOVE SUMMARY IS NOT INTENDED TO CONSTITUTE A COMPLETE ANALYSIS OF ALL TAX CONSIDERATIONS APPLICABLE TO U.S. HOLDERS WITH RESPECT TO THE ACQUISITION, OWNERSHIP AND DISPOSITION OF COMMON SHARES. U.S. HOLDERS SHOULD CONSULT THEIR OWN TAX ADVISORS AS TO THE TAX CONSIDERATIONS APPLICABLE TO THEM IN LIGHT OF THEIR OWN PARTICULAR CIRCUMSTANCES.

Item 6. [Reserved]

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is a discussion and analysis of the Company's financial condition and historical results of operations. The following should be read in conjunction with our financial statements and accompanying notes. This discussion contains forward-looking statements that involve risks, uncertainties and assumptions. Our actual results could differ materially from those projected, forecasted or expected in these forward-looking statements as a result of various factors, including but not limited to, those discussed below and elsewhere in this Annual Report. Refer to "Cautionary Note Regarding Forward-looking Statements" and Item 1A. Risk Factors herein. Our management believes the assumptions underlying the Company's financial statements and accompanying notes are reasonable. However, the Company's financial statements and accompanying notes may not be an indication of our financial condition and results of operations in the future.

Business Overview

The following discussion is designed to provide information that we believe necessary for an understanding of our financial condition, changes in financial condition and results of our operations. The following discussion and analysis should be read in conjunction with the accompanying audited consolidated financial statements and related notes. The financial statements have been prepared in accordance with US GAAP.

The primary use of uranium is to fuel nuclear power plants for the generation of carbon and emission free electricity. According to the World Nuclear Association ("WNA"), as of January 2025, there were 440 operable nuclear reactors world-wide, which required approximately 175.2 million pounds of U_3O_8 annually at full operation. Worldwide, there are currently 65 new reactors under construction with an additional 86 reactors on order or in the planning stage and 344 having been proposed. According to data from TradeTech LLC ("TradeTech"), the world continues to require more uranium than it produces from primary extraction. The gap between demand and primary supply is being filled by stockpiled inventories and secondary supplies, which the Company believes have dwindled significantly in recent years.

According to the WNA in January 2025, the U.S. currently has 94 operating reactors, and other reactors on order, planned or proposed. According to the U.S. Energy Information Administration ("EIA"), in 2023, the U.S. produced approximately 18.52% of its electricity from nuclear technology, while, according to the Nuclear Energy Institute ("NEI"), the U.S. achieved an average capacity factor of 92.7%, leading all other carbon-free sources by a wide margin. According to the EIA, U.S. utilities purchased approximately 51.63 million pounds of U_3O_8 in 2023 (the last year reported). However, in 2023, U.S. uranium production was only 0.05 million pounds, as reported by EIA.

Uranium is not traded on an open market or organized commodity exchange, although the CME Group provides financially settled uranium futures contracts. Typically, buyers and sellers negotiate transactions privately, either directly or through brokers and intermediaries. Spot uranium transactions typically involve deliveries that occur immediately and up to 12 months in the future. Term uranium transactions typically involve deliveries that occur more than 12 months in the future, with long-term transactions involving delivery terms of at least three years. Uranium prices, both spot and term, are primarily published by two independent market consulting firms, TradeTech and UxC, LLC, on a weekly and monthly basis, along with daily price indicators. Other brokers, including Uranium Markets LLC, Evolution Markets Inc. and Numerco Ltd., also publish daily average uranium prices.

During the period ending December 31, 2024, the uranium market saw uranium prices exceed $100 per pound U_2O_8 in the first quarter of the year.[1] By the end of the year, spot prices had moderated to $73.50 per pound U_3O_8.[2] The Company, as previously disclosed, continued to see continued nuclear utility and trading company interest in term contracting. Generally, spot and contracting volumes remain below levels observed in 2022 and 2023, and that is driven by continued geopolitical uncertainty, transportation challenges, trade restrictions, and uncertainty regarding new primary production supply. However, many of the same fundamentals that have led to the recent resurgence in support for nuclear power remain unchallenged. In 2025, the nuclear fuel market is poised to be influenced by three major macroeconomic forces: net-zero carbon emissions initiatives, emerging demand in the technology sector, and trade restrictions.

Net-zero policies require reliable, efficient, and cost-effective electricity generation that contributes to meaningful reductions in carbon emissions. These policies have led to a widespread recognition that nuclear power must play a role in meeting commitments to mitigate climate change through clean energy development. These developments build on a long-run trend in energy policy reform that has evolved to acknowledge and support nuclear power's critical role in achieving carbon reduction goals, and now the financial markets are following with material support for real demand that is emerging faster than current generating capacity can satisfy.

While nuclear power has enjoyed renewed public support in recent years, as reported in several public sources, technology firms including Amazon, Microsoft, Meta, and Google recently announced plans to secure dedicated energy production output from nuclear power plants for their data centers. This includes agreements to build small modular reactors (SMRs) and advanced reactors in several regions.

Expanding the current reactor fleet to meet that level of electrical generating capacity remains a significant challenge to the nuclear industry. To meet those goals, the global industry must protect existing capacity, and there have been multiple public pronouncements from several countries, including the U.S. to protect existing nuclear generating capacity intact. In the U.S., as a result of clean energy credits granted be several states and the production tax credit for nuclear power provided in the Inflation Reduction Act, several nuclear utilities have announced operating life extensions and capacity expansions within their existing operating fleet. Also, the industry has seen a truly unprecedented trend in reactor recommissioning, In the U.S., where just a few years ago reactors were being shut down prematurely, nuclear plants such as Diablo Canyon, Palisades, Three Mile Island, and Duane Arnold are positioned to re-enter service.

Uprates and refurbishments have proven to be exceptionally economical for many reasons, including building on existing licenses and long-established operations. Moreover, several countries have announced plans to abandon plans to exit nuclear power, including Belgium, Japan, and South Korea. And other countries, such as Switzerland, appear to be reconsidering their exits.

There remains continued and growing support for the development of small modular reactors ("SMR"). The case for smaller reactors is largely built on cost savings as well as installation flexibility and scalability. Proponents of SMRs point to standardized design and serial production as the main drivers for reduced costs, with each manufactured unit becoming less expensive than the one before it. SMRs are expected to be smaller and more modular than traditional reactors, so they can be installed in locations would not accommodate larger reactors due to space and location. They can also be used on decommissioned coal power plant sites, which is being looked at as a way to transition to clean electricity.

With increasing demand expectations, there is an expectation that a likewise increase in uranium production must occur in an environment beset by risks, including import bans, sanctions, and secondary sanctions imposed by various countries, transportation issues, trade restrictions in other goods and services beyond nuclear fuel, and fewer available ports, which have all combined to create widespread uncertainty in the market regarding the availability of both current and future supply. The most notable recent trade restriction is the USA's Prohibiting Russian Uranium Imports Act (H.R. 1042), which was signed into law in May 2024 and prohibits the importation of unirradiated, low-enriched uranium produced in the Russian Federation or by a Russian entity. The Act allows temporary waivers, during the period up to January 1, 2028, under certain circumstances.

In response, on November 15, the Russian government imposed "temporary limits" on the export of enriched uranium to the USA, as a retaliatory move following the enactment of the US ban on Russian uranium imports.[3] In September 2024, the U.S. Government announced that it was investigating a significant increase in enriched uranium imported from China when Russian imports were being considered for an outright ban in the context of possible circumvention of the Russian Suspension Agreement.[4] Additionally, in November 2024, the President-elect, Donald Trump declared on social media that he intends to impose a 25 percent tariff on all goods entering the USA from Mexico and Canada on his first day in

office (January 20, 2025). Subsequent to that date, President Trump announced the tariffs will go into effect February 3, 2025. It is unknown the direct impacts these tariffs will have on the uranium market, at this time.

Below is a list of some of the recent government policy news that can influence the uranium market.

- On January 20, 2025, President Trump issued two Executive Orders that specifically refenced nuclear power and uranium as key parts to expanding energy in the U.S. The Executive Order titled, "Unleashing American Energy", in addition to directing federal agencies to advance permitting for energy projects also called for uranium to be designated as a "critical mineral" by the U.S. Geological Survey. The Executive Order titled, "Declaring a National Energy Emergency", that directs federal agencies, under emergency authority, to advance permit and license approvals for the production of energy and energy resources. In that Executive Order, uranium is defined as an "energy resource" and subject to the emergency declaration.
- During the 29th United Nations Climate Change Conference in Baku, Azerbaijan (COP 29), the USA announced new domestic nuclear energy deployment targets and a framework for action, which includes a target of 200 GW of new US nuclear energy capacity by 2050, and outlines pathways and actions to meet this goal. Meeting this target would triple US domestic nuclear energy capacity from current levels.
- Following the enactment of the Nuclear Fuel Security Act in 2024, the US Department of Energy (DOE) selected six companies from which it can sign contracts to procure low-enriched uranium (LEU) in order to incentivize the build-out of new uranium production capacity in the U.S.A. The companies include: American Centrifuge Operating, LLC; General Matter, Inc.; Global Laser Enrichment, LLC; Louisiana Energy Services, LLC; Laser Isotope Separation Technologies, Inc.; and Orano Federal Services; LLC. All contracts will last for up to 10 years and each awardee will receive a minimum contract of U.S. $2 million. The maximum value for all awardees totals $3.4 billion. The final award value will depend on competitive task orders to be subsequently issued by DOE.
- The U.S. Department of Energy (DOE) announced that up to US$80 million is available through a new funding opportunity to spur advancements in the process to produce high-assay low-enriched uranium (HALEU). The funding will support industry partners developing innovative technologies and approaches to strengthening the HALEU supply chain in the USA.

[1] Nuclear Market Review week ending February 2, 2024, TradeTech LLC, 2024
[2] Nuclear Market Review, December 31, 2024, TradeTech LLC, 2024
[3] "Russia Temporarily Limits Enriched Uranium Supplies to US", Bloomberg, November 15, 2024
[4] "Exclusive-US Probes Uranium Imports From China Amid Concerns Over Russian Ban", Reuters, September 17,2024

Sales of Uranium and Sales Agreements

During the year ended December 31, 2024, enCore completed eight uranium sales totaling 720,000 pounds U_3O_8 for an average sales price of $81.02 per pound U_3O_8, not including converter and transaction costs. The Company used 580,000 pounds U_3O_8 was sourced from purchased uranium, and the balance was sourced from uranium produced at the Rosita and Alta Mesa, combined.

To support the Company's development plans, enCore's uranium sales strategy provides a base level of projected income from sales contracts while preserving significant ability to realize opportunities when strong short-term market fundamentals are present. This strategy assures that the Company will have committed sales to support the capital necessary for construction of new projects while maintaining flexibility to be opportunistic as market conditions continue to change in favorable ways.

The Company has been able to use improving uranium market conditions to create a balanced uranium sales agreement portfolio to provide multiple pricing structures to support future market changes and support production plans. As of December 31, 2024, we have executed eleven uranium sales agreements to supply uranium to nuclear power plants in the United States and one legacy uranium sales agreement with a uranium trading company. enCore's uranium sales agreement portfolio is a mix of market related pricing, hybrid base price and market related pricing, base escalated pricing, and fixed prices. Of enCore's twelve (12) current uranium sales agreements, two are market-related with no floors or ceilings, five are market related that typically retain exposure to spot pricing, while including minimum floor and maximum ceiling prices, some of which are adjusted upwards periodically for inflation. Minimum floor prices are set at levels that provide the Company with a comfortable margin over its expected costs of operations in Texas while still allowing the Company to participate in anticipated escalations of the price of uranium. The Company will continue to assess opportunities to secure future sales agreements that will support its continued project and production growth strategies. The Company is committed to honoring all sales commitments. To meet delivery obligations during the year, as uranium extraction increased, the Company occasionally purchased U_3O_8 in the open market to fill those contractual obligations.

As of December 31, 2024, we have 4,455 million pounds U_3O_8 in committed uranium sales from 2025 through 2029. Five of the current contracts provide the optionality to add an additional 1,025 million pounds U_3O_8 through 2029. The annual schedule of contracted sales is shown in the table below:

Delivery Year	Firm Deliveries Pounds U_3O_8	Optional Deliveries Pounds U_3O_8
2024*	720,000	0
2025	680,000	50,000
2026	825,000	95,000
2027	850,000	75,000
2028	800,000	350,000
2029	1,300,000	455,000
Total: (2025 – 2029)	**4,455,000**	**1,025,000**

* Deliveries during period are complete.

Operations Update

The Company is focused on producing uranium in the United States and delivering that uranium to customers. The Company currently utilizes only the proven ISR technology to provide necessary fuel for the generation of clean, reliable, and carbon-free nuclear energy.

enCore owns 3 of the 11 licensed and constructed Central ISR Uranium Processing Plants (CPPs) in the United States. All of its existing facilities are located in the State of Texas. Our plants are designed and permitted to process uranium from a mix of satellite plants and primary sources within South Texas. In addition, the Company has several key mineral resource projects in other jurisdictions within the United States. Our S-K 1300 compliant resources are listed below:

Total measured and indicated Mineral Resources 30.94 million lbs U_3O_8
Total inferred Mineral Resources 20.54 million lbs U_3O_8

The Company's strategy over the next three years is centered around two of its fully licensed Texas CPPs; Rosita and Alta Mesa. The CPPs located at the Rosita and Kingsville Dome projects are designed for, and fully capable of, processing feed resin from relocatable satellite IX plants employed at various deposits within a 100-mile radius of each plant. The Rosita CPP was the starting point for enCore's Texas extraction strategy. In the fourth quarter of 2024, the Company announced it had commenced uranium extraction operations at Rosita from the Rosita Extension wellfield, PAA-5. Rosita is located approximately 60 miles from Corpus Christi, Texas and has an 800,000-pound U_3O_8 per year production capacity. The Rosita CPP will act as the central processing site for the Rosita South - Cadena, Upper Spring Creek- Brown, Upper Spring Creek – Brevard, and Butler Ranch Project.

In February 2023, the Company acquired 100% of the Alta Mesa Uranium Project and the Mesteña Grande Uranium Project from Energy Fuels for $120 million. enCore's fully licensed Alta Mesa CPP is located approximately 100 miles southeast of Corpus Christi, TX, and has a production capacity of 1.5 million pounds ofU_3O_8 per year through its IX exchange system located at the plant. The facility has IX elution, precipitation, drying, and packaging capacity for 2.0 million pounds of U_3O_8 per year. This capacity is designed to accept direct production feed to the IX columns in the plant and concurrently accept loaded resin from satellite locations. The Alta Mesa Project includes existing and near-term production areas, including the fully permitted and authorized production areas 6 and 7. The Mesteña Grande Uranium Project also has nine additional mineral resource areas described below in the "Our Item 1 and 2. Our Business and Properties, Mesteña Grande Project" section. In total, the Alta Mesa Uranium Project combined with the Mesteña Grande Uranium Project encompasses mineral leases on 200,000 acres of private land. In February 2024, the Company sold a 30% interest in the Alta Mesa and Mesteña Grande projects to Boss for $60 million.

In June 2024, the Company announced the successful startup of uranium extraction operations at the Alta Mesa Alta Mesa Project. With the restart of the previously operating Alta Mesa Project, the Company is now the only uranium producer in the United States with multiple production facilities in operation as of December 31, 2024. The initial ramp up will be a progressive process to advance and continually increase uranium extraction via direct feed to the Alta Mesa CPP. Exploration drilling and wellfield installation continued at Wellfield 7 at Alta Mesa to support expanding extraction rate capacity through a second IX circuit at the Alta Mesa CPP. During the year ended December 31, 2024, wellfield solution head grades at the Alta Mesa Project peaked at approximately 140 mg/L U_3O_8 and averaged approximately 54 mg/L U_3O_8.

During the year ended December 31, 2024, the Company continued operations at its Rosita CPP, and it announced in June 2024, the start of uranium extraction at its Alta Mesa CPP location. For both the Rosita CPP and the Alta Mesa CPPs combined, 286,624 pounds U_3O_8 were captured on ion exchange resin and 236,891 pounds U_3O_8 were dried and packaged from our Rosita Project and Alta Mesa Project, combined over the year ended December 31, 2024. Additionally, over the same period, the Company shipped 234,842 pounds U_3O_8 to a North American conversion facility. In 2024, Boss received 35,181 pounds U_3O_8 for uranium product shipped on the behalf of the joint venture to a North American conversion facility.

Thorough the year, the Company focused on starting up its uranium recovery operations at its Rosita CPP and at its Alta Mesa CPP. During 2024, as the Company executed its plans at its Rosita and Alta Mesa CPP's and related wellfields, operational performance met expectations, in general. There were some operational challenges that were observed by the Company that impacted uranium recovery. The Company experienced lower extraction rates of in-situ mineral resources due to wellfield pattern inefficiencies caused by incomplete geophysical data and construction. At the time, limited and unreliable PFN capabilities contributed to these challenges. The acquisition of additional PFN equipment, parts, and

intellectual property enabled the Company to mitigate these inefficiencies for current wellfields at Alta Mesa and future South Texas Satellite IX wellfields that will supply the Rosita CPP.

At the Alta Mesa Project, uranium extraction from Wellfield 7 progressed faster than planned, outpacing wellfield replacement due to a limited number of drilling rigs in operation at the time. Additionally, the accelerated pace of activity revealed gaps in coordination across wellfield construction, infrastructure installation, and operations, further delaying replacement and the development of additional wellfield patterns to support the expanded capacity at the Alta Mesa CPP. By late Q4, the Company increased its drilling rig count from six in Q1 2024 to 17, and implemented organizational changes to enhance coordination and improve efficiency in wellfield extraction.

