E3 LITHIUM

Clearwater Project

NI 43-101 Technical Report on Pre-Feasibility Study

Bashaw District Mineral Property Central Alberta, Canada

Technical Report prepared for E3 Lithium Ltd.

Effective date: June 20, 2024

Report prepared by:
DARON ABBEY, M.SC, P.GEO, MATRIX SOLUTIONS INC
ALEX HALUSZKA, M.SC, P.GEO, MATRIX SOLUTIONS INC
MEGHAN KLEIN, P. ENG., SPROULE ASSOCIATES LIMITED
ANTOINE LEFAIVRE, P. ENG., SEDGMAN CANADA LTD
KEITH WILSON, P. ENG., STANTEC INC

CERTIFICATE OF QUALIFIED PERSON

I, Daron G. Abbey, M.Sc., P.Geo., am employed as a Principal Hydrogeologist with Matrix Solutions Inc., A Montrose Environmental Company.

This certificate applies to the technical report titled “Clearwater Project, NI 43-101 Technical Report on Pre-Feasibility Study, Bashaw District Mineral Property, Central Alberta, Canada”, which has an effective date of 20 June, 2024 (the “technical report”).

I am a Professional Geoscientist with the Association of Professional Geoscientists and Engineers of Alberta (190812), which is the affiliation that I am using to authenticate this certificate. I am also registered as a Professional Geoscientist with the Association of Professional Engineers and Geoscientists of Saskatchewan, Professional Geoscientists Ontario and Engineers and Geoscientists of British Columbia. I graduated with a B.Sc., Hons. in Environmental Science from Carleton University in 1996 and an M.Sc. in Earth Sciences, specializing in Hydrogeology from Simon Fraser University in 2000.

I have practiced my profession for 25 years. I have been directly involved in hydrogeology projects during this time including: conceptualization of groundwater flow and solute transport systems, sedimentary geology and three dimensional hydrostratigraphic model development, fractured rock hydrogeology including solute transport, and resource estimation for brine deposits.

As a result of my experience and qualifications, I am a Qualified Person as defined in National Instrument 43–101 *Standards of Disclosure for Mineral Projects* (NI 43–101) for those sections of the technical report that I am responsible for preparing.

I have not visited the Clearwater Project.

I am co-responsible for Sections 2 (except section 2.5), 5, 6, 7, 8, 9, 10, 11, 14, 23, 26 (content pertaining to the mineral resource estimate) and 27 and Subsections 1.1, 1.2, 1.3, 1.5, 1.6, 1.7, 1.8, 1.9, 1.11, 1.12, 1.24 (content pertaining to the mineral resource estimate), 1.25 (content pertaining to the mineral resource estimate), 1.26 (content pertaining to the mineral resource estimate), 3.1, 3.2, 4.1, 4.2, 4.3, 4.4, 4.5, 4.6, 4.11, 4.12, 12.1, 12.3, 25.1, 25.2, 25.3, 25.4, 25.6, 25.16 of the Technical Report.

I am independent of E3 Lithium Ltd. as independence is described by Section 1.5 of NI 43–101.

I have been involved with previous resource estimates for the Bashaw District dated July 11, 2022 and March 21, 2023.

I have read NI 43–101 and the sections of the technical report for which I am responsible have been prepared in compliance with that Instrument.

As of the effective date of the technical report, to the best of my knowledge, information and belief, the sections of the technical report for which I am responsible contain all scientific and technical information that is required to be disclosed to make those sections of the technical report not misleading.

Dated: July 29, 2024

“Signed and sealed”

(Daron G. Abbey, P.Geo.)

CERTIFICATE OF QUALIFIED PERSON

I, Alexander M. Haluszka, M.Sc., P.Geo., am employed as a Principal Hydrogeologist with Matrix Solutions Inc., A Montrose Environmental Company.

This certificate applies to the technical report titled "Clearwater Project, NI 43-101 Technical Report on Pre-Feasibility Study, Bashaw District Mineral Property, Central Alberta, Canada", which has an effective date of 20 June, 2024 (the "technical report").

I am a Professional Geoscientist with the Association of Professional Geoscientists and Engineers of Alberta (79091), which is the affiliation that I am using to authenticate this certificate. I am also registered as a Professional Geoscientist with the Association of Professional Engineers and Geoscientists of Saskatchewan, Engineers and Geoscientists of British Columbia and Engineers Geoscientists Manitoba. I graduated with a B.Sc., Hons. in Geology from the University of Calgary in 2006 and an M.Sc. in Geology, specializing in Carbonate Sedimentology from the University of Calgary in 2009.

I have practiced my profession for 15 years. I have been directly involved in petroleum geology and hydrogeology projects during this time including: subsurface mapping and three dimensional geological modelling of sedimentary reservoirs, geophysical log interpretation, regional hydrodynamics and hydrogeological assessment, and water supply and disposal well drilling and testing.

As a result of my experience and qualifications, I am a Qualified Person as defined in National Instrument 43–101 *Standards of Disclosure for Mineral Projects* (NI 43–101) for those sections of the technical report that I am responsible for preparing.

I visited the Clearwater Project on April 28, 2022.

I am co-responsible for Sections 2 (excepting Subsection 2.5 that I am solely responsible for), 5, 6, 7, 8, 9, 10, 11, 14, 23, 26 (content pertaining to the mineral resource estimate) and 27 and Subsections 1.1, 1.2, 1.3, 1.5, 1.6, 1.7, 1.8, 1.9, 1.11, 1.12, 1.24 (content pertaining to the mineral resource estimate), 1.25 (content pertaining to the mineral resource estimate), 1.26 (content pertaining to the mineral resource estimate), 3.1, 3.2, 4.1, 4.2, 4.3, 4.4, 4.5, 4.6, 4.11, 4.12, 12.1, 12.3, 25.1, 25.2, 25.3, 25.4, 25.6, 25.16 of the Technical Report. I am solely responsible for Subsections 12.7 and 12.8 of the Technical Report.

I am independent of E3 Lithium Ltd. as independence is described by Section 1.5 of NI 43–101.

I have been involved with previous resource estimates for the Bashaw District dated July 11, 2022 and March 21, 2023.

I have read NI 43–101 and the sections of the technical report for which I am responsible have been prepared in compliance with that Instrument.

As of the effective date of the technical report, to the best of my knowledge, information and belief, the sections of the technical report for which I am responsible contain all scientific and technical information that is required to be disclosed to make those sections of the technical report not misleading.

Dated: July 29, 2024

"Signed and sealed"

(Alexander M. Haluszka, P.Geo.)

Sproule

CERTIFICATE OF QUALIFIED PERSON

I, Meghan Klein, P. Eng., am employed as a Senior Manager, Engineering with Sproule Associates Limited at 900, 140 4 Avenue SW, Calgary, Alberta T2P 3N3. Sproule Associates Limited is registered with The Association of Professional Engineers and Geoscientists of Alberta, holding Permit to Practice #:00417.

This certificate applies to the technical report titled "Clearwater Project, NI 43-101 Technical Report on Pre-Feasibility Study, Bashaw District Mineral Property, Central Alberta, Canada", which has an effective date of 20 June, 2024 (the "technical report").

I am a Licenced Engineer of Alberta Association of Professional Engineers and Geoscientists of Alberta, #84981. I graduated from University of Waterloo in 2005 with a Bachelor of Applied Science (Geological Engineering).