The Kingsville Dome CPP is currently maintained in a standby condition. This facility, similar in size and design to the Rosita facility, has a capacity of 800,000 pounds of U_3O_8 per year.

As the Company has been increasing its' operational pace to meet our targets for uranium extraction rates, we have successfully increased our drilling rig capacity to facilitate replacing mineral resource depletion and adding mineral resources in South Texas. The Company started with six (6) active drilling rigs in South Texas at the beginning of 2024, and in the last half of the year, the number of active drilling rigs in South Texas increased to seventeen (17). Additionally, the Company had two active drilling rigs operating in Wyoming in the second half of the year. Additionally, enCore has an experienced technical team with years of experience in ISR operations in Texas, Wyoming, and Nebraska supporting and managing our operations. We have been able to utilize that experience and "know how" to self-execute the refurbishment of the Rosita and Alta Mesa CPP, along with design, construct and install infrastructure for three wellfields and two satellite IX facilities over the period of three years.

South Texas Regulatory Proceedings

Each of the Company's production facilities maintain several permits and licenses in order to manage the current operations. For all of the Company's operating locations, all permits and licenses remain current and in effect. In some cases, some of those permits and licenses are in renewal, and for some expansion activities, new permits or amendments will be necessary. All of our South Texas facilities are regulated by the TCEQ in the case of in-situ uranium recovery and underground injection operations, and for exploration and development drilling activities, the TRC is the principal regulator. The Radioactive Materials Licenses for Rosita and Alta Mesa are issued by the TCEQ under the NRC Agreement State program that assures that mature and consistent regulatory process is in place to assure more certainty regarding regulatory approvals.

As previously disclosed, there are no permits or license amendments required to execute the Alta Mesa uranium extraction rate ramp up. Currently, at Alta Mesa, the Radioactive Materials License and the Class III UIC Area Permit are in timely renewal and under technical review by the TCEQ, but those do not effect current expansion activities. At Upper Spring Creek, the TCEQ has issued the Class III UIC Area Permit, and the agency is completing the technical review of the License Amendment to the Rosita Radioactive Materials License that incorporates the Upper Spring Creek wellfield and satellite IX facility into the current license activities. This approval of the license amendment is necessary to advance wellfield and satellite IX construction, and the progress on approval remains within schedule expectations.

South Dakota Developments

In addition to the Company's operations in South Texas, it is also developing pipeline projects in other states. Notably, the advanced stage Dewey-Burdock Uranium Project in South Dakota has demonstrated ISR resources, including a 2024 S-K 1300 Technical Report Summary and N.I. 43-101 Technical Report and Preliminary Economic Assessment ("PEA") citing robust economics. The project has its source material license from the NRC and its underground injection permits and aquifer exemption from the EPA. In 2023, the Company announced that the NRC approval was considered final when appeals of the license approval were exhausted following a successful outcome from the Circuit Court of Appeals for the District of Columbia. In April 2024, the Company submitted its application to renew the ten (10) year old Source Material License, SUA-1600. The NRC has confirmed that the Dewey-Burdock Source Material License is in timely renewal. The underground injection permits were appealed to the EPA's Environmental Appeals Board ("EAB") and the aquifer exemption was appealed to the 8th Circuit Court of Appeals. In September 2024, the Company provided an update regarding the EAB appeal, including a ruling denying the intervenors contentions on the merits, and remanded to the EPA to review and complete, if necessary, the administrative record for its permit decisions. Based on the successful outcome for the company of the appeal of the NRC license, the Company believes it will be successful in the appeals of the EPA's underground injection permits and the aquifer exemption.

Wyoming Developments

The Company has also commenced the initial permitting work to advance the Gas Hills Project as an ISR uranium recovery operation located in central Wyoming, approximately 60 miles west of Casper, Wyoming. As part of the initial data collection for project permitting, the Company initiated core drilling during the year ended December 31, 2024. Gas Hills Project is located in the historic Gas Hills Uranium Mining District, a brownfield area of extensive previous mining.

Also, in Wyoming, the Company initiated exploration drilling to expand the project area at its Dewey Terrace Project area. The uranium orebody that consists of the Dewey-Burdock Uranium Project extends into Wyoming from South Dakota. Historically, the Company has designated the ore body extension into Wyoming as its Dewey Terrace Project.

Results of Operations:

Year Ended December 31, 2024 Compared to Year Ended December 31, 2023

The following table summarizes the results of operations for the years ended December 31, 2024 and 2023:

	Year ended December 31,			
(in thousands except per share data)	2024 $	2023 $	Increase (Decrease)	Percent Change
Revenue	58,334	22,148	36,186	163%
Cost of goods sold	65,541	19,573	45,968	235%
Operating expenses, excluding stock option expense	60,188	39,834	20,354	51%
Stock option expense	4,788	3,464	1,324	38%
Interest income	2,476	393	2,083	530%
Interest expense	(1,735)	(3,503)	1,768	(50)%
Gain on sale of mineral interests	-	11,837	(11,837)	(100)%
Gain (loss) on marketable securities, unrealized	(2,711)	5,918	(8,629)	(146)%
Gain on marketable securities, realized	248	-	248	100%
Other expense	(17)	-	(17)	100%
Net loss before income taxes	(73,922)	(26,078)	(47,844)	183%
Basic and diluted loss per share	(0.34)	(0.18)	(0.16)	89%

The following table sets forth selected operating data and financial metrics for uranium sales for the years ended December 31, 2024 and 2023.

	Year Ended December 31,		Increase	Percent
	2024	2023	(Decrease)	Change
Volumes sold (lbs)	720,000	400,000	320,000	80%
Realized sales price ($/lb)	81.0	55.4	25.6	46%
Costs applicable to revenues ($/lb)	91.0	48.9	42.1	86%

- Revenue from uranium sales for the year ended December 31, 2024 was $58,334 compared to revenue of $22,148 for the year ended December 31, 2023, an increase of $36,186. The increase was due to the completed sale of 720,000 pounds of uranium, compared to sales of 400,000 pounds of uranium during the year ended December 31, 2023. The realized sales prices per pound of uranium for the periods ended December 31, 2024 and 2023 were $81.0 and $55.4, respectively, and includes the contractual sales price less sales-related costs such as transfer fees. The realized sale price per pound decrease is dictated by the market for uranium, which is a commodity.

- Costs applicable to uranium sales were $65,541 for the year ended December 31, 2024 related to the completed sale of 720,000 pounds of uranium at a weighted average cost of $91.0 per pound compared to uranium costs of $19,573 for the sale of 400,000 pounds at a weighted average cost of $48.9 per pound for the year ended December 31, 2023. The increase in costs was due to higher volume of uranium sold, purchases of uranium at a

higher market price than year-end as well as an impairment loss of $6,054 in 2024. The Company's weighted average cost components include the cost of purchased uranium and uranium from extraction.

- Operating expenses, excluding stock option expenses, for the year ended December 31, 2024, were $60,188 as compared to $39,834 for the year ended December 31, 2023. This increase primarily reflects the growth and increased activity levels the Company experienced in 2024 driven primarily by the extraction of uranium at Alta Mesa and Rosita which commenced in 2024.

- The Company recognized a loss of $2,711 on the fair value of marketable securities for the year ended December 31, 2024, compared to a gain of $5,918 for the year ended December 31, 2023. Unrealized losses for the twelve months ended December 31, 2024, are due to unfavorable market conditions during 2024.

- Interest expense for the year ended December 31, 2024, and December 31, 2023, was $1,735 and $3,503, respectively. This reduction is attributable to the Company's debt pay down of $40,000 in 2023 and conversion of the $60,000 convertible promissory note in February 2024, partially offset by interest expense on the uranium loan in 2024.

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022

The following table summarizes the results of operations for the years ended December 31, 2023 and 2022:

(in thousands except per share data)	Year ended December 31, 2023 $	2022 $	Increase (Decrease)	Percent Change
Revenue	22,148	4,245	17,903	422%
Cost of goods sold	19,573	2,656	16,917	637%
Operating expenses, excluding stock option expense	39,834	23,168	16,666	72%
Stock option expense	3,464	4,332	(868)	(20)%
Interest income	393	419	(26)	(6)%
Interest expense	(3,503)	-	(3,503)	100%
Foreign exchange loss	-	(58)	58	(100)%
Gain on sale of mineral interests	11,837	1,852	9,985	539%
Gain on marketable securities, unrealized	5,918	1,057	4,861	460%
Other expense	-	(679)	679	(100)%
Net loss before income taxes	(26,078)	(23,320)	(2,758)	12%
Basic and diluted loss per share	(0.18)	(0.22)	0.04	(18)%

The following table sets forth selected operating data and financial metrics for uranium sales for the years ended December 31, 2023 and 2022.

	Year ended December 31, 2023	2022	Increase (Decrease)	Percent Change
Volumes sold (lbs)	400,000	100,000	300,000	300%
Realized sales price ($/lb)	55.4	42.5	12.9	30%
Costs applicable to revenues ($/lb)	48.9	26.6	22.3	84%

- Revenue from uranium for the year ended December 31, 2023 was $22,148 an increase of $17,903 due to the completed sale of 400,000 pounds of uranium, compared to sales of 100,000 pounds of uranium during the year ended December 31, 2022. The realized sales prices per pound of uranium for the periods ended December 31, 2023 and 2022 were $55.4 and $42.5, respectively, and includes the contractual sales price less sales related costs such as transfer fees. The realized sale price per pound increase is dictated by the market for uranium, which is a commodity. The realized sale price per pound increase is dictated by the market for uranium, which is a commodity.

- Costs applicable to uranium were $19,573 for the year ended December 31, 2023 related to the completed sale of 400,000 pounds at a weighted average cost of 48.9 per pound compared to uranium costs of $2,656 for the sale of 100,000 pounds at a weighted average cost of $26.6 per pound for the year ended December 31, 2022. The increase in costs was primarily due to higher volume of uranium sold in 2023 as well as an increase in the price of Uranium that was purchased when compared to 2022.

- Operating expenses, excluding stock option expense, for the year ended December 31, 2023, were $39,834 as compared to $23,168 for the year ended December 31, 2022. This increase primarily reflects the growth and increased activity levels the Company experienced in 2023.

- Unrealized gains recognized on the fair value of marketable securities for year ended December 31, 2023, were $5,918 compared to a gain of $1,057 for the year ended December 31, 2022. This is primarily due to unrealized gain at Premier American Uranium in 2023 partially offset by losses in Anfield and Nuclear Fuels.

- Interest expense for the year ended December 31, 2023 was $3,503 attributable to interest on the Company's issuance of a $60,000 convertible promissory note in February 2023. The Company did not incur interest expense during the year ended December 31, 2022.

Non-GAAP Financial Measures

We present non-GAAP financial measures of total cost of extracted pounds and uranium cost per extracted pound during the reporting period. Total cost of extracted pounds is the cost of sales less the cost of sales of purchased goods, which includes the aggregate purchase price of uranium sourced from purchased uranium. Uranium cost per extracted pound is the total cost of extracted pounds divided by the pounds of uranium extracted during the period. We believe the total cost of extracted pounds and uranium cost per extracted pound, including allocation of cash and non-cash costs, assist investors in evaluating the efficiency and cost-effectiveness of the Company's extraction process and overall cost structure and financial performance. In addition, management uses these non-GAAP measures to evaluate the ongoing operations and for internal planning and forecasting.

During the year ended December 31, 2024, the Company continued its uranium extraction activities at its South Texas operations.

U_3O_8 Costs		Units	2024 Cost of Sales
Cost of sales		$	$65,541
Less the cost of sales of purchased pounds		$	$58,433
Cash costs of extracted pounds	1	$	$6,304
Non-cash costs of extracted pounds	2	$	$804
Total cost of extracted lbs		$	$7,108

U_3O_8 Pounds		
Total pounds		755,181
Purchased	lbs	580,000
Extracted	lbs	175,181
Shipped to Boss	lbs	(35,181)
Net enCore	lbs	720,000

U_3O_8 Cost per Pound		
Total pounds	$	86.79
Less purchased	$	100.75
Cash costs of extracted lbs	$	35.99
Non-cash costs of extracted lbs	$	4.59
Total extracted	**$**	**40.57**

1 The cash costs associated with extracted pounds related to cost of goods sold serve as a key metric for investors in evaluating the efficiency and cost-effectiveness of the Company's extraction operations.

2 The non-cash costs associated with extracted uranium cost of goods sold provide investors with insight into additional expenses that impact overall cost structure and financial performance.

The Company remains committed to cost efficiency and production optimization, ensuring competitive uranium extraction and processing. The Company anticipates further cost efficiencies as additional wellfield patterns come online and economies of scale improve.

Liquidity and Capital Resources

Our short-term cash requirements are primarily driven by exploration and development activities aimed at advancing properties for uranium extraction. We expect to meet our short-term cash requirements generally through existing working capital. As of December 31, 2024 and December 31, 2023, the Company had cash and cash equivalents of $39,701 and

$7,493, respectively, and working capital of $57,334 and $19,038, respectively. Operations to date have been funded primarily from the issue of share capital.

Our long-term cash requirements are also primarily driven by exploration and development activities aimed at advancing properties for uranium extraction. We expect to meet our long-term cash requirements through various sources of capital, which may include a revolving credit facility or line of credit and future debt or equity issuances, existing working capital, net cash provided by operations and property dispositions. However, there are a number of factors that may have a material adverse effect on our ability to access these capital sources, including the state of overall equity and credit markets, our degree of leverage, our unencumbered asset base and borrowing restrictions imposed by lenders (including as a result of any failure to comply with financial covenants in future indebtedness), general market conditions for uranium mining companies and other energy companies, our operating performance and liquidity and market perceptions about us. The success of our business strategy will depend, in part, on our ability to access these various capital sources.

We believe that our available cash, expected operating cash flows, and potential debt or equity financings will provide sufficient funds for our operations, anticipated scheduled debt service payments and dividend requirements for the twelve-month period following December 31, 2024. We believe that our sources of long-term cash will be sufficient for our needs thereafter.

On February 26, 2024, enCore and Boss entered into a note payable providing for up to 200,000 pounds of uranium to be lent by Boss to enCore. The loan will bear interest of 9% and be repayable in 12 months. Under the agreement, enCore may prepay the loan in full or part after six months and would be subject to a prepayment fee of $200. Both the prepayment and the prepayment fee can be paid in cash or uranium at the election of Boss Energy.

Cash Flows

The following table reflects cash flows activities for the year ended December 31, 2024 and 2023:

	Year Ended December 31,		
	2024	**2023**	**Increase (Decrease)**
Net cash used in operating activities	$ (45,204)	$ (22,987)	$ (22,217)
Net cash used in investing activities	(29,990)	(64,617)	34,627
Net cash provided by financing activities	107,417	45,901	61,516
Impact of currency rate changes in cash	56	(205)	261
Net decreases in cash and cash equivalents	$ 32,279	$ (41,908)	$ 74,187

Net Cash Used in Operating Activities

Net cash used in operating activities increased by $22,217, to $45,204, for the year ended December 31, 2024, compared to the year ended December 31, 2023. This is largely driven by increase in expenditures driven by the Company's commencement of extraction activities for Alta Mesa and Rosita in 2024.

Net Cash Used in Investing Activities

Net cash used in investing activities decreased by $34,627, to $29,990, for the twelve months ended December 31, 2024, compared to the twelve months ended December 31, 2023. This was largely driven by the Company's asset acquisition of Alta Mesa in 2023, offset by the Company's purchase of marketable securities in 2024.

Net Cash Provided by Financing Activities

Net cash provided by financing activities increased by $61,516, to $107,417 for the twelve months ended December 31, 2024, compared to the fiscal year ended December 31,2023. This was largely driven by the Company's sale of a minority interest (30%) in JV Alta Mesa in 2024 as well as an increase in warrant exercises when compared to 2023. This was offset by a reduction in equity financings that occurred in 2024 when compared to 2023.

Commitments

The Company has entered into several contracts with traders and nuclear utilities to sell pounds of uranium through 2033.

The Company's sales commitments in pounds are shown below.

Year	Volume (in pounds)
2025	680,000
2026	825,000
2027	850,000
2028	800,000
2029	1,300,000
Thereafter	2,500,000
Total	6,955,000

The Company did not have significant contractual obligations as of December 31, 2024. except for the sales commitments discussed above.

Off Balance Sheet Arrangements

As of December 31, 2024, the Company had no material off-balance sheet arrangements such as guarantee contracts, contingent interest in assets transferred to an entity, derivative instruments obligations or any obligations that trigger financing, liquidity, market or credit risk to the Company.

Critical Accounting Policies and Estimates

Our consolidated financial statements have been prepared in accordance with U.S. GAAP. Preparation of the financial statements requires us to make judgments, estimates and assumptions that impact the reported amount of net sales and expenses, assets and liabilities and the disclosure of contingent assets and liabilities. We consider an accounting judgment, estimate or assumption to be critical when the estimate or assumption is complex in nature or requires a high degree of judgment and when the use of different judgments, estimates and assumptions could have a material impact on our consolidated financial statements. While our significant accounting policies are described in more detail in Note 2 of our consolidated financial statements, we believe that the following accounting policies are those most critical to the judgments and estimates used in the preparation of our financial statements.

Estimates are based on management's best knowledge of current events and actions that the Company may undertake in the future. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

Impairment of Long-lived Assets: The Company reviews and evaluates its long-lived assets for impairment when events or changes in circumstances indicate that the related carrying amounts may not be recoverable. Mineral rights and properties and mining properties are monitored for impairment based on factors such as uranium prices, government regulations, our continued right to explore the area, exploration reports, assays, technical reports, drill results and our continued plans to fund exploration and development programs on the property.

Asset Retirement Obligations: Various federal and state mining laws and regulations require our Company to reclaim the surface areas and restore underground water quality to the pre-existing quality or class of use after the completion of mining. We recognize the present value of the future restoration and remediation costs as an asset retirement obligation in the period in which we incur an obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development and/or normal use of the assets.