I have practiced my profession for 18 years. I have been directly involved in subsurface petroleum, brine and gas reserve and resource evaluations for 18 years, with 1.5 years of experience in lithium from brine resource evaluations.

As a result of my experience and qualifications, I am a Qualified Person as defined in National Instrument 43–101 *Standards of Disclosure for Mineral Projects* (NI 43–101) for those sections of the Technical Report that I am responsible for preparing.

I have not visited the Clearwater Project.

I am responsible for Sections 3, 15, 16, 19, 21, 22, 24, 26 and 27, and Subsections 1.1, 1.2, 1.3, 1.9, 1.13, 1.14, 1.15, 1.19, 1.20, 1.21, 1.22, 1.23, 1.24, 1.25, 1.26, 2.1, 2.2, 2.3, 2.4, 2.6, 2.7, 12.1, 12.4, 25.1, 25.2, 25.7, 25.8, 25.12, 25.13, 25.14, 25.15, 25.16, 25.17 of the Technical Report.

I am independent of E3 Lithium Ltd. as independence is described by Section 1.5 of NI 43–101.

I have had no previous involvement with the Clearwater Project.

I have read NI 43–101 and the sections of the technical report for which I am responsible have been prepared in compliance with that Instrument.

As of the effective date of the technical report, to the best of my knowledge, information and belief, the sections of the technical report for which I am responsible contain all scientific and technical information that is required to be disclosed to make those sections of the technical report not misleading.

Dated: 29 July, 2024

“Signed and sealed”

Meghan Klein, P. Eng.

140 Fourth Avenue SW, Suite 900
Calgary, AB, Canada T2P 3N3
Sproule.com
T +1 403 294 5500 F +1 403 294 5590 TF +1 877 777 6135

SEDGMAN
A MEMBER OF THE CIMIC GROUP
CIMIC

CERTIFICATE OF QUALIFIED PERSON

I, Antoine Lefaivre, P. Eng., am employed as a Lead Process Engineer with Sedgman Novopro.

This certificate applies to the technical report titled "Clearwater Project, NI 43-101 Technical Report on Pre-Feasibility Study, Bashaw District Mineral Property, Central Alberta, Canada", which has an effective date of 20 June, 2024 (the "technical report").

I am an Engineer registered at the *Ordre des Ingénieurs du Québec*, license number 5002027. I graduated from Ecole Polytechnique, Montreal, Canada with a B. Sc. In Chemical Engineering in 2007.

I have practiced my profession for 17 years. I have been directly involved in economic and pre-feasibility studies, as well as process development and due diligence reviews for alkali metals, namely potash, lithium and magnesium in North and South America, Africa and Australia.

As a result of my experience and qualifications, I am a Qualified Person as defined in National Instrument 43–101 *Standards of Disclosure for Mineral Projects* (NI 43–101) for those sections of the technical report that I am responsible for preparing.

I have not visited the Clearwater Project.

I am responsible for Sections 13, 17, 18, 26 and 27 and Subsections 1.1, 1.2, 1.3, 1.9, 1.10, 1.16, 1.17, 1.24, 1.25, 1.26, 2.1, 2.2, 2.3, 2.4, 2.7, 12.1, 12.5, 25.1, 25.5, 25.9, 25.10, 25.16 of the Technical Report.

I am independent of E3 Lithium Ltd. as independence is described by Section 1.5 of NI 43–101.

I have had no previous involvement with the Clearwater Project within the Bashaw District Mineral Property.

I have read NI 43–101 and the sections of the technical report for which I am responsible have been prepared in compliance with that Instrument.

As of the effective date of the technical report, to the best of my knowledge, information and belief, the sections of the technical report for which I am responsible contain all scientific and technical information that is required to be disclosed to make those sections of the technical report not misleading.

Dated: July 29th, 2024

"Signed and sealed"

Antoine Lefaivre, P. Eng.

CERTIFICATE OF QUALIFIED PERSON

I, Keith F. Wilson, P.Eng., am employed as a Consultant - Mining by Stantec Consulting Ltd., 200, 325 – 25 Street NE, Calgary, Alberta T2A 7H8.

This certificate applies to the technical report titled “Clearwater Project, NI 43-101 Technical Report on Pre-Feasibility Study, Bashaw District Mineral Property, Central Alberta, Canada”, which has an effective date of 20 June, 2024 (the “technical report”).

I am a member in-good-standing of the Association of Professional Engineers and Geoscientists of Alberta (Member #59290). I graduated from the University of Saskatchewan, Saskatoon, Saskatchewan, Canada, in 1991. I have practiced my profession for 32 years. I have been directly involved in the complete evaluation and analysis of mineable projects, including surface mineable lithium projects.

As a result of my experience and qualifications, I am a Qualified Person as defined in National Instrument 43–101 *Standards of Disclosure for Mineral Projects* (NI 43–101) for those sections of the technical report that I am responsible for preparing.

I have not visited the property.

I am responsible for Sections 20, 26, 27 and Subsections 1.1, 1.2, 1.3, 1.9, 1.18, 1.24, 1.25, 1.26, 2.1, 2.2, 2.3, 2.4, 2.7, 4.7, 4.8, 4.9, 4.10, 12.1, 12.6, 25.1, 25.11, 25.16 of the Technical Report. I am independent of E3 Lithium Ltd. as independence is described by Section 1.5 of NI 43–101.

I have had no previous involvement with the Bashaw District Mineral Property.

I have read NI 43–101 and the sections of the technical report for which I am responsible have been prepared in compliance with that Instrument.

As of the effective date of the technical report, to the best of my knowledge, information and belief, the sections of the technical report for which I am responsible contain all scientific and technical information that is required to be disclosed to make those sections of the technical report not misleading.

Dated: 29 July, 2024.

“Signed and sealed”

Keith F. Wilson, P.Eng.

Cautionary Note Regarding Forward-Looking Information

This Technical Report contains forward-looking information within the meaning of applicable Canadian securities legislation, including, but not limited to: E3 Lithium Ltd.'s ("E3") objectives, strategies, intentions and expectations; projections; forecasts; economic analysis; estimates; outlook; guidance; schedules; plans; designs; other statements regarding future or estimated financial and operational performance, life of mine, lithium production and sales, revenues and cash flows, capital and operating costs, and budgets; estimated ore grades, throughput and processing; statements regarding anticipated exploration, drilling, development, construction and permitting; statements regarding indications from, and potential impacts of, drilling results; and including, but not limited to: the objectives, strategies, intentions, expectations, production, cost, capital and exploration expenditure guidance, recovery estimates, and the estimated economics of the Clearwater Project, including the planned annual throughput rate, the timing and volume of lithium production from the Clearwater Project; processing facilities and events that may affect the E3's proposed operations, including projected power requirements and other project infrastructure, equipment and materials requirements; anticipated cash flows from the Clearwater Project and related liquidity requirements; the anticipated effect of external factors on proposed revenue and/or mining activities, such as commodity prices and metal price assumptions, estimation of Mineral Reserves and Mineral Resources, mine life projections, environmental liabilities, reclamation costs, economic outlook, government regulation of mining operations, the entering into of major contracts required for development and/or operations; potential environmental, physical, social and economic impacts and plans, measures, and requirements to address such impacts; and other expectations regarding community relations and social licence to operate.