Asset retirement obligations consist of estimated final well closure, plant and equipment decommissioning and removal and environmental remediation costs to be incurred by our Company in the future. The asset retirement obligation is estimated based on the current costs escalated at an inflation rate and discounted at a credit adjusted risk-free rate at inception. The asset retirement obligations are capitalized as part of the costs of the underlying assets and amortized over its remaining useful life. The asset retirement obligations are accreted to an undiscounted value until they are settled. The accretion

expenses are charged to earnings and the actual retirement costs are recorded against the asset retirement obligations when incurred.

Asset Acquisitions: The Company performs a screen test as required under U.S. GAAP to determine whether a transaction is an asset acquisition under FASB ASC Topic 805, Business Combination. If substantially all of the fair value of gross assets acquired is concentrated in a single identifiable asset (or a group of similar identifiable assets), the assets acquired would not represent a business and we account for the acquisition as an asset acquisition. In addition, when an acquisition does not meet the definition of a business combination as the acquired entity does not have an input and a substantive process that together significantly contribute to the ability to create outputs, we also account for the acquisition as an asset acquisition. In an asset acquisition, any direct acquisition-related transaction costs are capitalized as part of the purchase consideration. Deferred taxes are recorded on temporary book/tax differences in an asset acquisition using the simultaneous equations method and adjusting the assigned value of the non-monetary assets acquired to include the deferred tax liability. There is no goodwill recorded, with any excess purchase price being allocated on a pro-rata basis to the acquired assets based on their relative fair values.

Income Taxes: The Company uses the asset and liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recorded based on differences between the financial statement carrying values of existing assets and liabilities and their respective income tax bases (temporary differences), and losses carried forward. Deferred income tax assets and liabilities are measured using the enacted tax rates which will be in effect when the temporary differences are likely to reverse. The effect on deferred income tax assets and liabilities of a change in tax rates is included in operations in the period in which the change is enacted.

The Company records a valuation allowance to reduce deferred income tax assets to the amount that is believed more likely than not to be realized. When the Company concludes that all or part of the deferred income tax assets are not realizable in the future, the Company makes an adjustment to the valuation allowance that is charged to income tax expense in the period such determination is made.

Conversion from IFRS to U.S. GAAP

As the Company no longer qualifies as a foreign private issuer, its consolidated financial statements have been retroactively converted from IFRS to U.S. GAAP.

The significant differences between IFRS and U.S. GAAP as they relate to the Company are as follows:

{a} Exploration and Development Costs

Under IFRS, the Company capitalized exploration and development costs related to the Company's Mineral Properties. Under US GAAP, the Company is only eligible to capitalize costs related to the following for Mineral Properties;

- Asset Acquisitions
- Direct Development Costs after establishing proven/probable reserves. This requires obtaining a S-K 1300 that supports the existence of probable or proven mineral reserves. As of December 31, 2024, the Company's S-K 1300s do not indicate proven/probable reserves. Therefore, the Company remains an Exploration Stage Issuer and is unable to capitalize development costs.

Exploration costs, land lease costs and development costs are expensed as incurred for the years ended December 31, 2024, 2023, and 2022, respectively.

{b} Income Taxes

The Company recorded a deferred tax liability under U.S GAAP as a result of the Azarga asset acquisition. Under U.S GAAP, this requires book basis increase for the change in fair value. However, there is no tax basis bump related to the Azarga asset acquisition. This results in a difference that requires a deferred tax liability under U.S. GAAP ASC 740, Income Taxes. Under IFRS, this does not result in a deferred tax liability.

{c} Share-based Compensation

Under IFRS, the Company utilized the expected term for share-based compensation in the Black-Scholes valuation calculation. The Company under U.S. GAAP elected the simplified method for 'vanilla' stock options, as permitted by the SEC. This allows the average between the vesting period and the contractual period to be utilized for the expected term.

{d} Investments in Uranium
Under IFRS, the Company treated its purchases of uranium as investment property. Under IFRS, the Company adjusted its inventory to the fair market value as of each reporting period and upon sale, recorded the sale as a non-operating gain. Under U.S. GAAP, the Company treated its purchases of Uranium as inventory, which is held at the lower of carrying value and net realizable value. This resulted in reclassification of the income statement impacts to revenue and cost of goods sold and the deferral of gain/loss on the changes in the fair market value of uranium until the uranium was sold to customers.

{e} Warrants granted in Conjunction with Equity Financing

Under IFRS, the Company allocated the proceeds received from warrants granted in conjunction with equity financing to common stock. Under US GAAP, the proceeds received are required to be applied to the warrants and the share issuance based on their relative fair value. This results in a higher additional paid in capital balance upon the granting of the warrants than under IFRS and a lower amount attributed to common stock than under IFRS.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Our exposure to market risks includes, but is not limited to, equity price risk, uranium price risk and foreign currency risk.

Equity Price Risk

We are subject to market risk related to the market price of our common shares, which trade on Nasdaq and TSX-V. Historically, we have relied upon equity financings from the sale of our common shares to fund our operations. Movements in the price of our common shares have been volatile in the past and may continue to be volatile in the future. As a result, there is a risk that we may not be able to complete an equity financing at an acceptable price when required.

In addition, we have investments in equity securities, which are common shares and warrants of publicly listed companies. Movements in the price of these equity securities have been volatile in the past and may continue to be volatile in the future.

Uranium Price Risk

We are subject to market risk related to the market price of uranium. As of December 31, 2024, we had no uranium supply or off-take agreements in place. Since future sales of uranium concentrates are contracted based on both spot and fixed pricing, fluctuations in the market price of uranium would have a direct impact on our revenues, results of operations and cash flows. We do not use derivative financial instruments for speculative trading purposes, nor do we hedge our uranium price exposure to manage our uranium price risk.

Foreign Currency Risk

We are subject to market risk related to foreign currency exchange rate fluctuations. Our functional currency is the United States Dollar, however, a portion of our business is transacted in other currencies including the Canadian Dollar. To date, these fluctuations have not had a material impact on our results of operations.

We do not use derivative financial instruments for speculative trading purposes, nor do we hedge our foreign currency exposure to manage our foreign currency fluctuation risk.

Item 8. Financial Statements and Supplementary Data (For 10-K, this should be Audited Financial Statements)

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Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
enCore Energy Corporation:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of enCore Energy Corporation and subsidiaries (the Company) as of December 31, 2024 and 2023, the related consolidated statements of operations, comprehensive loss, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2024, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2024, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2024, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 3, 2025 expressed an adverse opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of a critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Asset retirement obligation costs

As discussed in Note 11 to the consolidated financial statements, the Company recorded an asset retirement obligation (ARO) liability of $16.9 million as of December 31, 2024. Asset retirement obligations consist of estimated final well closure, plant and equipment decommissioning and removal, and environmental remediation costs to be incurred by the Company in the future. The asset retirement obligation is estimated based on the current costs adjusted for inflation and then discounted at a credit adjusted risk-free rate at inception.

We identified the evaluation of the future costs for asset retirement obligations as a critical audit matter. Specialized skills and knowledge were required to evaluate the Company's determination of asset retirement obligations and their related costs to satisfy the ARO.

The following are the primary procedures we performed to address this critical audit matter. We tested the determination of the planned asset retirement obligations used in the estimate by inquiring of management and inspecting cost calculations approved and permitted by regulatory agencies. We involved environmental professionals with specialized skills and knowledge, who assisted in evaluating the Company's planned asset retirement obligations for certain sites, including comparing the Company's planned asset retirement obligations to those communicated to regulatory authorities.

/s/ KPMG LLP

We have served as the Company's auditor since 2024.

Houston, Texas
March 3, 2025

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
enCore Energy Corporation:

Opinion on Internal Control Over Financial Reporting
We have audited enCore Energy Corporation and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2024, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, because of the effect of the material weaknesses, described below, on the achievement of the objectives of the control criteria, the Company has not maintained effective internal control over financial reporting as of December 31, 2024, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2024 and 2023, the related consolidated statements of operations, comprehensive loss, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2024, and the related notes (collectively, the consolidated financial statements), and our report dated March 3, 2025 expressed an unqualified opinion on those consolidated financial statements.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the Company's annual or interim financial statements will not be prevented or detected on a timely basis. Material weaknesses due to control deficiencies in general information technology controls and process-level controls across financial reporting processes were caused by an ineffective control environment that resulted in ineffective risk assessment, information and communication, and monitoring, which have been identified and included in management's assessment. The material weaknesses were considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2024 consolidated financial statements, and this report does not affect our report on those consolidated financial statements.

Basis for Opinion
The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting
A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

/s/ KPMG LLP
Houston, Texas
March 3, 2025

enCore Energy Corp
Consolidated Balance Sheets

(in thousands except per share data)	December 31, 2024	December 31, 2023
ASSETS		
Current assets		
Cash and cash equivalents	$ 39,701	$ 7,493
Prepaid expenses and other current assets	2,700	931
Marketable securities	24,046	16,886
Inventory	20,967	9
Total current assets	87,414	25,319
Mineral rights and properties, net	271,922	274,490
Property, plant and equipment, net	24,017	14,970
Intangible assets, net	471	514
Restricted cash	7,751	7,680
Marketable securities, non-current	837	3,047
Right of use assets - operating lease	310	459
Other long-term assets	-	88
Total assets	$ 392,722	$ 326,567
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 7,464	$ 3,582
Accounts payable - related parties	2,378	2,521
Note payable - related party	20,108	-
Operating lease liabilities, current	130	178
Total current liabilities	30,080	6,281
Deferred tax liabilities	26,980	27,959
Asset retirement obligations	16,918	10,828
Convertible promissory note	-	19,239
Operating lease liabilities, non-current	202	294
Total liabilities	74,180	64,601
Commitments and contingencies (Note 12)		
Stockholders' equity		
Common stock 186,114,948 and 165,133,798 shares issued and outstanding as of December 31, 2024 and 2023, respectively	380,325	308,198
Equity portion of convertible promissory note	-	3,813
Additional paid-in-capital	59,856	41,203
Accumulated deficit	(150,848)	(89,456)
Accumulated other comprehensive loss	(3,597)	(1,792)
Total stockholders' equity	285,736	261,966
Non-controlling interests	32,806	-
Total equity	318,542	261,966
Total liabilities and stockholders' equity	$ 392,722	$ 326,567

enCore Energy Corp
Consolidated Statements of Operations

(in thousands except per share data)	Years Ended December 31, 2024	2023	2022
Revenue	$ 58,334	$ 22,148	$ 4,245
Cost of sales	65,541	19,573	2,656
Gross profit (loss)	(7,207)	2,575	1,589
Operating costs:			
Mineral property expenditures	29,763	14,224	10,054
General and administrative	27,056	19,914	12,378
Depreciation, amortization and accretion	3,369	5,696	736
Other operating costs	4,788	3,464	4,332
Total operating expenses	64,976	43,298	27,500
Operating loss	(72,183)	(40,723)	(25,911)
Gain on marketable securities, realized	248	-	-
Interest income	2,476	393	419
Interest expense	(1,735)	(3,503)	-
Gain on sale of mineral properties	-	11,837	1,852
Gain (loss) on marketable securities, unrealized	(2,711)	5,918	1,057
Foreign exchange loss	-	-	(58)
Other expense	(17)	-	(679)
Loss before income taxes	(73,922)	(26,078)	(23,320)
Income tax benefit	(5,929)	(467)	(165)
Net loss	(67,993)	(25,611)	(23,155)
Net loss attributable to noncontrolling interests	(6,601)	-	-
Net loss attributable to controlling interest	$ (61,392)	$ (25,611)	$ (23,155)
Net loss per share			
Basic	$ (0.34)	$ (0.18)	$ (0.22)
Diluted	$ (0.34)	$ (0.18)	$ (0.22)
Weighted average number of shares			
Basic	181,982,829	144,043,709	105,529,292
Diluted	181,982,829	144,043,709	105,529,292

enCore Energy Corp
Consolidated Statements of Comprehensive Loss

(in thousands except per share data)	Years Ended December 31, 2024	2023	2022
Net loss	$ (67,993)	$ (25,611)	$ (23,155)
Other comprehensive loss, [net of tax]			
Foreign currency translation adjustment	(1,805)	393	(1,457)
Total other comprehensive loss, [net of tax]	(1,805)	393	(1,457)
Comprehensive loss	(69,798)	(25,218)	(24,612)
Comprehensive loss attributable to non-controlling interests	(6,601)	-	-
Comprehensive loss attributable to stockholders	$ (63,197)	$ (25,218)	$ (24,612)

enCore Energy Corp
Consolidated Statements of Cash Flow

(In thousands)	Years Ended December 31, 2024	2023	2022
Cash used in operating activities			
Net loss	$ (67,993)	$ (25,611)	$ (23,155)
Adjustments to reconcile net income to cash provided by (used in) operating activities			
Amortization, depreciation, accretion and depletion	4,596	5,664	736
Stock based compensation	4,788	3,464	4,332
Shares issued for services	-	-	611
Inventory impairment charge	6,054	-	-
Asset retirement obligation (gain)/loss	5,424	(221)	157
Gain on sale of mineral properties	-	(11,837)	(1,852)
Exploration costs related to mineral properties (investing activity)	9,392	8,205	4,302
Unrealized loss/(gain) on marketable securities	2,711	(5,918)	(1,057)
Loss on equity method investments	-	-	564
Realized gain on marketable securities	(248)	-	-
Changes in operating assets and liabilities:			
Receivables, prepaids and deposits	(10)	356	(618)
Inventories	(7,575)	2,991	(344)
Accounts payable and accrued liabilities	4,079	14	(4,242)
Asset retirement obligations	(399)	(291)	(11)
Deferred tax liability	(5,968)	(469)	(167)
Due to related parties	(55)	666	434
Net cash used in operating activities	$ (45,204)	$ (22,987)	$ (20,310)
Cash used in investing activities			
Purchase of property, plant, and equipment	(11,348)	(7,727)	(980)
Acquisition of Alta Mesa net of cash received and deposit paid	-	(52,212)	(6,009)
Acquisition of intangible assets	-	-	(55)
Exploration costs related to mineral properties	(9,392)	(8,205)	(4,302)
Proceeds from the sale of mineral properties	-	3,527	48
Purchase of marketable securities	(9,798)	-	-
Proceeds from sale of marketable securities	548	-	-
Net cash used in investing activities	$ (29,990)	$ (64,617)	$ (11,298)
Cash provided by financing activities			
Private placement proceeds	10,000	25,562	24,002
Common stock issuance costs	(50)	(4,631)	(1,534)
Stock subscriptions received	-	-	51,559
Proceeds from the At -the-Market ("ATM") sales	2,008	49,444	-
Proceeds from exercise of warrants	25,471	14,968	2,453
Proceeds from exercise of stock options	1,760	558	1,193
Repayments on convertible note	-	(40,000)	-
Financing costs incurred	-	-	(1,717)
Proceeds from sale of minority interest	60,000	-	-

enCore Energy Corp
Consolidated Statements of Cash Flow (continued)

Contributions from non-controlling interest	8,228	-	-
Net cash provided by financing activities	$ 107,417	$ 45,901	$ 75,956
Net increase (decrease) in cash, cash equivalents and restricted cash	32,223	(41,703)	44,348
Foreign exchange difference on cash, cash equivalents and restricted cash	56	(205)	(972)
Cash, cash equivalents and restricted cash, beginning of year	15,173	57,081	13,705
Cash, cash equivalents and restricted cash, end of year	$ 47,452	$ 15,173	$ 57,081

enCore Energy Corp
Consolidated Statements of Cash Flow (continued)

	Years Ended December 31,		
	2024	2023	2022
Non-cash financing activities:			
Share issue costs on finders' warrants issued	$ -	$ 1,485	$ -
Conversion of subscriptions to shares	-	33,300	-
Warrants issued in conjunction with subscription	-	18,259	-
Financing costs remaining in accounts payable and accrued liabilities	-	-	1,513
Conversion of promissory note, including equity portion, to shares	23,117	-	-
Inventory received in exchange for note payable	20,108	-	-
Inventory distributions to non-controlling interest	1,905	-	-
Unpaid contributions from non-controlling interest	1,759	-	-
Fair value of Alta Mesa replacement options granted for asset acquisition	-	81	-
Marketable securities obtained as part of sale of mineral property	-	9,815	3,345
Non-cash investing activities:			
Property, plant, and equipment additions included in accounts payable and accrued liabilities	-	188	-
Convertible promissory note Issued for asset acquisition	-	60,000	-

6.