All statements in this Technical Report that address events or developments that E3 expects to occur in the future are forward-looking information. Generally, although not always, forward-looking information can be identified by the use of forward-looking language such as "plans", "expects", "budgets", "schedules", "estimates", "forecasts", "intends", "anticipates", "believes", or variations of such words and phrases, and statements that certain actions, events or results "may", "could", "would", "might", "will be taken", "will occur" or "will be achieved". All such forward-looking information are based on the opinions and estimates of E3's management as of the date such statements are made. All of the forward-looking information in this Technical Report are qualified by this Cautionary Note.

Forward-looking information and statements are not, and cannot be, a guarantee of future results or events. Forward-looking information and statements are based on, among other things, opinions, assumptions, estimates and analyses that, while considered reasonable at the date the forward-looking information statements are provided, inherently are subject to significant risks, uncertainties, contingencies, and other factors that may cause actual results and events to be materially different from those expressed or implied by the forward-looking information statements. The material factors or assumptions that E3 identified and applied in drawing conclusions or making forecasts or projections set out in the forward-looking information and statements include, but are not limited to: the factors identified in Sections 1.11, 1.12, 14 and 25 (and the tables and figures identified thereunder) of this Technical Report, which may affect the Brine Resource estimate; the forward-looking statements and factors identified in Sections 1.13, 1.14, 15 and 25 (and the tables and figures identified thereunder) of this Technical Report, which may affect the Brine Reserve estimate; the metallurgical recovery estimates identified in Section 13 of this Technical Report; the assumptions identified in Sections 14.4 and 14.6 of this Technical Report as being used in evaluating prospects for eventual economic extraction; the assumptions identified in Section 15.2 and Section 15.3 (and the tables and figures identified thereunder) of this Technical Report as forming the basis for converting Brine Resources to Brine Reserves, as well as the assumptions identified in Section 16; the design parameters set forth in Section 15 and Section 16 (and the tables and figures identified thereunder); the assumptions relating to the production schedule in Section 16 (and the tables and figures identified thereunder); the design and equipment assumptions identified in Section 16, Section 17, and Section 18 of this Technical Report (and the tables and figures identified thereunder); the general assumptions identified in Section 1.15, Section 1.16, Section 1.17, Section 1.18, Section 1.19, Section 1.20, Section 1.21, Section 1.22, Section 16, Section 17, Section 18, Section 19, Section 20, Section 21, Section 22, and Section 25 (and the tables and figures identified thereunder) of this Technical Report, as well as the tables included therein; dilution and mining recovery assumptions; the success of mining, processing, exploration and development activities; the accuracy of geological, mining and metallurgical estimates; anticipated metals prices and the costs of production; no significant unanticipated operational or technical difficulties; the execution of E3's business and growth strategies; the availability of additional financing, if needed; the availability of personnel for exploration, development, and operational projects and ongoing employee relations; maintaining good relations with the communities surrounding the Clearwater Project; governmental regulation of mining activities and oil and gas in Alberta, including regulations relating to prices, taxes, royalties, land tenure, land use, importing and exporting of minerals and environmental protection; environmental regulations, which mandate, among other things, the maintenance of air and water quality standards and land reclamation, limitations on the general, transportation, storage and disposal of solid and hazardous waste; no significant unanticipated events or changes relating to regulatory, environmental, health and safety matters; no contests over title to E3's properties; no significant unanticipated litigation; certain tax matters; and no significant and continuing adverse changes in general, political, security or economic conditions or conditions in the financial markets (including commodity prices and foreign exchange rates).

The risks, uncertainties, contingencies and other factors that may cause actual results to differ materially from those expressed or implied by the forward-looking information statements may include, but are not limited to: risks generally associated with mining operations, including problems related to weather and climate; economic factors, including fluctuations in commodity prices, currency, energy prices, interest rates and inflation; uncertainties related to the proposed development and operation of the Clearwater Project; changes to production, cost and other estimates; changes to the taxation laws in the jurisdictions in which E3 operates; fluctuations in the price and availability of infrastructure, energy and other commodities; the market price of E3's common shares; compliance with government regulations, including anti-bribery and corruption laws, environmental regulations and internal control over financial reporting; challenges to mineral or surface rights to E3's properties; the failure to obtain required licences, permits, approvals or clearances from governmental authorities, including environmental permits, on a timely basis or at all; climate change; risks related to community relations and opposition, including social unrest; the ability to service E3's debt; uncertainties relating to Brine Reserve and Brine Resource estimates, including in relation to the geology, continuity, grade and estimates of Brine Reserves and Brine Resources and the potential for variations in grade and recovery rates; volatile financial markets and the ability to obtain additional financing; hedging transactions; the inability to insure against all risks; litigation risks; cybersecurity risks; dependence on key personnel and employee relations; operational risks and hazards, including unanticipated environmental, industrial and geological events and developments, and failure of plant, equipment, processes, transportation and other infrastructure to operate as anticipated; uncertain costs of reclamation activities, and the final outcome thereof; as well as other factors identified and as described in more detail under the heading "Risk Factors" in E3's most recent Annual Information Form and E3's other filings with Canadian securities regulators, which may be viewed at www.sedarplus.ca.

Important Notice

This report was prepared as National Instrument 43-101 Technical Report for E3 Lithium Ltd. (E3) by Matrix Solutions Inc, Sproule Associates Limited, Sedgman Canada Ltd., and Stantec Consulting Inc., collectively the Report Authors. The quality of information, conclusions, and estimates contained herein is consistent with the level of effort involved in Report Authors' services, based on i) information available at the time of preparation, ii) data supplied by outside sources, and iii) the assumptions, conditions, and qualifications set forth in this report. This report is intended for use by E3 subject to terms and conditions of its individual contracts with each of the Report Authors. Except for the purposes legislated under Canadian provincial and territorial securities law, any other uses of this report by any third party is at that party's sole risk.

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1.0 SUMMARY

1.1 Introduction

Mr. Daron Abbey, P.Geo., Mr. Alex Haluszka, P.Geo., Ms. Meghan Klein, P.Eng., Mr. Antoine Lefaivre, P.Eng., and Mr. Keith Wilson, P.Eng., prepared a technical report (the Report) on the Clearwater Project (the Project) within the Bashaw District Mineral Property for E3 Lithium Ltd. (E3). The Clearwater Project will host the planned Central Processing Facility.

1.2 Terms of Reference

The Report was prepared to support disclosures in E3's news releases dated June 26, 2024, entitled "E3 Outlines Clearwater Project Pre-Feasibility Study And Confirms Lithium Reserves" and dated 29 August 2024, entitled "E3 Lithium Files Clearwater Project NI 43-101 Technical Report".

The Report provides an updated Brine Resource estimate and first-time disclosure of Brine Reserves as a result of a pre-feasibility study completed during 2024 (the 2024 PFS).

The Canadian Institute of Mining, Metallurgy and Petroleum (CIM) Definition Standards for Mineral Resources and Mineral Reserves (May 2014; the 2014 CIM Definition Standards), incorporated by reference into National Instrument NI 43-101 (NI 43-101) does not currently include brines as part of the "mineral" (2014 CIM Definition Standards) or "mineral project" (NI 43-101) definitions. However, there is a general acceptance within the industry that reporting brine projects as mineral projects is appropriate, and a brine-specific guideline exists (2012 CIM Best Practice Guidelines for Resource and Reserve Estimation for Lithium Brines). For the purposes of this Report, the estimates are referred to as Brine Resources or Brine Reserves, with the exception of statutory Item headings.

The Report uses Canadian English. Monetary units are reported in US dollars (US$) unless otherwise noted. Units are metric units unless otherwise noted.

1.3 Report Terms

The Report uses the following terms:

- Bashaw District Mineral Property: referred to as the Bashaw District;

- Clearwater Project: also referred to as the Project; a rectangular area within the Bashaw District, which includes the drainage area, the infrastructure associated with the drainage area, and the Central Processing Facility;
- The Central Processing Facility: the infrastructure required for processing produced brine into saleable product.

The Report uses reservoir engineering terminology for most parameters rather than hydrogeological terminology to align with the proposed recovery method via existing oilfield technologies (wells, pumps, and pipelines) to extract the lithium-rich brine from the reservoir and supply it to a process facility that will use a direct lithium extraction technology. In some cases, however, hydrogeological terms can be used. A summary of key terminology is provided in Table 1-1.

E3 adapted the standard oilfield approach for evaluating data distribution and variance which involves calculating "P10," "P50," and "P90" values. These metrics represent the 10th, 50th, and 90th percentile values in a given data distribution. The 50th percentile value (P50) represents a median and is not a mean value but these terms are equal for normal data distributions. Average (mean) values are presented in some sections of the Report where appropriate and are described as such.

1.4 Project Setting

The Clearwater Project is located within E3's Bashaw District brine-hosted minerals licence area in central Alberta, between the cities of Red Deer and Calgary. The City of Red Deer is located at the junction of Alberta Provincial Highway 2 and Highway 11. Highway 2 is the main corridor between Edmonton and Calgary and runs north–south along the west boundary of the Clearwater Project area.

Major and secondary provincial highways, and all-weather roads developed to support oil/gas infrastructure, occur throughout the permit areas. Additional access is provided by secondary one- or two-lane all-weather roads, and numerous all weather and dry weather gravel roads. Grid roads run every mile throughout the Project area, providing access year-round.

There are international airports in Calgary and Edmonton. Red Deer hosts a regional airport. Two rail lines (Canadian National and Canadian Pacific + Kansas City Southern) are present throughout the area and connect to the major centers of Edmonton and Calgary.

Calgary has a continental climate with severe winters, no dry season, warm summers and strong seasonality. Extraction operations will be conducted on a year-round basis. As this is a reservoir that will be produced using direct lithium extraction technology to extract lithium from brine, there are no climate related limitations to resource extraction, unlike the situation for salar-type deposits.

Table 1-1: Reservoir Engineering versus Hydrogeology Terminology

<table>
<tr><th>Reservoir Term(s)</th><th colspan="2">Equivalent Hydrogeological Term</th></tr>
<tr><td>Reservoir; net pay</td><td>Aquifer</td><td rowspan="2">Hydrostratigraphic units</td></tr>
<tr><td>Seal</td><td>Aquitard</td></tr>
<tr><td>Producible volume*</td><td colspan="2">Specific yield*</td></tr>
<tr><td>Total system compressibility product</td><td colspan="2">Specific storage</td></tr>
<tr><td>Irreducible water saturation</td><td colspan="2">Specific retention</td></tr>
<tr><td>Fluid mobility</td><td colspan="2">Hydraulic conductivity</td></tr>
<tr><td>Viscosity-corrected permeability thickness</td><td colspan="2">Transmissivity</td></tr>
<tr><td>Flow test</td><td colspan="2">Pumping test</td></tr>
<tr><td>Build-up; shut-in period</td><td colspan="2">Pumping test recovery period</td></tr>
<tr><td>Fall-off</td><td colspan="2">Injection test recovery period</td></tr>
</table>

Note: * Producible volume relies on reservoir drive mechanisms whereas specific yield assumes gravity drainage.

The region is dominated by farmland with numerous creeks and wetlands occurring throughout the district. The dominant landform is undulating glacial till plains, with about 30% as hummocky, rolling, and undulating uplands. The average elevation is 750 masl, but ranges from 500 masl near the Alberta–Saskatchewan border to 1,250 masl near Calgary and 700 masl near Edmonton. The Red Deer River is the dominant riparian feature, flowing south–southeast from the middle of the North Bashaw area within the Bashaw District to Drumheller in the in the southeast of the permit area.

Accommodation, food, fuel, and supplies are readily obtained in the City of Red Deer and the towns of Olds, Sylvan Lake and Innisfail. Internet and phone coverage are available throughout the permit areas. Many trained workers live in the area and work in the oil and gas sector. These workers have the skills and expertise required to develop lithium from their related experience in oil and gas. There is a significant amount of infrastructure in the area to support over 70 years of oil and gas development operations.

1.5 Mineral Tenure, Surface Rights, and Royalties

The Bashaw District consists of 46 brine-hosted minerals licences that overlie the Leduc Formation in Southern Alberta covering 333,608 ha. These 46 licences completely or partially intersect the Bashaw District boundary, with 331,847 ha falling within the boundary and 1,760 ha falling outside. The claims are interspersed with privately-owned (freehold) mineral rights. The Clearwater Project within the Bashaw District covers an area of 77,872 ha, and contains all or portions of 10 brine hosted minerals licences (licences 209, 210, 211, 212, 222, 223, 224, 225, 243, and 248) within the Bashaw District.

Amendments to the Metallic Industrial Minerals Tenure legislation came into force on January 1, 2023 (Alberta Energy, Energy Operations Division, 2022), which split the Metallic Industrial Minerals permits into rock-hosted metallic and industrials minerals permits, and brine-hosted minerals leases.

As an eligible rock-hosted minerals permit holder, E3 applied on November 17, 2023 to convert the rock-hosted permits to brine-hosted minerals licences. E3 received 100% of the permits converted to brine-hosted licences on January 26, 2024. These licences have a non-renewable term of five years with an annual rental fee, after which E3 intends to convert the licences to brine-hosted mineral leases.

The mineral permits are interspersed with privately-owned (freehold) land, where the subsurface and/or minerals rights are owned by private individuals and/or companies and not the Crown. The freehold mineral rights do not pose an obstacle to brine assay and mineral processing test work within the mineral permits owned by E3, as E3 can take assays and perform testing over areas for which they own the permits, and extrapolate the data to cover the areas that do not include E3's permits. The reservoir itself is not confined to the E3 permits but spans the whole Bashaw District. Since June 23, 2022, E3 has formed a partnership with Imperial Oil with the option to purchase a number of the freehold mineral rights in the area to fill in some gaps within permit area. In 2024, a number of additional freehold sections were added to the original agreement to further fill in gaps within the Bashaw District. E3 is confident that appropriate agreements with off-setting freehold mineral owners can be arranged, per Alberta Energy Regulator D56 7.7.12(e). Discussions with freehold owners are currently underway. E3 is able to proceed with exploration and development activities under the common-law principle of The Rule of Capture, wherein an exploration company is allowed to extract resources (including brine) from underneath their leased lands, regardless of whether that brine migrated from adjacent unleased lands. The resource volumes in this Report includes all lands within the Bashaw District outline, including both Crown and freehold mineral rights.

Surface rights are owned mainly by private landowners over the Bashaw District, and E3 currently leases three surface locations from private owners for their three well pads.