enCore Energy Corp
Consolidated Statements of Stockholders' Equity

(in thousands except per share data)	Common Stock Shares	Common Stock Amount	Subscription Receivable	Equity Portion of Convertible Promissory Note	Additional Paid-in-Capital	Accumulated Deficit	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Total Equity
Balance at January 1, 2022	**98,903**	**$163,528**	**$ -**	**$ -**	**$ 15,463**	**$ (40,690)**	**$ (728)**	**$ -**	$ 137,573
Net Loss	-	-	-	-	-	(23,155)	-	-	(23,155)
Private placement	6,536	19,825	-	-	-	-	-	-	19,825
Warrants issued in conjunction with private placement	-	-	-	-	4,177	-	-	-	4,177
Share issuance costs	-	(2,234)	-	-	700	-	-	-	(1,534)
Shares issued for exercise of warrants	2,292	5,323	-	-	(2,870)	-	-	-	2,453
Shares issued for exercise of stock options	1,016	3,906	-	-	(2,713)	-	-	-	1,193
Share-based compensation	-	-	-	-	4,332	-	-	-	4,332
Shares issued for services	193	611	-	-	-	-	-	-	611
Share subscriptions received	-	-	51,559	-	-	-	-	-	51,559
Cumulative translation adjustment	-	-	-	-	-	-	(1,457)	-	(1,457)
Balance at December 31, 2022	**108,940**	**$190,959**	**$ 51,559**	**$ -**	**$ 19,089**	**$ (63,845)**	**$ (2,185)**	**$ -**	**$ 195,577**
Balance at January 1, 2023	**108,940**	**$190,959**	**$ 51,559**	**$ -**	**$ 19,089**	**$ (63,845)**	**$ (2,185)**	**$ -**	**$ 195,577**
Net loss	-	-	-	-	-	(25,611)	-	-	(25,611)
Private placement	10,616	20,209	-	-	-	-	-	-	20,209
Warrants issued in conjunction with private placement	-	-	-	-	5,353				5,353
Conversion of subscriptions to shares	23,277	33,300	(33,300)	-	-	-	-	-	-
Warrants issued in conjunction with subscription	-	-	(18,259)		18,259				-
Share issuance costs	-	(7,659)	-	-	1,376	-	-	-	(6,283)
Shares issued for exercise of warrants	6,034	20,346	-	-	(5,378)	-	-	-	14,968
Shares issued for exercise of stock options	576	1,599	-	-	(1,041)	-	-	-	558
Shares issued for ATM	15,691	49,444	-	-	-	-	-	-	49,444

enCore Energy Corp
Consolidated Statements of Stockholders' Equity

Share-based compensation	-	-	-	-	3,464	-	-	-	3,464
Equity portion of convertible promissory note	-	-	-	3,813	-	-	-	-	3,813
Fair value of replacement options for Alta Mesa acquisition	-	-	-	-	81	-	-	-	81
Cumulative translation adjustment	-	-	-	-	-	-	393	-	393
Balance at December 31, 2023	**165,134**	**$308,198**	**$ -**	**$ 3,813**	**$ 41,203**	**$ (89,456)**	**$ (1,792)**	**$ -**	**$ 261,966**
Balance at January 1, 2024	**165,134**	**$308,198**	**$ -**	**$ 3,813**	**$ 41,203**	**$ (89,456)**	**$ (1,792)**	**$ -**	**$ 261,966**
Net loss	-	-	-	-	-	(61,392)	-	(6,601)	(67,993)
Private placement	2,564	10,000	-	-	-	-	-	-	10,000
Contributions from non-controlling interest	-	-	-	-	8,228	-	-	1,759	9,987
Inventory distributions to non-controlling interest	-	-	-	-	-	-	-	(1,905)	(1,905)
Share issuance costs	-	(50)	-	-	-	-	-	-	(50)
Shares issued for exercise of warrants	8,782	33,373	-	-	(7,902)	-	-	-	25,471
Shares issued for exercise of stock options	2,267	3,679	-	-	(1,919)	-	-	-	1,760
Shares issued for ATM	496	2,008	-	-	-	-	-	-	2,008
Share-based compensation	-	-	-	-	4,788	-	-	-	4,788
Conversion of convertible promissory note to shares	6,872	23,117	-	(3,813)	-	-	-	-	19,304
Non-controlling interest Investment in JV Alta Mesa	-	-	-	-	15,458	-	-	39,553	55,011
Cumulative translation adjustment	-	-	-	-	-	-	(1,805)		(1,805)
Balance at December 31, 2024	**186,115**	**$380,325**	**$ -**	**$ -**	**$ 59,856**	**$ (150,848)**	**$ (3,597)**	**$ 32,806**	**$ 318,542**

1. Nature of Operations

enCore Energy Corp. was incorporated on October 30, 2009 under the laws of British Columbia, Canada. enCore Energy Corp., together with its subsidiaries (collectively referred to as the "Company" or "enCore"), is principally engaged in the acquisition, exploration, development and extraction of uranium resource properties in the United States. The Company's corporate headquarters is located at 101 N Shoreline, Suite 450, Corpus Christi, TX 78401.

The Company is focused on the extraction of domestic uranium in the United States. The Company only utilizes the proven In-Situ Recovery technology ("ISR") to provide necessary fuel for the generation of clean, reliable, and carbon-free nuclear energy.

As of December 31, 2024, the Company is an "Exploration Stage Issuer" as defined by S-K 1300 as it has not established proven or probable mineral reserves, as required by the SEC to be defined as a Development Stage Issuer.

2. Summary of Significant Accounting Policies

Basis of Presentation

As a non-U.S. company listed on the NASDAQ, the Company historically met the definition of a foreign private issuer ("FPI") as defined by the United States Securities and Exchange Commission ("SEC"). As such, the Company prepared consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS").

As of January 1, 2025, the Company has become a U.S. Domestic Issuer. Upon becoming a U. S. Domestic Issuer, and including the report herein, the Company has prepared its consolidated financial statements in accordance with United States Generally Accepted Accounting Principles ("U.S. GAAP") effective with the preparation of these financial statements as of and for the year ended December 31, 2024.

For the year ended December 31, 2024, the Company has therefore retrospectively adopted U.S. GAAP. The consolidated financial statements of the Company have been prepared in accordance with U.S. GAAP for all periods presented. Comparative figures, which were previously prepared in accordance with IFRS, have been adjusted as required to be compliant with the Corporation's accounting policies under U.S. GAAP.

These financial statements are presented in thousands of United States dollars. All inter-company transactions and balances have been eliminated upon consolidation.

There are certain disclosures where the Company discloses the amount in Canadian Dollar ("CAD"), as this is the currency in which the instrument is denominated in.

Principles of Consolidation

These financial statements incorporate the financial statements of the Company and its controlled subsidiaries. We consolidate entities that we control due to ownership of a majority voting interest and we consolidate variable interest entities (VIEs) when we are the primary beneficiary. All intercompany transactions and balances have been eliminated.

The Company has a 70% interest in the Alta Mesa project with Boss Energy Limited ("Boss" or "Boss Energy"). The Company retained control after Boss acquired their interest. Alta Mesa is considered a variable interest entity ("VIE"), with the Company being considered the primary beneficiary. As a result, the Company consolidates the operations of Alta Mesa with an offsetting non-controlling interest being recorded. Refer to Note 10 for more information related to the Boss transaction.

Non-controlling interests represent the portion of their equity which is not attributable, directly or indirectly, to the Company. These amounts are required to be reported as equity instead of as a liability on the consolidated balance sheet. Financial Accounting Standards Board (the "FASB") Accounting Standard Codification ("ASC") Topic

810, Consolidation requires net income or loss from non-controlling interests to be shown separately on the consolidated statements of operations.

Segments

Operating segments are defined as components of an entity for which discrete financial information is available and is regularly reviewed by the Chief Operating Decision Maker ("CODM") in making decisions regarding resource allocation and performance assessment. The Company's CODM is its Chief Executive Officer. The Company has one operating segment and one reportable segment. This reportable segment relates to uranium extraction, recovery and sales of uranium from mineral properties along with the exploration, permitting and evaluation of uranium properties in the United States. The CODM assesses financial performance and decides how to allocate resources based on performance of the mineral properties and the sale of Uranium.

Mineral Rights and Properties

We have established the existence of mineralized materials for certain uranium projects, including our Rosita and Alta Mesa Projects (collectively, the "ISR Mines Projects"). We have not established proven or probable reserves, as defined by S-K 1300, through the completion of a "final" or "bankable" feasibility study for any of the uranium projects we operate, including our ISR Mines Projects. Furthermore, we currently have no plans to establish proven or probable reserves for any of our uranium projects for which we plan on utilizing in-situ recovery ("ISR") mining, such as our ISR Mines Projects. As a result, and despite the fact that we commenced extraction of mineralized materials at our ISR Mines Projects, we remain an Exploration Stage company, as defined by the SEC, and will continue to remain as an Exploration Stage company until such time proven or probable reserves have been established.

In accordance with U.S. GAAP, expenditures relating to the acquisition of mineral rights are initially capitalized as incurred while exploration and pre-extraction expenditures are expensed as incurred until such time as we exit the Exploration Stage by establishing proven or probable reserves. Expenditures relating to exploration activities, such as drill programs to establish mineralized materials, are expensed as incurred. Expenditures relating to pre-extraction activities, such as the construction of mine wellfields, ion exchange facilities and disposal wells, are expensed as incurred until such time proven or probable reserves are established for that project, after which expenditures relating to mine development activities for that particular project are capitalized as incurred.

When the Company starts to extract mineral materials at our ISR Mines Projects, the capitalized costs are depleted over estimated mineral resources using the units-of-production method. Depletion costs are included in cost of sales in the consolidated statement of operations.

Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make judgments, estimates and assumptions that affect the reported amount of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported revenues and expenses during the reported periods. Areas requiring significant judgements, estimates and assumptions include the valuation of acquired mineral rights and properties and equity-accounted investments, existence of impairment indicators for the Company's long-lived assets, valuation and measurement of impairment losses on mineral rights and properties, valuation of asset retirement obligations, and valuation of stock options, share purchase warrants and share-based compensation. Other areas requiring estimates include allocations of expenditures to inventories, depletion and amortization of mineral rights and properties and depreciation of property, plant and equipment. Actual results could differ significantly from those estimates and assumptions.

Asset Acquisitions

The Company performs a screen test as required under U.S. GAAP to determine whether a transaction is an asset acquisition under FASB ASC Topic 805, *Business Combination*. If substantially all of the fair value of gross assets acquired is concentrated in a single identifiable asset (or a group of similar identifiable assets), the assets

acquired would not represent a business and we account for the acquisition as an asset acquisition. In addition, when an acquisition does not meet the definition of a business combination as the acquired entity does not have an input and a substantive process that together significantly contribute to the ability to create outputs, we also account for the acquisition as an asset acquisition. In an asset acquisition, any direct acquisition-related transaction costs are capitalized as part of the purchase consideration. Deferred taxes are recorded on temporary book/tax differences in an asset acquisition using the simultaneous equations method and adjusting the assigned value of the non-monetary assets acquired to include the deferred tax liability. There is no goodwill recorded, with any excess purchase price being allocated on a pro-rata basis to the acquired assets based on their relative fair values.

Foreign Currency

These financial statements are presented in U.S. dollars, unless otherwise specified. The functional currency of enCore Energy Corp. is the Canadian dollar. The functional currency of the Company's subsidiaries is the U.S. Dollar based on the currency of the primary economic environment in which these subsidiaries operate.

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the date of the transaction. Foreign currency monetary items are translated at the period-end exchange rate. Non-monetary items measured at historical cost continue to be carried at the exchange rate at the date of the transaction. Non-monetary items measured at fair value are reported at the exchange rate at the date when fair values were determined.

Exchange differences arising on the translation of monetary items or on settlement of monetary items are recognized in profit or loss in the period in which they arise, except where deferred in equity as a qualifying cash flow or net investment hedge. Exchange differences arising on the translation of non-monetary items are recognized in other comprehensive loss in the consolidated statements of comprehensive loss to the extent that gains and losses arising on those non-monetary items are also recognized in other comprehensive loss. When the non-monetary gain or loss is recognized in profit or loss, the exchange component is also recognized in profit or loss.

On consolidation, the parent Company's financial statements are translated into the presentation currency, being the U.S. dollar. Assets and liabilities are translated at the period-end exchange rate. Income and expenses are translated at the average exchange rate for the period in which they arise. Exchange differences are recognized in accumulated comprehensive loss as a separate component within equity.

Cash, Cash Equivalents and Restricted Cash

Cash and cash equivalents consist of bank deposits and term deposits with an original maturity of three months or less. Restricted cash is excluded from cash and cash equivalents and is included in long-term assets. Restricted cash relates to collateralization of its performance obligations with an unrelated third party, also known as performance bonds. These funds are not available for the payment of general corporate obligations. The performance bonds are required for future restoration and reclamation obligations related to the Company's operations. Refer to Note 11 – Asset Retirement Obligations and Restricted Cash.

Inventories

Inventories are uranium concentrates and converted products including chemicals and are measured at the lower of cost and net realizable value. The cost of converted products and uranium concentrates is based on the first in first out (FIFO) method. Cost includes direct materials, direct labor and operational overhead expenses. Net realizable value is the estimated selling price in the ordinary course of business, less the estimated costs of completion and selling expenses. Consumable supplies and spares are valued at the lower of cost or replacement value.

Marketable Securities

Marketable equity securities consist of investments in publicly traded equity securities. The Company classifies and accounts for its marketable equity securities as available-for-sale. Subsequent to initial recognition, marketable equity securities are measured at fair value and changes therein are recognized as a component of other income (loss) in the consolidated statements of operations.

Equity Method Investments

Investments in an entity in which our ownership is greater than 20% but less than 50%, a 50/50 joint venture which the Company does not have control, or an entity where other facts and circumstances indicate that we have the ability to exercise significant influence over its operating and financing policies, are accounted for using the equity method in accordance with FASB ASC Topic 323, *Investments – Equity Method and Joint Ventures*.

The Company accounts for equity method investments over which the Company exerts significant influence, but not control, over the financial and operating policies through the fair value option of FASB ASC Topic 825, *Financial Instruments*. The fair value of the investee's common shares is measured based on its closing market price. Subsequent to initial recognition, equity method investments are measured at fair value and changes therein are recognized as a component of other income (loss) in the consolidated statements of operations.

Property, Plant and Equipment

Property, plant and equipment is measured at cost, less accumulated depreciation. Useful lives are based on the Company's estimate at the date of acquisition and are depreciated straight-line as follows for each class of assets:

Category	Range
Uranium Plant	15-25 years
Other Property Plant and Equipment	3-5 years
Software	2-3 years
Furniture	3-5 years
Buildings	10-40 years

Intangible Assets

Intangible assets consist of a data access agreement and data purchases, which are definite- and indefinite-lived assets, respectively. Definite-lived intangible assets are amortized over 14 years on a straight-line basis.

The Company reviews its definite-lived intangible assets for impairment when impairment indicators exist. When impairment indicators exist, the Company determines if the carrying value of its definite-lived intangible assets or asset groups exceeds the related undiscounted future cash flows. In cases where the carrying value exceeds the undiscounted future cash flows, the carrying value is written down to fair value. Fair value is determined using a discounted cash flow analysis.

The Company assesses its indefinite-lived intangible assets for impairment periodically to determine if any adverse conditions exist that would indicate impairment or when impairment indicators exist. The Company assesses its indefinite-lived intangible assets for impairment at least annually by comparing the fair value of the indefinite-lived intangible assets to their carrying value.

There were no indicators of impairment as of December 31, 2024, 2023 or 2022.

Impairment of Long-lived Assets

The Company reviews and evaluates its long-lived assets for impairment when events or changes in circumstances indicate that the related carrying amounts may not be recoverable. Mineral rights and properties and mining properties are monitored for impairment based on factors such as uranium prices, government regulations, our continued right to explore the area, exploration reports, assays, technical reports, drill results and its continued plans to fund exploration and development programs on the property.

On each reporting date, the Company conducts a review of potential triggering events for all its mineral rights and properties and mining properties. When events or changes in circumstances indicate that the related carrying amounts may not be recoverable, the Company carries out a review and evaluation of its long-lived assets in accordance with its accounting policy. Impairment losses are recognized as part of operating losses in the consolidated statement of operations.

Recoverability is measured by comparing the undiscounted future net cash flows to the net book value. When the net book value exceeds future net undiscounted cash flows, the fair value is compared to the net book value and an impairment loss may be measured and recorded based on the excess of the net book value over fair value. Fair value for mineral rights and properties prior to extraction is based on combined approach of a discounted cash flow analysis and a market approach.

Future cash flows are estimated based on quantities of recoverable mineralized material, expected uranium or Rare Earth Elements ("REE") prices (considering current and historical prices, trends and estimates), production levels, operating costs, capital requirements and reclamation costs, all based on life-of-mine plans. In estimating future cash flows, assets are grouped at the lowest level, for which there are identifiable cash flows that are largely independent of future cash flows from other asset groups. The Company's estimates of future cash flows are based on numerous assumptions, and it is possible that actual future cash flows will be significantly different than the estimates, as actual future quantities of recoverable minerals, uranium prices, production levels, costs and capital are each subject to significant risks and uncertainties.

There were no indicators of impairment for long-lived assets as of December 31, 2024 or 2023 or 2022.

Operating Leases

The Company accounts for office leases under FASB ASC Topic 842, *Leases*, which requires leases to be recognized as assets and liabilities on the balance sheet for the rights and obligations created by all leases with terms of more than 12 months. The Company recognizes in the balance sheet a liability to make lease payments (the lease liability) and the right-of-use asset representing the right to the underlying asset for the lease term. For leases with a term of twelve months or less, the Company has made an accounting policy election by class of underlying asset not to recognize lease assets and lease liabilities. The office leases all meet the definition of an operating lease.

Income Taxes

The Company uses the asset and liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recorded based on differences between the financial statement carrying values of existing assets and liabilities and their respective income tax bases (temporary differences), and losses carried forward. Deferred income tax assets and liabilities are measured using the enacted tax rates which will be in effect when the temporary differences are likely to reverse. The effect on deferred income tax assets and liabilities of a change in tax rates is included in operations in the period in which the change is enacted.

The Company records a valuation allowance to reduce deferred income tax assets to the amount that is believed more likely than not to be realized. When the Company concludes that all or part of the deferred income tax assets are not realizable in the future, the Company makes an adjustment to the valuation allowance that is charged to income tax expense in the period such determination is made.

Asset Retirement Obligations

Various federal and state mining laws and regulations require our Company to reclaim the surface areas and restore underground water quality to the pre-existing quality or class of use after the completion of mining. We recognize the present value of the future restoration and remediation costs as an asset retirement obligation in the period in which we incur an obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development and/or normal use of the assets.