Drill pad locations will be leased from individual property owners for an annual fee and must be reclaimed when the terms of the surface lease have been fulfilled or terminated. For facilities, surface locations can either be purchased or leased under the same conditions, and it is required that they are also reclaimed when the facility is decommissioned or abandoned.

No private royalties remain over the Project area. There were no known existing non-government royalties over E3's permit areas at the Report effective date.

1.6 Geology and Mineralization

The lithium brine in the Bashaw District is considered to be an example of a lithium-rich brine deposit.

The Bashaw District is in the southwestern part of the Western Canada Sedimentary Basin. In this area, the Upper Devonian (Frasnian) sediments of the Woodbend Group were deposited in a shallow inland sea bounded by the emergent Peace River Arch to the northwest and the West Alberta Ridge to the southwest, creating a barrier between the sea and the open ancestral Pacific to the west.

The Woodbend Group is dominated by basin siltstone, shale and carbonate of the Majeau Lake and Cooking Lake Formations. The Duvernay and Ireton Formations surround and cap the reef complexes of the Leduc Formation. The flooded carbonate platform of the Cooking Lake Formation provided structural highs and a favorable environment for the extensive reef buildups of the Leduc Formation.

Deep-seated faulting related to the Precambrian basement and the Snowbird Tectonic Zone appear to have at least partial control on the distribution of reefs and some of the oil fields in the area.

Lithofacies within the Leduc Formation were identified, interpreted, and delineated based on sedimentary structures and textures observed in core, and can be related to trends of porosity and permeability. The three key facies are:

- Facies-1: Leduc reef flat to reef margin facies;
- Facies-2: Leduc Mixed reef interior open lagoon to reef flat facies;
- Facies-3: Leduc reef interior restricted to open lagoon facies.

Based on the available data, the facies were assumed to be vertically continuous throughout the reef thickness.

The main lithium accumulations in E3's properties occur within brines contained within dolomitized reefs complexes of Devonian-aged Leduc Formation, with a secondary accumulation occurring at a higher elevation in the biostromal development in the Nisku Formation of the Devonian Winterburn Group. Consequently, lithium-brine mineralization in the Project area consists of lithium-enriched brines that are hosted in porous and permeable reservoirs associated with the Devonian carbonate reef complexes. The specific emplacement method for the lithium in these reservoirs is currently unknown.

E3's current conceptualization of the Brine Resource is that the lithium grade is homogeneously distributed within the connected reservoir of the Bashaw District due to the high permeability and connected nature of the reservoir.

Data collected during E3's 2022 evaluation well program supports this theory, as all samples collected have a very narrow range of P10–P90 concentrations. The lithium data were collected across the 65+ townships of the Bashaw District, and E3's evaluation well program acquired lithium concentrations across the vertical extent of the Leduc Formation.

Additionally, major cation and anion geochemistry concentrations do not vary significantly across the Bashaw District, which further supports the interpretation that the brine is continuous.

1.7 History

E3's 2022 drill program was the first in Alberta specifically drilled to test brine for lithium concentrations. At the Report effective date, no other operator in Alberta had drilled wells solely to evaluate lithium concentrations in subsurface brines.

Historical testing of lithium in brine, prior to E3, was conducted as part of routine chemistry analysis by oil and gas operators in the area from produced water related to oil and gas production. These data were compiled in a comprehensive overview of the mineral potential of formation waters from across Alberta by the Government of Alberta. Subsequent collection of brine water from actively producing oil and gas wells was conducted by the Alberta Geological Survey and the brine water was analyzed for lithium.

E3 completed a review of the brine and hydrocarbon drilling history within the Project area, reviewed available historical third-party core data and historical well logs, examined results of hydrocarbon industry drill stem tests, examined historical production, injection and disposal volumes, and assessed historical and publicly available lithium data. E3 conducted brine sampling from existing hydrocarbon wells, including wellhead, test separator, large volume, and repeat sampling. The company has drilled and completed two wells, and completed a third-party well, estimated Brine Resources and Brine Reserves, and completed engineering studies, culminating in the 2024 PFS.

1.8 Drilling and Sampling

From June 2022 to January 2023, E3 conducted a three-well exploration program. The exploration program included drilling two wells and acquiring a third. The locations were selected to maximize the description of geological, reservoir, and lithium concentrations within the Project area.

A collar locator logging tool was used to identify collar locations. The tool consists of a set of magnetic coils that detect changes in the magnetic field cased by the presence of the metallic collars. During drilling, directional tools measure the well bottom-hole location using sensors behind the drill bit which measure inclination and azimuth. The data are transmitted to surface using electromagnetic signals that are interpreted in real time to guide the well trajectory. Post-drill, directional surveys were run on all three locations, to total depths, using advanced directional sensors and broad frequency electromagnetic signals.

The general sampling procedure was consistent for samples collected either from existing oil and gas infrastructure or dedicated exploration wells installed and sampled by E3. All samples were collected into 1 L opaque amber bottles. The bottles were filled to the top to ensure no air was trapped at the top. The cap was screwed on and then sealed with electrical tape. Each bottle was labeled with the unique well identifier, sample interval depth, date, and an E3 custody seal was applied for security.

Samples were submitted either to Bureau Veritas Laboratories (Bureau Veritas Red Deer, Edmonton and/or Calgary), or AGAT Laboratories Calgary (AGAT), or SGS Geochemistry Division, Lakefield, ON (SGS Lakefield) for processing. Each of these laboratories are accredited by the Canadian Association of Laboratory Accreditation Inc as meeting general requirements for the competence of testing and calibration laboratories. The laboratories are independent of E3.

In the laboratory, samples were first degassed to primarily get rid of hydrogen sulfide. Samples received at the individual laboratories were vigorously mixed and a subset of sample was placed in a digestion tube. Samples were subject to acid digest, which depending on the laboratory could be a single or double digest. Post-digestion, samples were then diluted and run through an inductively coupled plasma–optical emission spectrometry (ICP–OES) machine for trace metal analysis. Samples collected from the three E3 wells had trace metals measured by SGS Lakefield. The samples were diluted with 20% HCl for the ICP-OES and 2% HCl for the inductively coupled plasma–mass spectrometry (ICP-MS) method. A combination of both practices is used for the 30 trace metal analyses.

Quality assurance and quality control (QA/QC) measures consisted of insertion of certified reference materials (standards). The standard was based on a Leduc reservoir brine. Analyses included in the Report all passed the QA/QC testing.

E3 collected 102 Leduc brine samples across the Bashaw District. Of the sample data contained in this Report, a subset of these samples come from the same well (55 unique locations sampled over the Bashaw District). At each well location, there may be different vertical intervals of the Leduc Aquifer that were sampled, and there are also samples that were collected from the same well and interval over time (47 repeat samples). Vertically different samples were treated as unique samples so that vertical heterogeneity within the reservoir could be evaluated. For intervals with multiple samples over time, a mean value was calculated after a qualitative review that the samples had low variance in the temporal scale. Based on the sampling results, the Leduc reservoir is enriched in lithium in sampled wells across the Bashaw District, and the data demonstrate consistency throughout both horizontally and vertically.

Sampling to the Report effective date included samples from 44 individual wells, representing a temporal variation dataset, with four or more repeat samples collected at several locations. The lithium concentrations remain steady in a relatively narrow P90 to P10 distribution over time in the Bashaw District. The Bashaw District data density, based on the 44 individual well locations is 0.013/km^2, and is 0.031/km^2 based on the 102 unique samples.