Asset retirement obligations consist of estimated final well closure, plant and equipment decommissioning and removal and environmental remediation costs to be incurred by our Company in the future. The asset retirement obligation is estimated based on the current costs escalated at an inflation rate and discounted at a credit adjusted risk-free rate at inception. The asset retirement obligations are capitalized as part of the costs of the underlying assets and amortized over their remaining useful life. The asset retirement obligations are accreted to an undiscounted value until they are settled. The accretion expenses are charged to earnings and the actual retirement costs are recorded against the asset retirement obligations when incurred.

Share-based Compensation

We measure share-based awards, typically options, at fair value on the date of the grant and expense the awards over the requisite service period of employees, brokers or consultants. The fair value of these stock options is measured at the grant date using the Black-Scholes option pricing model. The share-based awards are equity-classified.

Share-based compensation expense related to awards with only service conditions having a graded vesting schedule is recorded on a straight-line basis over the requisite service period for each separately vesting portion of the award as if the award were, in substance, multiple awards, while expense for all other awards are recognized on a straight-line basis.

The Company's estimates may be impacted by certain variables including, but not limited to, stock price volatility, employee stock option exercise behaviors, additional stock option grants, the Company's performance and related tax impacts.

Warrants

Warrants that are issued with shares issued have the proceeds allocated between the shares and the warrants based on their relative fair value. The fair value of the warrants is measured at the grant date using the Black-Scholes option pricing model. The fair value of the shares granted is based on the respective share's publicly-traded market price.

Warrants issued to brokers are measured at their fair value on the vesting date. The fair value of stock options and warrants issued to brokers are estimated using the Black-Scholes option pricing model.

Financial Instruments

Financial assets and liabilities are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets and liabilities are recognized when the rights to receive or obligation to pay cash flows from the assets or liabilities have expired or been settled or have been transferred and the Company has transferred substantially all risks and rewards of ownership.

The Company classifies its financial instruments in the following categories: at fair value through profit and loss ("FVTPL"), at fair value through other comprehensive loss ("FVTOCI"), or at amortized cost. The Company determines the classification of financial assets at initial recognition. The classification of debt instruments is driven by the Company's business model for managing the financial assets and their contractual cash flow

characteristics. Equity instruments that are held for trading are classified as FVTPL. For other equity instruments, on the day of acquisition the Company can make an irrevocable election (on an instrument-by instrument basis) to designate them at FVTOCI. Financial liabilities are measured at amortized cost, unless they are required to be measured at FVTPL (such as instruments held for trading or derivatives) or the Company has opted to measure them at FVTPL. Financial assets and liabilities carried at FVTPL are initially recorded at fair value and transaction costs are expensed in profit or loss. Realized and unrealized gains and losses arising from changes in the fair value of the financial assets and liabilities held at FVTPL are included in the consolidated statements of loss in the period in which they arise.

Revenue Recognition and Trade Receivables

Our revenues are primarily derived from the sale of uranium that we either purchased from a third-party or recovered and extracted from the Company's mining properties.
The Company's sales of uranium are derived from contracts with major U.S utility companies. Revenue is recognized when delivery is evidenced by book transfer at the conversion facility. The sales contracts specify the quantity to be delivered, the price, payment terms and the year of the delivery. There is no variable consideration. Under these contracts, each delivery product transferred to the customer represents a separate performance obligation; therefore, future quantities are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required. Under the Company's uranium contracts, it invoices customers after the performance obligations have been satisfied, at which point the Company has an enforceable right to payment. Accordingly, the Company's uranium contracts do not give rise to contract assets or liabilities.

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The Company evaluates its estimate of expected credit losses based on historical experience and current and forecasted future economic conditions for each portfolio of customers. As of December 31, 2024 and 2023, the Company did not have an allowance for expected credit losses for trade accounts receivable. As of December 31, 2024 and 2023, the Company did not have receivables from contracts with customers.

Earnings/(loss) per Share

Basic earnings or loss per share includes no potential dilution and is computed by dividing the earnings or loss attributable to common stockholders by the weighted-average number of common shares outstanding for the period. Diluted earnings or loss per share reflects the potential dilution of securities that could share in the earnings or loss of our Company. Dilutive securities are excluded from the calculation of our diluted weighted average common shares outstanding if their effect would be anti-dilutive based on the treasury stock method or due to a net loss from continuing operations.

Non-controlling Interests

Non-controlling interests are measured at their proportionate share of the acquiree's identifiable net assets at the acquisition date and are adjusted at each reporting date for the net income (loss) attributable to that non-controlling interest during that period. The difference between the cash received and the proportionate share of the acquiree's identifiable net assets is attributed to additional paid-in-capital.

Recently Issued Accounting Standards

Recently Adopted Accounting Standards

In November 2023, the FASB issued ASU 2023-07, Segment Reporting (Topic 280)-Improvements to Reportable Segment Disclosures. The ASU enhances disclosure of significant segment expenses by requiring disclosure of significant segment expenses regularly provided to the chief operating decision maker, extend certain annual disclosures to interim periods, and permits more than one measure of segment profit or loss to be reported under

certain conditions. The amendments are effective for the Company in years beginning after December 15, 2023, and interim periods within years beginning after December 15, 2024. Early adoption of the ASU is permitted, including adoption in any interim period for which financial statements have not been issued. The Company adopted this effective January 1, 2024. The Company expanded its segment disclosure.

Recently Issued Accounting Standards Not Yet Adopted

In December 2023, the FASB issued ASU 2023-09, Income Taxes (Topic 740)-Improvements to Income Tax Disclosures. The ASU requires additional quantitative and qualitative income tax disclosures to allow readers of the consolidated financial statements to assess how the Company's operations, related tax risks and tax planning affect its tax rate and prospects for future cash flows. For public business entities, the ASU is effective for annual periods beginning after December 15, 2024. The Company is currently evaluating the impact of adopting this ASU on its consolidated financial statements and disclosures but does not expect that it will have a material impact on the Company. The Company will elect to adopt this prospectively when adopted.

On March 21, 2024, the FASB issued ASU 2024-01, Compensation—Stock Compensation (Topic 718): Scope Application of Profits Interest and Similar Awards, which clarifies how an entity determines whether a profits interest or similar award (hereafter a "profits interest award") is (1) within the scope of ASC 718 or (2) not a share-based payment arrangement and therefore within the scope of other guidance. This ASU will be effective for annual periods beginning after December 15, 2024, and interim periods within those annual periods. The Company anticipates that it will not have a material impact on the Company.

In March 2024, the FASB issued ASU 2024-02, Codification Improvements - Amendments to Remove References to the Concepts Statements. This ASU contains amendments to the Codification that removes references to various FASB Concepts Statements. The effort facilitates Codification updates for technical corrections such as conforming amendments, clarifications to guidance, simplifications to wording or the structure of guidance and other minor improvements. While the amendments are not expected to result in significant changes for most entities, the FASB provided transition guidance since some entities could be affected. This ASU will be effective for fiscal years beginning after December 15, 2024, with early adoption permitted. The Company is currently evaluating the impact of adopting this ASU on its consolidated financial statements and disclosures.

In November 2024, the FASB issued ASU No. 2024-04, Debt—Debt with Conversion and Other Options (Subtopic 470-20) – Induced Conversions of Convertible Debt Instruments, or ASU 2024-04. The guidance in ASU 2024-04 clarifies the requirements related to accounting for the settlement of a debt instrument as an induced conversion when changes are made to conversion features as part of an offer to settle the instrument. This ASU is effective for annual periods beginning after December 15, 2025, with early adoption permitted. The amendments may be applied either (1) prospectively to any settlements of convertible debt instruments that occur after the effective date of this ASU or (2) retrospectively to all prior periods presented in the financial statements, with a cumulative adjustment-effect adjustment to equity. This will not have an impact on the Company.

3. Conversion from IFRS to U.S. GAAP

As part of the U.S. Domestication, the Company has retrospectively converted its Consolidated Financial Statements from IFRS to U.S. GAAP. Refer to Note 1 for additional details. The significant differences between IFRS and U.S. GAAP as they relate to these financial statements are as follows:

{a} Exploration and Development Costs

Under IFRS, the Company capitalized exploration and development costs related to the Company's Mineral Properties. Under US GAAP, the Company is only eligible to capitalize costs related to the following for Mineral Properties:

- Asset Acquisitions
- Direct Development Costs after establishing proven/probable reserves. This requires obtaining a S-K 1300 that supports the existence of probable or proven mineral reserves. As of December 31, 2024, the Company's S-K 1300s do not indicate proven/probable reserves. Therefore, the Company remains an Exploration Stage Issuer and is unable to capitalize development costs.

Exploration costs, land lease costs and development costs are expensed as incurred for the years ended December 31, 2024, 2023 and 2022.

{b} Income Taxes

The Company recorded a deferred tax liability under U.S GAAP as a result of the Azarga asset acquisition. Under U.S GAAP, this requires book basis increase for the change in fair value. However, there is no tax basis bump related to the Azarga asset acquisition. This results in a difference that requires a deferred tax liability under U.S. GAAP ASC 740, Income Taxes. Under IFRS, this does not result in a deferred tax liability.

{c} Share-based Compensation

Under IFRS, the Company utilized the expected term for share-based compensation in the Black-Scholes valuation calculation. The Company under U.S. GAAP elected the simplified method for 'vanilla' stock options, as permitted by the SEC. This allows the average between the vesting period and the contractual period to be utilized for the expected term.

{d} Investments in Uranium

Under IFRS, the Company treated its purchases of uranium as investment property. Under IFRS, the Company adjusted its inventory to the fair market value as of each reporting period and upon sale, recorded the sale as a non-operating gain. Under U.S. GAAP, the Company treated its purchases of Uranium as inventory, which is held at the lower of carrying value and net realizable value. This resulted in reclassification of the income statement impacts to revenue and cost of goods sold and the deferral of gain/loss on the changes in the fair market value of uranium until the uranium was sold to customers.

This impacted the consolidated statements of cash flows for the years ended December 31, 2023 and 2022, as the impacts from the decrease in the investment in uranium and the proceeds received from the sale were included as investing activity. For the year ended December 31, 2023, this would result in an increase in cash from operating activities of $5,576 and a decrease in cash from investing activities of $5,576. For the year ended December 31, 2022, this would result in an increase in cash from operating activities of $4,245 and a decrease in cash from investing activities of $4,245.

{e} Warrants granted in Conjunction with Equity Financing

Under IFRS, the Company allocated the proceeds received from warrants granted in conjunction with equity financing to common stock. Under U.S. GAAP, the proceeds received are required to be applied to

the warrants and the share issuance based on their relative fair value. This results in a higher additional paid in capital balance upon the granting of the warrants than under IFRS and a lower amount attributed to common stock than under IFRS.

The significant differences in the Consolidated Statements of Operations were as follows which show the (increase)/decrease to net loss during the period;

		Years Ended December 31,		
	Note	**2024**	**2023**	**2022**
Net loss - IFRS		$ (58,787)	$ (20,175)	$ (16,615)
Revenue	{d}	-	22,148	4,245
Cost of goods sold	{a},{d}	2,584	(19,573)	(2,656)
Mineral property expenditures	{a}	(19,576)	(11,075)	(9,897)
General and administrative	{c}	1,666	1,721	1,322
Depreciation, amortization and accretion		191	167	89
Impairment of mineral properties	{a}	-	1,538	-
Gain on sale of uranium	{d}	-	(2,575)	(35)
Gain on sale of mineral properties	{a}	-	1,746	227
Provision for income taxes	{b}	5,929	467	165
Net loss - U.S. GAAP		$ (67,993)	$ (25,611)	$ (23,155)

The significant differences in the Consolidated Balance Sheet are as follows;

		December 31, 2024		
	Note	**IFRS**	**Adjustments**	**U.S. GAAP**
Assets				
Inventory	{a}	$ 21,315	$ (348)	$ 20,967
Mineral rights and properties, net	{a}	286,587	(14,665)	271,922
Right of use assets - operating lease		293	17	310
Total assets		407,718	(14,996)	392,722
Liabilities				
Accounts payable and accrued liabilities	{a}	7,421	43	7,464
Deferred tax liability	{b}	-	26,980	26,980
Total liabilities		47,157	27,023	74,180
Equity				
Common stock	{e}	397,622	(17,297)	380,325
Additional paid in capital	{c}	52,431	7,425	59,856
Accumulated deficit	{a},{b},{c}	(118,702)	(32,146)	(150,848)
Total equity		$ 360,560	$ (42,018)	$ 318,542

enCore Energy Corp.
Notes to Consolidated Financial Statements
(all amounts in thousands, except for shares)

	Note	December 31, 2023 IFRS	Adjustments	U.S. GAAP
Assets				
Mineral rights and properties, net	{a}	$ 272,511	$ 1,979	$ 274,490
Right of use assets - operating lease		444	15	459
Total assets		324,573	1,994	326,567
Liabilities				
Accounts payable and accrued liabilities	{a}	3,579	3	3,582
Deferred tax liability	{b}	-	27,959	27,959
Total liabilities		36,639	27,962	64,601
Equity				
Common stock	{e}	333,122	(24,924)	308,198
Additional paid in capital	{c}	19,308	21,895	41,203
Accumulated deficit	{a},{b},{c}	(66,516)	(22,940)	(89,456)
Total equity		$ 287,935	$ (25,969)	$ 261,966

4. Asset Acquisitions and Sales

Acquisitions

In November 2022, the Company, and Energy Fuels, Inc ("Energy Fuels") entered into a Definitive Agreement. Pursuant to the terms and subject to the conditions in the Definitive Agreement, on February 14, 2023, the Company acquired the Alta Mesa in-Situ Recovery uranium project ("Alta Mesa").

The aggregate amount of the total consideration was $121,384 which consisted of a cash payment of $60,000, the issuance of a $60,000 secured vendor takeback convertible promissory note and 44,681 enCore stock options (the "Replacement Options") for options held by Energy Fuels option holders, valued at $81 using the Black-Scholes option pricing model, and total transaction costs of $1,303 associated with the Arrangement. The transaction did not qualify as a business combination as defined in FASB ASC Topic 805, Business Combinations. It has been accounted for as an asset acquisition with the purchase price allocated based on the estimated fair value of the assets and liabilities summarized as follows:

Consideration		**Amount**
Cash	$	60,000
Convertible promissory note		60,000
Fair value of replacement options		81
Transaction costs		1,303
Total consideration value	**$**	**121,384**

Net assets acquired		**Amount**
Prepaid	$	42
Property, plant, and equipment		6,111
Mineral properties		121,006
Asset retirement obligations		(5,489)
Accounts payable and accrued liabilities		(286)
Total net assets acquired	**$**	**121,384**

The fair value of the Replacement Options is based on the issuance of 44,681 options with a fair value of $81.

Sales

On July 20, 2023, the Company divested its subsidiary Neutron Energy, Inc, including its holding of the Marquez-Juan Tafoya Uranium Project to Anfield Energy, Inc. Pursuant to a Share Purchase Agreement, the Company received cash consideration of $3,796 and 185,000,000 shares of Anfield with a fair value of $7,023 (Note 6). The net book value of the subsidiary was $2,433 at the transaction date, transaction costs of $423 were incurred and $33 in currency exchange effect was recognized resulting in a gain on divestment of subsidiary of $7,995, which is included in gain on sale of mineral properties on the Company's consolidated statements of operations.

5. Inventory

As of December 31, 2024, the Company held 245,000 pounds of purchased uranium, 59,395 pounds of extracted uranium inventory and 37,775 pounds of raw uranium. As of December 31, 2023, the Company did not hold any uranium inventory.

Costs of inventory consisted of the following:

	As of December 31,	
	2024	2023
Purchased uranium inventories	$ 16,614	$ -
Raw uranium	1,564	-
Uranium concentrates from extraction	2,718	-
Materials and supplies	71	9
Total	$ 20,967	$ 9

As of December 31, 2024, in order to measure inventory at the lower of cost and net realizable value, the Company recognized impairment losses of $6,054 related to purchased uranium. These losses are recorded in cost of goods sold in the Company's consolidated statements of operations.

6. Investments in Equity and Marketable Securities

The Company records both marketable securities and equity method investments at fair value. The Company has classified these investments on the Company's consolidated balance sheets as marketable securities.

The following table summarizes the fair value of the Company's investment in equity securities as of December 31, 2024 and 2023:

	As of December 31,	
	2024	2023
Balance, beginning of year	$ 19,933	$ 3,947
Investment in publicly traded companies	9,798	9,815
Divestment of publicly traded companies	(548)	-
Fair value gain/(loss) on marketable securities	(2,711)	5,918
Foreign exchange translation	(1,589)	253
Balance, end of year	24,883	19,933
Noncurrent marketable securities	(837)	(3,047)
Current marketable securities	$ 24,046	$ 16,886

During the year ended December 31, 2024, the company purchased an additional 15,158,426 shares and 3,690,372 warrants to purchase common stock of an investment and disposed of 26,308,250 shares related to investments held as of December 31, 2023. As of December 31, 2024, the remaining shares and warrants are carried at a fair value of $24,883. These companies are publicly traded.

During the year ended December 31, 2023, the Company purchased a total of 194,247,800 shares in companies that are publicly traded. As of December 31, 2023, these shares are carried at a fair value of $19,933.

The realized gain on marketable securities sold during the year ended December 31, 2024, was $248. There were no realized gains or losses during the year ended December 31, 2023. The unrealized loss on marketable securities for the year ended December 31, 2024 was $2,711 (year ended December 31, 2023 – $5,918 unrealized gain). These net realized and unrealized gains and losses are recorded in the Consolidated Statements of Operations.

7. Intangible assets

Intangible assets consist of the following as of December 31, 2024 and 2023.

	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
December 31, 2024			
Definite-lived: Data access agreement	$ 250	$ 107	$ 143
Indefinite-lived: Data purchases	328	-	328
	$ 578	$ 107	$ 471
December 31, 2023			
Definite-lived: Data access agreement	$ 272	$ 97	$ 175
Indefinite-lived: Data purchases	339	-	339
	$ 611	$ 97	$ 514

Aggregate intangible asset amortization expense was $19 for the years ended December 31, 2024, 2023 and 2022 and was recorded in depreciation, amortization and accretion expense in the consolidated statements of operations.

Estimated future intangible asset amortization expense based upon the carrying value as of December 31, 2024 is as follows (in thousands):

	2025	2026	2027	2028	2029	Thereafter
Amortization expense	$ 19	$ 19	$ 19	$ 19	$ 19	$ 48

8. Property, Plant & Equipment, Net

Property, plant and equipment consists of the following:

	As of December 31,	
(In thousands)	2024	2023
Uranium plants	$ 8,292	$ 4,202
Furniture	135	124
Buildings	807	401
Software	142	142
Other property and equipment	8,882	6,894
Construction in progress	10,039	5,374
Total property, plant and equipment	28,297	17,137
Less: Accumulated depreciation	(4,280)	(2,167)
Total property, plant and equipment, net	$ 24,017	$ 14,970

Aggregate depreciation expense was $2,113, $1,494 and $269 for the years ended December 31, 2024, 2023 and 2022, respectively and is included in depreciation, amortization and accretion in the consolidated statements of operations.

9. Mineral Rights and Properties

As of December 31, 2024, we had mineral rights in the US states of Texas, Wyoming, South Dakota, Colorado, Arizona and New Mexico. These mineral rights were acquired through asset acquisitions, lease or option agreements. As of December 31, 2024, annual maintenance payments of approximately $516 are required to maintain these mineral rights.

As of December 31, 2024 and 2023, the activity of these mineral rights and properties was as follows:

	Amount
Balance, December 31, 2022	$ 154,765
Additions	122,894
Divestiture	(3,169)
Balance, December 31, 2023	274,490
Depletion	(2,568)
Balance, December 31, 2024	$ 271,922

The Company recognized depletion of $2,568 during the year ended December 31, 2024, $1,334 of which was included as part of cost of sales and $1,234 that was capitalized into ending inventory.

Texas

Alta Mesa Project

The Alta Mesa Project is located in Brooks County, Texas.

In February 2024, the Company completed several transactions under a master transaction agreement with Boss Energy Ltd. The completion of this transaction resulted in the Company holding a 70% interest in the project while also remaining as the project manager. Boss Energy Ltd. holds a 30% interest in the project. Refer to Note 10 for further details. As of December 31, 2024, $118,438 was capitalized as a Mineral Rights and Property on the Company's consolidated balance sheet.

Wyoming

Gas Hills

The Gas Hills Project is located in Riverton, Wyoming. This project is still in the exploration phase.

Juniper Ridge

The Juniper Ridge Project is located in the southwest portion of Wyoming.

South Dakota

Dewey Burdock

The Dewey Burdock Project is an in-situ recovery uranium project located near Edgemont, South Dakota.

Notably, the advanced stage Dewey Burdock Uranium Project (Dewey-Burdock) in South Dakota has demonstrated ISR resources, including a 2019 Preliminary Economic Assessment (PEA) citing robust economics. The Company is in the process of reviewing and updating the PEA to reflect current economics and planning. The project has its source material license from the US Nuclear Regulatory Commission (NRC) and its underground injection permits and aquifer exemption from the US Environmental Protection Agency (EPA).

New Mexico

McKinley, Crownpoint and Hosta Butte

The Company owns a 100% interest in the McKinley properties and a 60 - 100% interest in the adjacent Crownpoint and Hosta Butte properties, all of which are located in McKinley County, New Mexico. The Company holds a 60% interest in a portion of a certain section at Crownpoint. The Company owns a 100% interest in the rest of the Crownpoint and Hosta Butte project area, subject to a 3% gross profit royalty on uranium produced.

10. Sale of Minority Interest in Alta Mesa

On December 5, 2023, the Company entered into a Master Transaction Agreement (the "MT Agreement") with Boss, a public company domiciled in Australia. Pursuant to the MT Agreement, Boss Energy was assigned the right to acquire a 30% interest in the Alta Mesa assets. On February 26, 2024, pursuant to the terms of a MT Agreement, Boss Energy acquired a 30% equity interest in a new limited liability company (the "Alta Mesa Holdco") that was formed to hold the Alta Mesa project, in exchange for a payment of $60,000. The Company holds 70% equity in Alta Mesa Holdco. Upon closing of the Transaction, the parties entered into an agreement which governs Alta Mesa Holdco. Pursuant to the agreement, the Company acts as manager of the Alta Mesa Holdco and is entitled to a management fee.

Boss also acquired 2,564,102 common shares of the Company for total proceeds to the Company of $10,000. Finally, the parties also entered into a strategic collaboration agreement for the collaboration and research to develop the Company's prompt fission neutron technology, to be financed equally by each party. The terms of the agreement and the disposal of a 30% interest in the Alta Mesa Holdco support that control was retained both before and after Boss acquired their interest, and that joint control is not present. As such, Company will continue to consolidate the operations of Alta Mesa Holdco with non-controlling interest being recorded.

The table below is a summary of the accounting for recognition of the initial Non-Controlling Interest on Boss acquiring 30% interest in the Alta Mesa Holdco. The difference between the percent of the net assets attributable to Boss and the consideration received is included as part of additional paid in capital.

		Amount
Boss Initial Non-Controlling interest		
Cash received	$	60,000
Additional paid in capital		(20,447)
Non-controlling interest	$	39,553

The Company, upon initial recognition and formation of the joint venture and the sale of minority interest to Boss, recognized a decrease in additional paid-in capital and an increase in income tax benefit of $4,989 due to there being a difference between the selling price of the minority interest and the book basis of the non-controlling interest as of the formation date.

The table below is a summary of the accounting for Non-Controlling Interest as of December 31, 2024.

		Amount
Initial non-controlling interest	$	39,553
Net loss for the period attributable to non-controlling interest		(6,601)
Inventory distributions to non-controlling interest		(1,905)
Contributions from non-controlling interest		1,759
Non-controlling interest	$	32,806

11. Asset Retirement Obligations and Restricted Cash

The asset retirement obligations continuity summary is as follows:

		Amount
Balance, December 31, 2022	$	4,752
Additions		5,489
Accretion		1,099
Settlement		(291)
Change in estimates		(221)
Balance, December 31, 2023	$	10,828
Accretion		1,065
Settlement		(399)
Change in estimates		5,424
Balance, December 31, 2024	$	16,918

The Company expensed the change in estimate for the years ended December 31, 2024 and 2023 as a result of these being adjustments to the estimate for asset retirement obligations that were acquired as part of asset acquisitions.

As of December 31, 2024 and 2023, the undiscounted cash flows total $23,529 and $17,130, respectively.

As of December 31, 2024 and 2023, the Company deposited $7,751 and $7,680, respectively, for collateralization of its performance obligations with an unrelated third party also known as performance bonds. These funds are not available for the payment of general corporate obligations. The performance bonds are required for future restoration and reclamation obligations related to the Company's operations. These funds are categorized as restricted cash on the Company's consolidated balance sheet.

12. Commitments and Contingencies

General Legal Matters

Other than routine litigation incidental to our business, or as described below, the Company is not currently a party to any material pending legal proceedings that management believes would be likely to have a material adverse effect on our financial position, results of operations or cash flows.

Mineral Property Commitments

The Company enters into commitments with federal and state agencies and private individuals to lease mineral rights. These leases are renewable annually, and annual renewal costs are expected to total $1,505 for the year ended December 31, 2025.

Sales Contracts

The Company has entered into several contracts with traders and nuclear utilities to sell pounds of Uranium through 2033. These contracts have pricing that is based on the spot price of uranium while also incorporating minimum floor and maximum ceiling prices, which are adjusted annually for inflation. The Company's sales commitments in pounds are shown below.

Year	Volume (in pounds)
2025	680,000
2026	825,000
2027	850,000
2028	800,000
2029	1,300,000
Thereafter	2,500,000
Total	6,955,000

Reclamation Bonds

The Company has indemnified third-party companies to provide reclamation bonds as collateral for the Company's AROs. The Company is obligated to replace this collateral in the event of a default and is obligated to repay any reclamation or closure costs due. As of December 31, 2024, the Company has $7,751 posted as collateral against an undiscounted ARO of $23,529. As of December 31, 2023, the Company has $7,680 posted as collateral against an undiscounted ARO of $17,130.

13. Fair Value

Fair value accounting establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements).

The three levels of the fair value hierarchy are described below:

- Level 1 - Unadjusted quoted prices in active markets that are accessible at the measurement date for identical unrestricted assets or liabilities;
- Level 2 - Quoted prices in markets that are not active, quoted prices for similar assets or liabilities in active markets, quoted prices or inputs that are observable, either directly or indirectly, for substantially the full term of the asset or liability, and model-based valuation techniques for which all significant inputs are observable in the market or can be corroborated by observable market data for substantially the full term of the assets or liabilities; and
- Level 3 - Prices or valuation techniques that require inputs that are both significant to the fair value measurement and unobservable (supported by little or no market activity).

The financial instruments, including cash and cash equivalents, accounts and other receivables, restricted cash, accounts payable and accrued liabilities, are carried at cost, which approximates their fair values due to the immediate or short-term maturity.

The Company's investments in equity securities are publicly traded stocks measured at fair value and classified within Level 1 in the fair value hierarchy. Level 1 equity securities use quoted prices for identical assets in active markets.

The Company's investments include certain investments accounted for at fair value consisting of warrants are valued using the Black-Scholes option model based on observable inputs and as such are classified within Level 2 of the hierarchy. The warrant asset is included in marketable securities, long-term on the consolidated balance sheet.

The Company's convertible promissory note debt component was fair valued utilizing a 12% discount rate, which is the Company's estimate of the market discount rate for this arrangement. This is classified within Level 2 of the hierarchy.

	Level 1	Level 2	Level 3	Total
December 31, 2024				
Marketable securities, current and non-current	$ 24,314	$ -	$ -	$ 24,314
Warrant asset	-	569	-	569
	$ 24,314	$ 569	$ -	$ 24,883

	Level 1	Level 2	Level 3	Total
December 31, 2023				
Marketable securities, current and non-current	$ 19,933	$ -	$ -	$ 19,933
Convertible promissory note - debt	-	19,239	-	19,239
	$ 19,933	$ 19,239	$ -	$ 39,172

14. Stockholders' Equity

The authorized common stock the Company consists of an unlimited number of common and preferred shares without par value. The Company's common stock has no par value. All proceeds received for issuance of common stock is attributed to common stock on the Company's consolidated balance sheets.

During the year ended December 31, 2024, the Company issued:

i) 2,564,102 units to Boss in February of 2024. for a private placement at a price of $3.90 per unit for gross proceeds of $10,000.

ii) 6,872,143 common shares were issued to extinguish the convertible note with a carrying value of $23,117 in February 2024.

iii) 8,781,985 common shares were issued on the exercise of warrants, for gross proceeds of $25,471. In connection with the warrants exercised, the Company reclassified $7,902 from additional paid in capital to share capital.

iv) 2,267,155 common shares were issued on the exercise of stock options, for gross proceeds of $1,760. In connection with the stock options exercised, the Company reclassified $1,919 from additional paid in capital to common stock.

v) For the year ended December 31, 2024, 495,765 common shares were sold in accordance with the Company's ATM program for gross proceeds of $2,008.

During the year ended December 31, 2023, the Company issued:

vi) In June 2023 the Company filed a Canadian short form base shelf prospectus of $140,000 and U.S. registration statement on Form F-10. The Company also filed a prospectus supplement, pursuant to which the Company may, at its discretion and from time to time, sell common shares of the Company for aggregate gross proceeds of up to $70,000. The sale of common shares was to be made through "at-the-market distributions" ("ATM"), as defined in the Canadian Securities Administrators' National Instrument 44-102 Shelf Distributions, directly on a U.S. Exchange.

vii) 10,615,650 units for a public offering for gross proceeds of $25,562. Each unit consisted of one common share and one-half share purchase warrant. Each whole warrant entitles the holder to purchase one additional share at a fixed price for a period of three years. The Company allocated the proceeds based on the relative fair value of the common share and the one-half share purchase warrant. The relative fair value of the common share and the purchase warrant was $20,209 and $5,353 respectively.

The Company paid commissions of $1,504 and other cash issuance costs of $392.

viii) 23,277,000 subscription receipts were converted into units for gross proceeds of $51,559. Each unit is comprised of one common share of enCore and one share purchase warrant. Each warrant entitles the holder to purchase one additional share for a period of three years for a fixed price. The Company allocated the proceeds based on the relative fair value of the common share and the one-half share purchase warrant. The relative fair value of the common share and the purchase warrant was $33,300, and $18,259 respectively.

The Company paid commissions of $3,019, other cash issuance costs of $171 and issued 1,350,000 finders' warrants with a fair value of $1,415. 1,066,500 of the finder's warrants are exercisable into one common share of the Company at a fixed price for 27 months from closing; 283,500 of the finder's warrants are exercisable into one common share of the Company at a fixed price for 27 months from closing. The value of the finders' warrants was derived using the Black-Scholes option pricing model.

The weighted average assumptions used in the Black-Scholes option pricing model are as follows ($ amounts in CAD):

Weighted Average				
Quantity		1,066,500		283,500
Exercise Price	$	3.91	$	3.25
Share Price	$	3.20	$	3.20
Discount Rate		4.19 %		4.19 %
Expected life (years)		2.25		2.25
Volatility		81.81 %		81.81 %
Fair value of finders' warrants (CAD per option)	$	1.38	$	1.54

ix) 6,034,478 common shares were issued on the exercise of warrants, for gross proceeds of $14,968. In connection with certain of the warrants exercised, the Company reclassified $5,378 from additional paid in capital to common stock.

x) 576,000 common shares were issued on the exercise of stock options, for gross proceeds of $558. In connection with the stock options exercised, the Company reclassified $1,041 from additional paid in capital to common stock.

xi) In June 2023 the Company filed a Canadian short form base shelf prospectus of $140,000 and U.S. registration statement on Form F-10. The Company also filed a prospectus supplement, pursuant to which the Company may, at its discretion and from time to time, sell common shares of the Company for aggregate gross proceeds of up to $70,000. The sale of common shares is to be made through "at-the-market distributions" ("ATM"), as defined in the Canadian Securities Administrators' National Instrument 44-102 Shelf Distributions, directly on a U.S. Exchange.

For the year ended December 31, 2023, 15,690,943 common shares were sold in accordance with the Company's ATM program for gross proceeds of $49,444.

During the year ended December 31, 2022, the Company issued:

xii) 6,535,947 units through a "bought deal" prospectus offering at a price of CAD $4.59 per unit, for gross proceeds of CAD $30,000 ($24,002). Each unit consisted of one common share and one-half share purchase warrant. Each whole warrant entitles the holder to purchase one additional share at a price of CAD $6.00 for a period of two years. The Company allocated the proceeds based on the relative fair value of the common share and the one-half share purchase warrant. The relative fair value of the common share and the purchase warrant was $19,825, and $4,177, respectively.

The Company paid commissions of CAD $1,613 ($1,239), other cash issuance costs of CAD $305 ($235) and issued 351,307 finders' warrants with a fair value of CAD $875 ($672). The finder's warrants are exercisable into one common share of the Company at a price of CAD $4.59 for two years from closing.

xiii) 2,291,642 common shares were issued on the exercise of warrants, for gross proceeds of $2,453. In connection with certain of the warrants exercised, the Company reclassified $2,870 from additional paid in capital and credited common stock.

xiv) 1,016,436 common shares were issued on the exercised of stock options, for gross proceeds of $1,193. In connection with the stock options exercised, the Company reclassified $2,713 from contributed surplus and credited share capital; and

xv) 193,348 common shares for the settlement and compensation for services received in relation to the Company's acquisition of Azarga Uranium Corporation during the year ended December 31, 2021.

Share Purchase Warrants

A summary of the status of the Company's warrants as of December 31, 2024, December 31, 2023 and December 31, 2022 and changes during the year then ended is as follows:

	Number of Warrants	Weighted Average Exercise Price CAD $
Outstanding, December 31, 2021	**6,298,840**	**2.44**
Granted	3,670,919	5.81
Exercised	(2,291,642)	1.39
Expired	(183,611)	1.67
Outstanding, December 31, 2022	**7,494,506**	**4.43**
Granted	30,013,783	3.80
Exercised	(6,034,479)	3.35
Expired	(12,006)	2.02
Outstanding, December 31, 2023	**31,461,804**	**4.04**
Granted	500	3.90
Exercised	(8,781,985)	3.97
Expired	(2,746,235)	5.95
Outstanding, December 31, 2024	**19,934,084**	**3.81**

As of December 31, 2024, share purchase warrants outstanding were as follows:

	Warrants Outstanding December 31, 2024		
Warrant Price Per Share CAD $	Number of Warrants	Weighted Average Remaining Life (years)	Weighted Average Exercise Price CAD $
3.25	2,369	0.00	3.25
3.91	75	0.00	3.91
4.05	3,835,440	0.21	4.05
3.75	16,096,200	0.91	3.75
Total	19,934,084	1.12	3.81

The fair value of all share purchase warrants granted in conjunction with equity financing is estimated on the grant date using the Black-Scholes option pricing model. The assumptions used in calculating the fair values are as follows:

	02/14/23		02/08/23		03/25/22	
Exercise price	C$3.75		C$4.05		C$6.00	
Share price	C$3.20		C$3.19		C$4.77	
Risk-free rate	3.87	%	3.61	%	2.34	%
Expected life (in years)	3.00		3.00		2.00	
Expected volatility	88.55	%	88.69	%	88.76	%
Expected dividend yield	0	%	0	%	0	%
Grant date fair value	C$1.75		C$1.69		C$2.01	
Grant date fair value after residual fair value allocation	C$1.06		C$1.36		C$1.60	

The Company allocated the proceeds based on above and the fair value of the common stock granted, which was readily determinable.