1.9 Data Verification

The QPs verified the information used in their discipline areas was acceptable for support of Brine Resource and Brine Reserve estimates and in the economic analysis that supports the Brine Reserves.

1.10 Metallurgical Testwork

Testwork for the Clearwater Project was conducted by, or supervised by SGS in Lakefield Ontario, Bureau Veritas in Calgary and Edmonton Alberta, as well as vendor and E3 in-house laboratories and piloting facilities during the period of 2019–2024 and remains ongoing. To date testing has focused on the novel direct lithium extraction process for the extraction of lithium from the Leduc reservoir brine. Other technologies to be incorporated into the process flowsheet include reverse osmosis, ion exchange for polishing and removal of cations, precipitation, evaporation and crystallization processes to produce battery-grade lithium hydroxide monohydrate.

Multiple manganate ion exchange and aluminate sorbent systems were evaluated at bench scale to demonstrate lithium recovery from the Leduc brine. Manganate ion exchange achieved lithium extraction recoveries from 89.1– 90.8% while the aluminate sorbents achieved recoveries from 90.0–95.0%.

A manganate ion exchange and an aluminate sorbent technology were each selected for pilot testing at E3's field pilot plant facility. The pilot project was to demonstrate the two technologies at larger scale and to further understand and demonstrate lithium recovery under continuously operating conditions. In addition to their extraction performance, these technologies were proven to significantly reject other brine species (Na, K, Ca, Mg, B) to facilitate impurity removal producing a high-quality lithium chloride eluate, and have been used in commercial applications. Following piloting, an aluminate sorbent was identified as the preferred technology.

The results of ion exchange testwork indicated that small quantities of lithium was adsorbed during the process and therefore the regenerate solution should be recycled to recover this lithium. Reverse osmosis testing was completed on the ion exchange treated direct lithium extraction eluate to concentrate the lithium in solution. The reverse osmosis concentrate contained approximately 6,000 mg/L of lithium while the permeate contained only 8 mg/L indicating <1% of lithium losses in the reverse osmosis process while achieving approximately a 7.5 times increase in lithium concentration.

Lithium was tested for further concentration by evaporating the reverse osmosis concentrate solution. Calcium and silicon levels in the evaporator concentrate were lower than expected, indicating these species also partially precipitated.

A recycle stream of mother liquor was passed through an ion exchange to separate sodium from lithium with the lithium product stream able to return to the lithium chloride evaporation step for additional lithium precipitation. Lithium carbonate was then redissolved and reacted with hydrated lime resulting in a 2.85% lithium hydroxide (LiOH) solution containing solid calcium carbonate. Following the removal of calcium carbonate solids, the remaining calcium in the lithium hydroxide solution was removed to <1.0 mg/L through ion exchange. Evaporation testing of the lithium hydroxide solution showed that it could be concentrated to 13% LiOH with the concentrated brine then sent to a crude lithium hydroxide monohydrate crystallizer which was operated under vacuum. Analysis of the mother liquor showed a concentration factor of approximately 11.85 times. Washing of the crystal demonstrated the ability to reduce impurities on the crystal including aluminum, iron, potassium, silicon, sodium, zinc, carbonate, chloride, and sulfate.

The produced crystals were dewatered, washed and redissolved to produce a feed to the pure lithium hydroxide monohydrate crystallizer. The final crystallization produced crystals with a d50 of 800–850 µm, and washed crystals met the battery grade specification.

Testing demonstrated consistent direct lithium extraction lithium recovery from brine with a reported average of 95.04% ±0.79% observed during testing. The low variability of the brine chemistry will enable consistent lithium recovery. Downstream of the direct lithium extraction process, it is anticipated that 98% of the lithium recovered by the direct lithium extraction will be converted into solid lithium carbonate. The redissolution of lithium carbonate and precipitation of lithium hydroxide will recover 96.9% of the lithium for a final overall process recovery of 90.4% lithium into a lithium hydroxide monohydrate product.

Brine chemistry across the Bashaw district is relatively consistent with a narrow range of concentrations for lithium as well as for other species. E3 has collected samples across 65+ townships and has also collected a vertical brine profile in their most recent test wells and found the composition to have low variability.

Silicon, boron, sodium, magnesium and calcium are the expected deleterious elements present in the Leduc brine. The concentrations of these elements are expected to be steady during plant operations. In compliance with battery grade lithium hydroxide monohydrate specifications, product is to contain <0.01 mg/L each of silicon, boron, sodium, magnesium and calcium.

1.11 Brine Resource Estimation

The Brine Resource estimate for the Bashaw District is based on reservoir geometries and properties populated in a 3D geological and reservoir model developed using Petrel™ (Schlumberger Information Solutions, undated). Petrel™ is a commercial software platform that integrates geological and reservoir data.

The geological model included the following reservoir characteristics: area geometry, structure, thickness, porosity, permeability, and lithium concentrations (grade). The 3D geological model was used to geostatistically simulate and evaluate scenarios of connected porosity in the reservoir that were used as the basis for the resource estimate in the model domain. The model was validated in part based on existing and project developed maps and cross-sections of depositional environments, facies, diagenesis and oil and gas pools. Additional validation by the QPs was completed by detailed review of the raw input data to the geological model, suitability of the geostatistical approaches applied, and output grids for the model.

Pore volume was estimated from the reservoir model grid by summing the porosity values from all the cells above a minimum porosity threshold connected to an adjacent cell also meeting the threshold (and for defining the resource, containing a measured lithium sample within the connected pore volume). Effective porosity was the parameter evaluated in this assessment.

Based on statistical evaluation and the completion of the vertical grade profiling, the QP determined that the sample dataset represented a large regional area across the Bashaw District and within this dataset, lithium grade variance was small and there were no mappable spatial trends in the grade. This result is expected for a regionally continuous, hydraulically connected aquifer, where the emplaced lithium has been regionally distributed through advective and dispersive groundwater flow over a long period of geological time. Based on this analysis, the QPs believe it is reasonable to apply the P50 lithium concentration of 75.5 mg/L as the lithium grade across the Bashaw District to estimate the volumes for Measured and Indicated Brine Resource volumes.

Permeability was evaluated to support development of effective porosity cutoffs and to determine if the resource has a reasonable prospect of eventual economic extraction. Linear regression analysis was done on the core data to evaluate the relationship between porosity and permeability. The effective porosity/permeability relationship was interpreted to indicate a high confidence that 6% effective porosity could be associated with an extractable resource volume and 2% a moderate confidence.

The Bashaw District resource area was treated as a single continuous reservoir based on continuity in porosity (>2% effective porosity connected pore volume), consistency in lithium grade, and observed pressure dynamics. A cut-off grade was not used in this assessment because the grade within the reservoir was determined to be homogeneous and therefore the factor controlling the resource volume will be the effective porosity distribution and connectivity in the reservoir.

The geostatistical simulation of 50 equally plausible 3D effective porosity distributions for the resource quantified the uncertainty in the estimated brine connected pore volume (and by extension resource volume) accounting for the uncertainty in the measured data. Specifically, based on the current data locations, density and range in the effective porosity values, the difference in overall P10 and P90 brine connected pore volume using a 2% porosity cut-off between all 50 realizations is 12%. Based on the low range in variance of the connected pore volume and validation of the output results described above, the QPs selected the P50 volume calculated from the 50 realizations that evaluated the connected effective porosity as the basis for the estimate.