15. Share-based Compensation and Warrants

Share-based Compensation

The Company adopted a Stock Option Plan (the "Existing Plan") under which it was authorized to grant options to Officers, Directors, employees and consultants enabling them to acquire common shares of the Company. The number of shares reserved for issuance under the Existing Plan cannot exceed 10% of the outstanding common shares at the time of the grant. The options can be granted for a maximum of five years and vest as determined by the Board of Directors.

In August 2024 the Company adopted a new 2024 Long Term Incentive Plan (the "LTIP") to replace the Existing Plan. Awards previously issued and outstanding pursuant to the Existing Plan will continue to be governed by the Existing Plan.

The number of Common Shares reserved for issuance pursuant to Awards granted under the LTIP will not, in the aggregate, exceed 10% of the issued and outstanding Common Shares at the time of the grant. No Award, other than an Option, may vest before the date that is one year following the date on which the Award is granted, except in the case of accelerated vesting as defined in the LTIP.

A continuity schedule of outstanding stock options as of December 31, 2024, and the changes during the fiscal year periods, is as follows:

	Number of stock options	Weighted average exercise price (CAD)
Balance, December 31, 2021	5,272,294	1.42
Granted	3,107,501	4.10
Exercised	(1,016,436)	1.51
Forfeited/expired	(127,711)	3.60
Balance, December 31, 2022	**7,235,648**	**2.52**
Exercisable, December 31, 2022	**4,928,144**	**1.78**
Granted	2,670,181	2.85
Exercised	(575,676)	1.31
Forfeited/expired	(917,271)	3.20
Balance, December 31, 2023	**8,412,882**	**2.63**
Exercisable, December 31, 2023	**5,921,267**	**2.39**
Granted	3,029,000	5.74
Exercised	(2,267,155)	1.06
Forfeited/expired	(300,001)	4.42
Balance, December 31, 2024	**8,874,726**	**4.03**
Exercisable, December 31, 2024	**6,169,340**	**3.55**

As of December 31, 2024, stock options outstanding and exercisable were as follows:

	Options Outstanding December 31, 2024			Options Exercisable December 31, 2024	
Option price per share	**Options #**	**Weighted average remaining life (years)**	**Weighted average exercise price (CAD)**	**Options #**	**Weighted average exercise price (CAD)**
$0.18 - 1.92	860,499	0.05	$1.05	860,499	$1.05
$2.40 - 2.40	2,628,351	0.94	$2.92	2,096,340	$2.95
$4.20 - 5.76	5,385,876	2.01	$5.05	3,212,501	$4.62
	8,874,726	3.01	$4.03	6,169,340	$3.55

As of December 31, 2024, the aggregate intrinsic value of all outstanding stock options granted was estimated at $6,863 (vested: $6,098 and unvested: $765). As of December 31, 2024, the unrecognized compensation cost related to unvested stock options was $2,675, which is expected to be recognized over a weighted average period of 0.6 years.

A summary of the Company's unvested stock option activity is as follows:

	Number of Shares	Weighted Average Grant Date Fair Value (CAD)
Unvested, December 31, 2021	**757,082**	**1.58**
Granted	3,107,501	2.43
Vested	(1,497,082)	1.95
Forfeited	(59,999)	2.51
Outstanding, December 31, 2022	**2,307,502**	**2.44**
Granted	2,670,181	1.61
Vested	(2,196,526)	2.20
Forfeited	(289,541)	1.69
Outstanding, December 31, 2023	**2,491,616**	**1.85**
Granted	3,029,000	2.78
Vested	(2,588,666)	2.18
Forfeited	(226,563)	2.28
Outstanding, December 31, 2024	**2,705,387**	**2.54**

During the year ended December 31, 2024, the Company granted an aggregate of 3,029,000 stock options to Directors, Officers, and employees of the Company. A fair value of $6,152 was calculated for these options as measured at the grant date using the Black-Scholes option pricing model.

During the year ended December 31, 2023, the Company granted an aggregate of 2,670,181 stock options to Directors, Officers, employees, and an accounting advisory consultant of the Company. A fair value of $3,193 was calculated for these options as measured at the grant date using the Black-Scholes option pricing model.

During the year ended December 31, 2022, the Company granted an aggregate of 3,107,501 stock options to Directors, Officers, and consultants of the Company. A fair value of $5,795 was calculated for these options as measured at the grant date using the Black-Scholes option pricing model.

The Company's standard stock option vesting schedule calls for 25% every six months commencing six months after the grant date.

During the years ended December 31, 2024, 2023 and 2022 the Company recognized stock option expense of $4,788, $3,464 and $4,332, respectively, for the vested portion of the stock options.

The fair value of all compensatory options granted is estimated on the grant date using the Black-Scholes option pricing model. The weighted average assumptions used in calculating the fair values are as follows:

	As of December 31,		
	2024	**2023**	**2022**
Exercise price	C$5.74	C$2.85	C$4.10
Share price	C$5.75	C$2.85	C$3.98
Risk-free rate	3.70 %	3.89 %	1.95 %
Expected life (in years)	3.11	3.13	3.06
Expected volatility	68.08 %	83.19 %	97.29 %
Expected dividend yield	0 %	0 %	0 %
Weighted average grant date fair value	C$2.78	C$1.61	C$2.43

The Company has elected to utilize the simplified method for determining the expected life of the options. This is due to the options granted being considered "plain vanilla" in accordance with SAB Topic 14 in ASC 718. This simplified method allows for the average of the vesting period and contractual life.

16. Debt

Convertible Promissory Note

On February 14, 2023, the Company issued a secured convertible promissory note (the "Note") in connection with the Alta Mesa asset acquisition. For further details refer to Note 4 - Asset Acquisitions and Sales.

The principal value of the Note is $60,000, and the Note is secured by certain assets of the Company pursuant to the terms of a Pledge Agreement, a Security Agreement, and a Guaranty Agreement between the parties.

The principal portion of the Note is convertible at any time and at the option of the holder into common shares of the Company at a conversion price of $2.9103 per share until maturity on February 14, 2025, and bears interest at a rate of 8.0% per annum. Commencing on June 30, 2023, the Company must make semi-annual interest only payments on June 30 and December 31, of each year through to maturity.

The premium related to the conversion was determined to be $3,813, which was recognized in equity as part of additional paid in capital. The remainder of the proceeds was $56,187 was allocated to the debt component of the Note. The debt component is accreted to the principal balance over its estimated life. During the year ended December 31, 2023, the Company incurred $3,052 of accretion expense, which is included in depreciation, amortization and accretion in the consolidated statements of operations.

During the years ended December 31, 2024 and 2023, the Company incurred interest expense of $1,735 and $3,503, respectively.

During the year ended December 31, 2023, the Company paid $40,000 of the principal balance off, reducing the outstanding debt at that date to $19,239. In February 2024, the debt was converted to equity by the issuance of 6,872,143 common shares to the debt holder.

Note Payable - Related Party

The Company entered into a loan agreement with Boss to borrow up to 200,000 pounds of uranium from Boss. The loan bears interest of 9% and be repayable in 12 months in cash or uranium at the election of Boss. Boss is considered a related party given its minority ownership of JV Alta Mesa.

The principal of the note payable as of December 31, 2024 was $20,108 with accrued interest of $1,531.

17. Related Party Transactions

Related parties include key management of the Company and any entities controlled by these individuals or their direct family members. Key management personnel consist of Directors and senior management including the Executive Chairman, Chief Executive Officer, Chief Financial Officer, Chief Operating Officer, and Chief Legal Officer.

The amounts paid to key management or entities providing similar services are as follows:

	As of December 31,	
	2024	2023
Consulting	$ 257	$ 155
Directors' fees	320	186
Staff costs	2,772	5,956
Stock option expense	3,407	2,708
Total	$ 6,756	$ 9,005

During the year ended December 31, 2024, the Company incurred communications & community engagement consulting fees of $257 (December 31, 2023 - $148) according to a contract with 5 Spot Corporation., a company owned and operated by the spouse of the Company's Executive Chairman. During the year ended December 31, 2023 the Company also incurred finance and accounting consulting fees of $7 according to a contract with Hovan Ventures LLC, a company owned and operated by the former CFO for the Company.

The Company entered into a note payable with Boss, as discussed in Note 16. Boss owns 30% of Alta Mesa JV, as discussed in Note 10.

As of December 31, 2024, and 2023, the following amounts were owing to related parties:

		As of December 31,	
		2024	2023
5-Spot Corporation	Consulting services	$ 10	$ 12
Hovan Ventures LLC	Consulting services	-	7
Officers and Board members	Accrued compensation	836	2,502
Boss	Note payable including accrued interest	21,639	-
Total		$ 22,485	$ 2,521

18. Income Taxes

Net loss before income taxes was generated as follows:

	Years Ended December 31,		
	2024	2023	2022
Domestic - Canada	$ (21,525)	$ (11,666)	$ (12,442)
Foreign – outside of Canada	(52,397)	(14,412)	(10,878)
	$ (73,922)	$ (26,078)	$ (23,320)

Income tax benefit is comprised of the following:

	Years Ended December 31,		
	2024	2023	2022
Current tax expense			
Domestic – Canada	$ -	$ -	$ -
Foreign – outside of Canada	38	2	2
	$ 38	$ 2	$ 2
Deferred tax benefit			
Domestic – Canada	-	-	-
Foreign – outside of Canada	(5,967)	(469)	(167)
	$ (5,967)	$ (469)	$ (167)
Income tax benefit	$ (5,929)	$ (467)	$ (165)

The actual income tax provision differs from the expected amount calculated by applying the Canadian combined federal and provincial corporate tax rates to income before tax. These differences result from the following:

	Years Ended December 31,					
	2024		2023		2022	
Loss before tax	$ (73,922)		$ (26,078)		$ (23,320)	
Federal income tax rate	27	%	27	%	27	%
Income tax recovery based on statutory rate	(19,959)		(7,041)		(6,296)	
Increase (decrease) resulting from:						
Permanent differences	1,257		1,716		972	
Non-controlling interest	1,452		—		—	
Change in valuation allowance	8,499		5,595		4,301	
Other	(631)		9		(53)	
Effect of tax rate in foreign jurisdictions	2,610		457		563	
Tax rate differences and tax rate changes	843		(1,203)		348	
Income tax benefit	$ (5,929)		$ (467)		$ (165)	

Deferred taxes result from the temporary differences between financial reporting carrying amounts and the tax basis of existing assets and liabilities. The table below summarizes the principal components of the deferred tax assets (liabilities) as follows :

	December 31,	
	2024	2023
Deferred tax assets		
Loss carryforwards	$ 24,983	$ 17,155
Mineral rights and properties	4,952	6,273
Inventory	1,489	-
Transaction and financing costs	1,685	2,260
Lease liability	97	128
Warranty liability	815	815
Investment in partnership	3,066	-
Other	197	122
Deferred tax assets	$ 37,284	$ 26,753
Valuation allowance	(34,697)	(24,819)
Net deferred tax asset	$ 2,587	$ 1,934
Deferred tax liabilities		
Investments in equity securities	(786)	(942)
Intangible assets	(35)	(38)
Right of use of assets	(86)	(120)
Mineral rights and properties	(28,142)	(28,306)
Other	(518)	(487)
Deferred tax liabilities	$ (29,567)	$ (29,893)
Deferred tax assets	2,587	1,934
Net deferred tax liability	$ (26,980)	$ (27,959)

Deferred income taxes have not been recorded on the basis differences for investments in consolidated subsidiaries as these basis differences are indefinitely reinvested or will reverse in a non-taxable manner. Quantification of the deferred income tax liability, if any, associated with indefinitely reinvested basis differences is not practicable.

A valuation allowance has been taken against the US federal and state deferred tax assets of $15,700. A valuation allowance has been taken against the Canadian deferred tax assets of $18,997.

As of December 31, 2024 and 2023, the Company has Canadian federal and provincial non-capital loss carryforwards of $66,611 and $49,452, respectively. The Canadian non-capital loss carryforwards expire between 2028 and 2044.

The Company has a US federal net operating loss carryforward of $31,004 and $23,008) with no expiration as of December 31, 2024 and 2023, respectively, and US federal net operating loss carryforwards of $5,658 as of December 31, 2024 and 2023 that expire between 2028 and 2037. In addition, these federal net operating losses that are not subject to expiry are limited to usage at 80% of taxable income in future years. The Company has state net operating loss carryforward of $4,545 with no expiration as of December, 31, 2024 and 2023 and state net operating loss carryforwards of $21,582 and $17,747 as of December 31, 2024 and 2023, respectively, that expire between 2033 and 2044.

Under Section 382 of the Internal Revenue Code of 1986, a corporation that undergoes an ownership change is subject to limitation on its use of pre-change tax attributes and carryforward to offset future taxable income. As of

December 31, 2024 and 2023, we have approximately $11,302 of net operating losses for certain subsidiaries subject to limitation under section 382.

We are subject to the continuous examination of our income tax returns by the Internal Revenue Service and other tax authorities. A change in the assessment of the outcomes of such matters could materially impact our consolidated financial statements. The calculation of tax liabilities involves dealing with uncertainties in the application of complex tax regulations. We recognize liabilities for anticipated tax audit issues based on our estimate of whether, and the extent to which, additional taxes may be required. If we ultimately determine that payment of these amounts is unnecessary, then we reverse the liability and recognize a tax benefit during the period in which we determine that the liability is no longer necessary. We also recognize tax benefits to the extent that it is more likely than not that our positions will be sustained if challenged by the taxing authorities. To the extent we prevail in matters for which liabilities have been established or are required to pay amounts in excess of our liabilities, our effective tax rate in a given period may be materially affected. An unfavorable tax settlement would require cash payments and may result in an increase in our effective tax rate in the year of resolution. A favorable tax settlement would be recognized as a reduction in our effective tax rate in the year of resolution. We do not have a liability related to uncertain positions for income taxes as of December 31, 2024.

19. Segments

The Company's operations are located in the United States and are organized into a single reportable segment; the extraction, recovery and sales of uranium from mineral properties along with the exploration, permitting and evaluation of uranium properties in the United States. This segment has been identified based on the way the CODM assesses the business and allocates resources. This segment is monitored for performance and is consistent with internal financial reporting. The CODM evaluates the performance of the Company's reportable segment based on net income (loss). This is primarily managed and evaluated on a consolidated basis.

20. Quarterly Financial Data (Unaudited)

The following table summarizes the results of operations for the three months ended March 31, 2024, June 30, 2024, September 30, 2024, and December 31, 2024:

	Three months ended			
	March 31,	**June 30,**	**September 30,**	**December 31,**
(in thousands except per share data)				
Revenue	$ 30,394	$ 5,320	$ 9,258	$ 13,362
Cost of goods sold	30,863	10,428	10,600	13,650
Gross profit (loss)	(469)	(5,108)	(1,342)	(288)
Operating costs:				
Depreciation, amortization and accretion	836	783	792	958
Mineral property expenditures	3,896	10,233	3,112	12,522
General and administrative	6,259	5,953	9,973	4,871
Other operating costs	818	894	1,628	1,448
Loss from operations	(12,278)	(22,971)	(16,847)	(20,087)
Other expense	(17)	—	—	—
Interest expense	(399)	(445)	(445)	(446)
Interest income	440	908	651	477
Realized (loss) gain on marketable securities	252	—	—	(4)
Unrealized (loss) gain on marketable securities	(821)	(1,396)	(1,474)	980
Net loss for the period before taxes and non controlling interest	(12,823)	(23,904)	(18,115)	(19,080)
Income tax benefit	(5,929)	—	—	—
Net loss for the period	(6,894)	(23,904)	(18,115)	(19,080)
Net loss for the period attributable to: Non controlling interest shareholders	(660)	(1,980)	(1,980)	(1,981)
Net loss for the period attributable to: Stockholders	$ (6,234)	$ (21,924)	$ (16,135)	$ (17,099)
Basic and diluted loss per share	$ (0.04)	$ (0.12)	$ (0.09)	$ (0.09)
3 month weighted average number of shares	173,486,569	183,237,488	185,184,856	185,943,689

enCore Energy Corp.
Notes to Consolidated Financial Statements
(all amounts in thousands, except for shares)

The following table summarizes the consolidated balance sheets as of March 31, 2024, June 30, 2024, September 30, 2024, and December 31, 2024:

(in thousands except per share data)	March 31, 2024	June 30, 2024	September 30, 2024	December 31, 2024
ASSETS				
Current assets				
Cash and cash equivalents	$ 90,091	$ 55,750	$ 46,348	$ 39,701
Prepaid expenses and other current assets	3,430	7,359	1,688	2,700
Marketable securities	17,594	16,025	20,565	24,046
Inventory	10,784	26,756	27,408	20,967
Total current assets	121,899	105,890	96,009	87,414
Mineral rights and properties, net	274,490	274,490	273,961	271,922
Property, plant and equipment, net	16,277	17,863	18,837	24,017
Intangible assets, net	501	494	493	471
Restricted cash	7,680	7,705	7,751	7,751
Marketable securities, non-current	1,250	1,258	755	837
Right of use assets - operating lease	403	423	378	310
Total assets	$ 422,500	$ 408,123	$ 398,184	$ 392,722
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities				
Accounts payable and accrued liabilities	$ 3,520	$ 3,157	$ 5,579	$ 7,464
Accounts payable - related parties	139	104	200	2,378
Note payable - related party	20,282	20,734	21,187	20,108
Operating lease liabilities, current	177	193	195	130
Total current liabilities	24,118	24,188	27,161	30,080
Deferred tax liabilities	26,980	26,980	26,980	26,980
Asset retirement obligations	10,962	11,113	11,332	16,918
Operating lease liabilities, non-current	240	244	202	202
Total liabilities	62,300	62,525	65,675	74,180
Commitments and contingencies (Note 12)				
Stockholders' equity				
Common stock	367,518	375,070	377,753	380,325
Additional paid-in-capital	50,087	50,954	58,417	59,856
Accumulated deficit	(95,892)	(118,191)	(134,321)	(150,848)
Accumulated other comprehensive gain (loss)	(607)	274	(4,338)	(3,597)
Total stockholders' equity	321,106	308,107	297,511	285,736
Non-controlling interests	39,094	37,491	34,998	32,806
Total equity	360,200	345,598	332,509	318,542
Total liabilities and stockholders' equity	$ 422,500	$ 408,123	$ 398,184	$ 392,722

21. Subsequent Events

On February 26, 2025, the Company executed a second Amendment to the note payable with Boss. Under the amended agreement the Company effectively extended the due date of the final repayment of the note to no later than June 27, 2025

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosures

On November 15, 2024, the Company appointed KPMG LLP ("KPMG") as its independent registered public accounting firm for the fiscal years ended December 31, 2024, 2023 and 2022. From inception through the interim period on or prior to the appointment of KPMG, neither the Company nor anyone on its behalf has consulted with KPMG on either (a) the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on the Company's financial statements, or (b) any matter that was the subject of a disagreement, as that term is defined in Item 304 of Regulation S-K under the Exchange Act ("Regulation S-K") or a reportable event as set forth in Item 304 of Regulation S-K.

On November 15, 2024, upon the Company's request, Davidson & Company LLP ("Davidson") resigned as the Company's independent registered public accounting firm upon the Company retaining KPMG, as noted above. The change was considered and approved by the Company's Audit Committee. The audit reports of Davidson on the financial statements of the Company as of and for the fiscal years ended December 2023 and 2022 in conformity with IFRS Accounting Standards as issued by the International Accounting Standards Board did not contain any adverse opinion or disclaimer of opinion, nor was any opinion qualified or modified as to uncertainty, audit scope or accounting principles. During the fiscal year ended December 31, 2023 and during the period of January 1, 2023 through the date Davidson resigned, there were no disagreements with Davidson on any matter of accounting principles or practices, financial statement disclosure or auditing scope or procedures that, if not resolved to Davidson's satisfaction, would have caused Davidson to make reference in connection with its opinion to the subject matter of the disagreement. No "reportable events", as that term is described in Item 304 of Regulation S-K, occurred within the fiscal year ended December 31, 2023 and subsequently up to the date Davidson resigned.

We provided a copy of this disclosure to Davidson and requested that Davidson furnish a letter addressed to the SEC stating whether it agrees with the above statements, and if not, stating the respects in which it does not agree. A copy of the letter from Davidson addressed to the SEC will be included in the proxy statement for our 2025 Annual Meeting of Shareholders and is also incorporated as Exhibit 16.1 in this report.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures, as that term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Our management, including our principal executive officer ("CEO") and principal financial officer ("CFO"), does not expect that our disclosure controls and procedures over our internal control over financial reporting will prevent all errors and all fraud due to the inherent limitations of internal controls. Because of such limitations, there is a risk that material misstatements will not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

On June 28, 2024, the Company met the requirements to be subject to the Sarbanes-Oxley Act of 2002 Section 404(b) ("SOX") as of December 31, 2024, requiring retroactive application to January 1, 2024 for process level and general information technology controls. Our management, under the supervision and with the participation of our CEO and CFO, has evaluated the design and effectiveness of our disclosure controls and procedures as of December 31, 2024. Based on that evaluation, our CEO and CFO have each concluded that such disclosure controls and procedures were not effective as of December 31, 2024, because of material weaknesses in internal control over financial reporting described below.

Notwithstanding such material weaknesses in our internal control over financial reporting, our management performed additional analyses and other procedures to ensure that our consolidated financial statements were prepared in accordance with U.S. GAAP. Accordingly, management, including our CEO and CFO, believes that the consolidated financial statements included in this Annual Report present fairly, in all material respects, our financial position, results of operations and cash flows as of and for the periods presented, in accordance with those principles.

Management's Annual Report on Internal Control Over Financial Reporting

We maintain internal control over financial reporting, as that term is defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. Internal control over financial reporting is a process designed under the supervision of our CEO and our CFO, overseen by our Board of Directors and Audit Committee, and effected by management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes using the framework in Internal Control – Integrated Framework (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission. Our management, including our CEO and CFO, is responsible for

establishing and maintaining adequate internal control over financial reporting. Such internal control over financial reporting include those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that could have a material effect on the financial statements.

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

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of annual or interim financial statements will not be prevented or detected on a timely basis. Management identified the following material weaknesses in internal control over financial reporting as of December 31, 2024.

- The Company had ineffective general information technology controls ("GITCs") that support the consistent operation of the Company's information technology ("IT") systems, including its enterprise resource planning system. As a result, automated process-level controls and manual controls dependent upon the accuracy and completeness of information derived from those IT systems were also ineffective because they could have been adversely impacted; and
- The Company did not effectively design, implement, or operate process-level control activities related to its financial reporting processes.

Management concluded that these material weaknesses were primarily due to an ineffective control environment that resulted in ineffective risk assessment, information and communications and monitoring activities:

- The Company did not have a sufficient number of trained resources with expertise in and responsibility and accountability for the design, implementation, operation and documentation of internal control over financial reporting and IT systems.
- The Company did not have an effective risk assessment process related to internal control over financial reporting that defined clear financial reporting objectives and evaluated risks, including risks resulting from changes in the external environment and business operations, at a sufficient level of detail to identify all relevant risks of material misstatement to the consolidated financial statements and design and implement internal controls that responded to those risks.
- The Company did not have an effective information and communication process that identified and assessed the source of and controls necessary to ensure the reliability of information used in financial reporting and that communicates relevant information about roles and responsibilities for internal control over financial reporting.
- The Company did not have effective monitoring activities to assess the operation of internal control over financial reporting, including the continued appropriateness of control design and level of documentation maintained to support control effectiveness.

These control deficiencies resulted in no misstatements in the financial statements, however, a reasonable possibility exists that material misstatements in the Company's financial statements will not be prevented or detected on a timely basis.

The Company's independent registered public accounting firm, KPMG LLP ("KPMG"), who audited the consolidated financial statements included in this Annual Report on Form 10-K, has issued an adverse opinion on the effectiveness of the Company's internal control over financial reporting. KPMG's report appears beginning on page 42 of this Annual Report.

Remediation Activities

Until June 28, 2024, the Company was classified as a Foreign Private Issuer and complied with Canadian financial reporting standards (IFRS) and the Canadian Auditing Standards (CAS), which are overseen by the Canadian Public Accountability Board (CPAB) without incident.
With respect to the material weaknesses identified in 2024, management, with oversight from the Audit Committee of the Board of Directors, began implementing corrective measures throughout the time period in 2024 in which the Company found it was required to be compliant with SOX and have continued those efforts into 2025. The Company has invested significant time and resources to enhance the design, implementation, and operation of its internal control over financial reporting to move from its previous compliance under CPAB to the differing standards of SOX.
As of the date of this filing, processes and procedures have been implemented to address these material weaknesses. However, as they have not been in place long enough, their effectiveness cannot yet be fully concluded, and they cannot be considered fully remediated at this time.

- We continued to hire and train our employees to reinforce the importance of a strong control environment and clearly communicate expectations to emphasize responsibilities and the technical requirements for internal controls.
- We utilized a third-party service provider to assist us in evaluating, designing, implementing and testing of our internal control over financial reporting throughout the process of design and implementation of internal control over financial reporting. This service provider now supports the internal audit function.
- We engaged third-party consultants to assist with process mapping and internal control design.
- We developed accounting policies and procedures to assist our organization and assist our accounting and finance team in recording transactions appropriately.
- We enhanced the design of existing control activities and implemented additional process-level control activities, including related GITCs.
- We enhanced user access provisioning and monitoring controls for certain IT systems to enforce appropriate system access and segregation of duties as well as controls supporting change management.
- We designed and implemented additional monitoring controls to assess the consistent operation of controls and to remediate deficiencies.
- We established policies and procedures over the segregation of incompatible duties within our information technology systems and we implemented software used to govern Enterprise Resource Planning development processes.

We are committed to ensuring that our internal control over financial reporting is designed and operating effectively. Management believes the efforts taken to date to enhance the design and effectiveness of controls have been robust and have increased our overall ability to mitigate material financial risk. In fiscal year 2025 we expect to continue to enhance our internal control over financial reporting, including the following:

- Continuing to recruit key positions within our technology, accounting, business operations and other support functions with appropriate qualified experience and ERP knowledge to enhance our risk assessment processes and internal control capabilities, allow for appropriate segregation of duties and change management, and provide appropriate oversight and reviews.
- Designing and implementing a continuous risk assessment process to identify and assess risks of material misstatement and ensure that the impacted financial reporting processes and related internal controls are properly designed and in place to respond to those risks in our financial reporting.
- Developing and implementing a framework to identify risks of material misstatement to our consolidated financial statements and are currently designing controls to mitigate those risks.
- Working to establish a comprehensive GITC evaluation and monitoring program and invest in people and technology to address gaps in IT Systems Security controls, IT Systems Change Management controls, and IT Systems Batch/Program Monitoring controls, including design of controls to address gaps over our GITC's for our ERP and certain other IT systems, which we plan to start implementing in first quarter of 2025.
- Enhancing policies and procedures to improve our overall control environment and monitoring controls around timely evaluation and communication of internal control deficiencies to those parties responsible for taking corrective action, including senior management and the board of directors, as appropriate.

Although we intend to complete the remediation process as promptly as possible, we cannot at this time estimate how long it will take to remediate the material weaknesses described above. We may discover additional material weaknesses that require additional time and resources to remediate, and we may decide to take additional measures to address the material weaknesses or modify the remediation steps described above.

In addition, while certain of the activities described above have continued to enhance our internal control over financial reporting, certain of these newly designed controls have not operated effectively for a sufficient period of time to be able to conclude on effectiveness. We remain committed to continue investing significant time and resources and taking actions to remediate the material weaknesses in our internal control over financial reporting as we work to further enhance our control environment. Until these material weaknesses are remediated, we plan to continue to perform additional analyses and other procedures to ensure that our consolidated financial statements are prepared in accordance with U.S. GAAP.

Changes in Internal Control over Financial Reporting

Other than the material weaknesses discussed above, no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the quarter ended December 31, 2024 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting..

Item 9B. Other Information

On March 2, 2025 (the "Effective Date"), the Board of Directors (the "Board") of enCore Energy Corp. (the "Company") appointed the Company's Chief Legal Officer Robert Willette as Acting Chief Executive Officer, effective immediately.

Mr. Willette will succeed Paul Goranson, who is no longer serving as the Company's Chief Executive Officer or as a member of the Board as of the Effective Date.

Mr. Willette, age 49, has served as the Company's Chief Legal Officer since February 2024. Previously, Mr. Willette served as the Chief Legal Officer, Chief Compliance Officer and Corporate Secretary of ProFrac Holdings Corp. from September 2020 until October 2023. From October 2017 until October 2020, Mr. Willette served as Senior Vice President, General Counsel, Chief Compliance Officer, Corporate Secretary and Chief ESG Officer of CARBO Ceramics, Inc. Mr. Willette holds a B.S., an M.B.A., and a J.D. from the University of Kansas.

Mr. Willette was not appointed pursuant to any arrangement or understanding between him and any other person. There are no family relationships between Mr. Willette and any director or executive officer of the Company and Mr. Willette has no direct or indirect material interest in any transaction required to be disclosed pursuant to Item 404(a) of Regulation S-K.

Item 9C Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

None

Part III

Item 10. Directors, Executive Officers and Corporate Governance

The information required in response to this Item 10 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report.

Item 11. Executive Compensation

The information required in response to this Item 11 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report.

Item 12. Security Ownership of Certain Beneficial Owner and Management and Related Stockholder Matters

The information required in response to this Item 12 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information relating to this item will be included in the proxy statement for our 2025 Annual Meeting of Shareholders and is incorporated by reference in this report.

Item 14. Principal Accountant Fees and Services

The information required in response to this Item 10 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report.

Part IV

Item 15. Exhibits, Financial Statement Schedules

(1) Financial Statements	Page Number
Report of Independent Registered Public Accounting Firm	
Consolidated Balance Sheets as of December 31, 2024 and 2023	
Consolidated Statements of Operations and Comprehensive Income (Loss) for the years ended December 31, 2024, 2023 and 2022	
Consolidated Statements of Changes in Equity for the years ended December 31, 2024, 2023 and 2022	
Consolidated Statements of Cash Flows for the years ended December 31, 2024, 2023 and 2022	
Notes to the Consolidated Financial Statements	

(2) Financial Statement Schedules
Schedules are omitted and are not applicable or not required, or the required information is shown in the financial statements or notes thereto.

(3) Exhibits
Where an exhibit is filed by incorporation by reference to a previously filed registration statement or report, such registration statement or report is identified in parentheses.

Exhibit	Description
3.1	Articles of enCore Energy Corp., as amended on November 6, 2024
4.1*	Description of Securities
4.2*	Warrant Indenture - February 2023
4.3*	Warrant Indenture - December 2022
4.4*	Warrant Indenture - March 2022
4.5*	Warrant Indenture - March 2021
4.6*	Warrant Indenture - October 2020
10.1+	Stock Option Plan (incorporated by reference to Exhibit 99.1 to the Company's Registration Statement on Form S-8 filed with the SEC on July 7, 2023)
10.2+*	enCore Energy Corp. 2024 Long Term Incentive Plan
10.3*	Membership Interest Purchase Agreement, dated November 13, 2022, by and among ERF White Canyon Corp., enCore Energy Corp. and enCore Energy US Corp.
10.4*	Master Transaction Agreement, dated December 5, 2023, by and among enCore Energy Corp., enCore Energy US Corp. and Boss Energy Limited
10.5*	Uranium Loan Agreement, dated December 6, 2023, by and between enCore Energy US Corp. and Boss Energy Limited
10.6*	Amendment No. 2 to Uranium Loan Agreement, effective February 26, 2025, by and between enCore Energy US Corp. and Boss Energy Limited
10.7*	Arrangement Agreement dated September 7, 2021, by and between enCore Energy Corp. and Azarga Uranium Corp.
10.8*	Amendment to Arrangement Agreement, dated November 22, 2021, by and between enCore Energy Corp. and Azarga Uranium Corp.
10.9*+	2024 LTIP Non-employee Director Stock Option Form Award Agreement
10.10*+	2024 LTIP Employee Incentive Stock Option Form Award Agreement
10.11*+	Employment Agreement (William B. Sheriff)
10.12*+	Employment Agreement (Robert Willette)
10.13*+	Employment Agreement (Shona Wilson)
10.14*+	Employment Agreement (Peter Luthiger)
10.15*+	Employment Agreement (Paul Goranson)
14.1*	Code of Business Conduct and Ethics

16.1*	Change in Auditor
19*	Insider Trading Policy
21.1*	List of Subsidiaries
23.1*	Consent of KPMG LLP
23.3*	Consent of Ray Moores, P.E.
23.4*	Consent of Christopher McDowell P.G.
23.5*	Consent of SOLA Project Services LLC
31.1*	Certification of the Chief Executive Officer, pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the U.S. Securities Exchange Act of 1934
31.2*	Certification of the Chief Financial Officer, pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the U.S. Securities Exchange Act of 1934
32.1**	Certification of Principal Executive Officer and Principal Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
96.1	Technical Report on the South Texas Integrated Uranium Projects in Texas, USA, effective December 31, 2024
96.2	Economic Assessment Technical Report for the Gas Hills Uranium Project in Fremont and Natrona Counties, Wyoming, USA, effective date of December 31, 2024
96.3	Technical Report on the Alta Mesa Uranium Projects in Texas, USA, effective December 31, 2024
96.4	Technical Report Summary for the Dewey Burdock Project effective October 8, 2024 (incorporated by reference to Exhibit 96.1 of our Current Report on Form 8-K, filed on January 16, 2025
97.1	Incentive Compensation Recovery Policy(incorporated by reference to Exhibit 97 to the Company's Form 40-F, filed with the SEC on March 28, 2024)
101	Interactive Data File (formatted as iXBRL)
101.INS*	Inline XBRL Instance Document
101.SCH*	Inline XBRL Taxonomy Extension Schema Document
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104*	Cover Page Interactive Data File (formatted as iXBRL and contained in Exhibit 101)

Item 16. Form 10-K Summary

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENCORE ENERGY CORP.

/s/ Robert Willette

March 3, 2025 **Robert Willette**

Interim Chief Executive Officer (Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature		Date
/s/ Robert Willette **Robert Willette**	**Interim Chief Executive Officer (Principal Executive Officer)**	**March 3, 2025**
/s/ Shona Wilson **Shona Wilson**	**Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)**	**March 3, 2025**
/s/ William M. Sheriff **William M. Sheriff**	**Director and Executive Chairman**	**March 3, 2025**
/s/ Dennis E. Stover **Dennis E. Stover**	**Director**	**March 3, 2025**
/s/ William B. Harris **William B. Harris**	**Director**	**March 3, 2025**
/s/ Susan Hoxie-Key **Susan Hoxie-Key**	**Director**	**March 3, 2025**
/s/ Stacy Nieuwoudt **Stacy Nieuwoudt**	**Director**	**March 3, 2025**
/s/ Mark Pelizza **Mark Pelizza**	**Director**	**March 3, 2025**