The Brine Resource estimate excludes hydrocarbons and any pore volume associated with them.

Measured Brine Resources are assumed to have permeability values at reservoir core porosities (which represent effective porosity) of 6% or greater range from 0.1–to 30,000 mD with a regression fit of approximately 10 mD. Indicated Brine Resources are assumed to have permeability values at reservoir core porosities (which represent effective porosity) of 2% or greater range from 0.04–1,000 mD with a regression fit of approximately 1 mD.

1.12 Brine Resource Statement

The estimates are reported inclusive of those Brine Resources converted to Brine Reserves using the 2014 CIM Definition Standards. Brine Resources that are not Brine Reserves do not have demonstrated economic viability.

The Qualified Persons for the Brine Resource estimates are Mr. Daron Abbey, P. Geo and Alex Haluszka, P. Geo, both of Matrix Solutions Inc.

The estimates have an effective date of June 20, 2024. A summary of the Measured, Indicated and Measured + Indicated Brine Resource volumes for the Bashaw District is provided in Table 1-2 and for the Clearwater Project area in Table 1-3. Table 1-3 is not additive to Table 1-2.

Table 1-2: Bashaw District Total, Measured, and Indicated Resource Estimates

Confidence Category	Original Lithium In Place (t Li)	Original Lithium In Place (t lithium carbonate equivalent)	Original Lithium In Place (t lithium hydroxide monohydrate)*
Clearwater Measured Brine Resource (excluding hydrocarbon pore volumes)	1,256,300	6,687,200	7,595,500
Clearwater Indicated Brine Resource (excluding hydrocarbon pore volumes)	1,790,500	9,530,900	10,825,500
Clearwater Measured and Indicated Brine Resources OLIP (excluding hydrocarbon pore volumes)	3,046,800	16,218,100	18,421,000

Table 1-3: Clearwater Project Area Total, Measured and Indicated Resource Estimates as a Subset of the Bashaw District

Confidence Category	Original Lithium In Place (t Li)	Original Lithium In Place (t lithium carbonate equivalent)	Original Lithium In Place (t lithium hydroxide monohydrate)*
Clearwater Measured Brine Resource (excluding hydrocarbon pore volumes)	340,200	1,811,100	2,057,100
Clearwater Indicated Brine Resource (excluding hydrocarbon pore volumes)	222,500	1,184,500	1,345,300
Clearwater Measured and Indicated Brine Resources OLIP (excluding hydrocarbon pore volumes)	562,800	2,995,600	3,402,500

Notes to Accompany Brine Resource Tables

1. Brine Resources are reported using the 2014 CIM Definition Standards, and are inclusive of those Brine Resources converted to Brine Reserves. Brine Resources that are not Brine Reserves do not have demonstrated economic viability.
2. The Qualified Persons for the estimate are Daron Abbey, P. Geo and Alex Haluszka, P. Geo, both of Matrix Solutions Inc.
3. The estimates have an effective date of June 20, 2024.
4. Brine Resources are confined within the Leduc Formation within the Bashaw District.
5. Numbers have been rounded.
6. Table 1-3 is not additive to Table 1-2.

The following are comments and discussion from the QPs on factors and risks that may affect the potential development of the Brine Resource:

- The resource estimate methodology is dependant on the assumption that the depleted brine will be reinjected into the host reservoir. It is important to note that emerging regulations in some jurisdictions, and currently in the Project jurisdiction, mandate fluid reinjection as part of brine production schemes. Reinjection brings challenges as well as benefits, as lithium depleted brine will be added to the reservoir and dilution of the resource over time will need to be managed. However, this type of production scheme has been used for oil and gas reservoir development for decades and fluid breakthrough can be managed, with the field optimized in real time. These aspects of production need to be evaluated as part of the reserves analysis, as by-passed brine will need to be excluded from the Brine Reserves versus the Brine Resource;
- The Brine Resource estimate used a geostatistical approach accounting for uncertainty in porosity measurements that leveraged a significant amount of publicly available data from historical petroleum exploration in the reservoir. Therefore, existing porosity, permeability, and grade measurements are still mainly concentrated in the hydrocarbon saturated portions of the reservoir. E3's exploration drilling in the central, water saturated portion of the reservoir, has improved the confidence that the reservoir properties inferred from this data are still representative of the full reservoir area but it is important to note that the relationship of porosity to permeability is variable across the Bashaw District area. The specific factors controlling variability (geological facies, diagenetic processes) were not discretely represented in the current reservoir model other than a linear decrease of porosity versus depth inferred from the broad dataset. While the P50 connected porosity volume may be an overestimate of the actual connected porosity in the reservoir, the QPs believe that the geostatistical approach captured the potential range of uncertainty in connected porosity that could impact the resource estimate which was found to be 12% (P10–P90);
- It is known that there are fractures in the reservoir that make up a component of the connected porosity system. For the purposes of this Report, the porosity system has been treated as a single continuum of porosity, and de-weighted the fracture porosity by using the K90 core permeability measurements rather than the maximum permeability. If the exchange between matrix and fractures is delayed, this could affect the ability to extract the Brine Resource from the matrix porosity. This can be evaluated through additional flow testing and operational monitoring of production.

1.13 Brine Reserves Estimation

The proposed mining method will use production wells to pump brine from the Leduc Formation. The reference point for the Brine Reserves is defined as the saleable product from the Central Processing Facility.

The Brine Reserve estimate was conservatively modeled and stated as a Proven Brine Reserve for Year 1 through Year 5 of full-scale extraction, and a Probable Brine Reserve for Year 6 through Year 50 of full-scale extraction. The distinction between Proven and Probable Brine Reserves is based on industry precedent from similar projects.

The Measured and Indicated Mineral Resources correspond to the total producible lithium in place in the Bashaw District and the Clearwater Project Area while the Proven and Probable Brine Reserves represent the recoverable lithium, which is a subset of the producible lithium demonstrating the portion of producible lithium that can be extracted and sold during the planned life of the Project.

Lithium grade will decline over time as the reinjected lithium depleted brine makes its way to the production well. A conservative approach has been taken which allows both the production and injection wells to be perforated across the entire Leduc Formation thickness for the first five years of production, and then the injection wells will have a workover completed so that injection is limited to the lower portion of the reservoir while the production wells continue to produce from the entire reservoir thickness, to maximize overall recovery.

1.14 Brine Reserves Statement

The Proven and Probable Brine Reserves estimate for the proposed 50-year production period is summarized in Table 1-4, and includes reductions for both facility on-time and processing losses during lithium recovery.

Brine Reserves are reported at the point of saleable product from the Central Processing Facility, using the 2014 CIM Definition Standards, and have an effective date of June 20, 2024. The Qualified Person for the estimate is Ms. Meghan Klein, P. Eng., of Sproule Associates Limited.

Table 1-4: P50 Proven and Probable Brine Reserves for the Clearwater Project

Clearwater Project Reserves	Li (t)	Lithium Carbonate Equivalent (t)	Lithium Hydroxide Monohydrate (t)
Proven Reserves (initial 5 years)	26,550	141,450	160,700
Probable Reserves (6 to 50 years)	187,200	996,400	1,131,7000
Total Proven and Probable	***213,750***	***1,137,850***	***1,292,400***

Note:

1. Brine Reserves are reported at the reference point of the saleable product from the Central Processing Facility, and have an effective date of June 20, 2024. Brine Reserves are reported using the 2014 CIM Definition Standards.
2. The Qualified Person for the estimate is Ms. Meghan Klein, P. Eng., of Sproule Associates Limited.
3. Brine Reserves are reported assuming 2,500 m^3/d/well, initial capital of $2,465 million, average operating costs of $7,250/t lithium hydroxide monohydrate, 92% on-time and 90.4% lithium recovery.
4. Numbers have been rounded.

Factors that may affect the estimate include:

- E3's ability to raise sufficient capital to develop the Clearwater Project as outlined in Section 16. Should insufficient capital be available, a smaller-scale development could be considered, which would recover fewer Brine Reserves than those included in the 2024 PFS;
- Other factors that could affect development of the Brine Reserves are changes in the assumptions regarding reservoir factors (brine volume, reservoir deliverability, lithium concentration); cost factors (operating and capital costs); processing factors (facility on time, processing losses); lithium market and pricing; supply of materials (both building materials and process materials and chemicals); environmental, social license, and regulatory considerations (approvals and licenses).

1.15 Mining Methods

To produce lithium, the reservoir water will be pumped to the surface from a production well as produced brine. The produced brine will be processed at the surface to remove the lithium, leveraging direct lithium extraction technology. The lithium-depleted brine will be injected into the reservoir using injection wells for pressure support.

The reservoir development plan is to drill up to five wells from each of the 38 pads in the project area, for a total of 93 producers and 93 injectors, each with a brine rate of 2,500 m^3/d. This approach allows for the centralized gathering of fluids, reducing road and pipeline construction. The inlet volume required for the Central Processing Facility is 232,500m^3/d, which can be met and maintained from the 93 wells for the full 50 years of production, without requiring sustaining well capital. The preliminary locations of the 38 multi-well pads are not being publicly disclosed at this time, to ensure that E3's engagement and stakeholder consultation can occur in the appropriate sequence.

Multiple well and pump design scenarios were evaluated to determine the optimal design for the project. The optimal design was determined by balancing total project costs with executability, including lead-time for casing, tubing, and pumps, to deliver the total brine production of 232,500 m^3/d to the facility inlet. The evaluation included the reservoir deliverability and injection capacity of a variety of well network patterns and downhole spacing scenarios.

The total field development program will require approximately 1,300 days of drilling. With six rigs, this would take approximately six months of drill time. This includes the initial survey, clearing, and civil work required for well pad construction and access.

A simulation model formed the basis for the reservoir development plan, which in turn formed the basis for the production profile associated with the Brine Reserve estimate. The simulation model was developed using a numerical simulation to generate a type curve for well performance, which was rolled up to generate the full project production profile which was input into an economic model. The model is based on a standard "five-spot" well network pattern where the production well is in the center of the pattern and drains the reservoir within its pattern boundary. The boundaries are described as "no-flow" as the fluid on the opposite side of the pattern boundary is pulled towards the production well in the center of its pattern. The model was calibrated using the rates and pressure data from E3's 2022 flow test.

Drilling wells for brine production and injection will use the same practices and proven technology as hydrocarbon drilling. Lithium-enriched brine from the Leduc Formation will be produced from the subsurface to surface using a downhole artificial lift system placed within the well.

To offset lithium grade decline, after five years of production and injection, a workover will be performed on the injector wells to shut in the top quarter of the reservoir, thereby forcing re-injected lithium depleted brine into the lower portion of the Leduc Reservoir from Year 6 to Year 50. This strategy was chosen to optimize drainage across the well network as the lithium-depleted brine injected into the reservoir travels more quickly through the upper portion of the Leduc Reservoir, which has higher porosity and permeability compared to the lower portion. By forcing injection into the lower portion of the Leduc Reservoir, the lithium depleted brine sweeps the lithium enriched brine towards to producer wells more effectively.

1.16 Recovery Methods

The proposed Clearwater Project will produce battery-grade lithium hydroxide monohydrate from Leduc Formation brines. The lithium enriched brine will be extracted from the reservoir through the producer wells and transferred by pipeline to the Central Processing Facility. The Central Processing Facility will process 232,500 m^3/d of brine to produce battery-grade hydroxide monohydrate at the expected combined lithium processing recovery of 90.4% from the direct lithium extraction technology, lithium refining and conversion processes. The brine has a lithium concentration of 75 mg/L ± 5 mg/L. The planned production life is 50 years. Applying the assumed on-time of 92% for the Central Processing Facility, the initial facility production rate is 32,250 t/a.

The Central Processing Facility will include the following major process units:

- Brine degassing treatment and acid gas handling;
- Lithium recovery from the brine by direct lithium extraction;
- Lithium-depleted evaporative water recovery and reinjection;
- Lithium chloride purification and concentration by nanofiltration, reverse osmosis, ion exchange, and mechanical vapor recompression evaporation;
- Lithium chloride carbonation to lithium carbonate;
- Lithium carbonate conversion to lithium hydroxide monohydrate;
- Lithium hydroxide monohydrate evaporation, crystallization, drying and packaging.

Under normal operations, the Central Processing Facility will not be reliant on fresh water to meet the process water demands. All process demands for pure water will be met by recycling reverse osmosis and evaporator distillates. Raw materials used in the process will include hydrochloric acid and sodium hydroxide for pH control and ion exchange regeneration, soda ash (Na_2CO_3) for the carbonate conversion process and lime (CaO) for hydroxide conversion process.

1.17 Project Infrastructure

The key infrastructure envisaged in the 2024 PFS includes:

- Power supply (grid tie-in and third-party cogeneration unit);
- Access road(s);
- Storm water pond;

- Central Processing Facility (gas compression and injection; pre-treatment – degassing; direct lithium extraction and post-direct lithium extraction treatment; lithium hydroxide plant);
- Office space, control room, laboratory, security, first aid;
- Warehouse for storage of spares and sales product;
- Communications (fibre-optic cable);
- Multi-well pads;
- Pipelines.

E3 is seeking a third-party to construct and operate a cogeneration facility to be located adjacent to the Central Processing Facility to supply power to the facility and the well pads. The Central Processing Facility will require an electrical power supply of approximately 85 MW, and field production infrastructure, dominated by downhole pump requirements, will require approximately 80 MW. The facility will include natural gas-fired turbines. A portion of the steam generated from waste heat will be used within the Central Processing Facility to satisfy all utility steam requirements during normal operations.

The brine will be extracted from the Leduc reservoir using a series of wells. A total of 38 pads will be cleared. Each pad will host five wells, each drilled using direction techniques in an "S" pattern so that they intersect the Leduc reservoir vertically and will be completed across the entire Leduc interval. The well configuration will be four producers and one injector for 19 of the pad locations and one producer and four injectors for the remaining 19 pad locations. A total of 93 producers and 93 injectors will be completed across the brine production area. Once the drill activities are complete, the production wells will have an electric submersible pump installed, and each pad site will have a transformer, local motor control centre and electrical building. The pipeline will be tied into the pad site and further tied into the main pipeline gathering system for the Central Processing Facility.

The pipeline will operate in a two-phase flow regime along its length. This is not uncommon in the oil and gas industry, and operating a two-phase pipeline operation is well understood. The pipeline corridors and trench for the brine supply pipelines will be shared with the brine reinjection pipeline network. There will be approximately 200 km each of brine production and brine reinjection pipelines. The pipeline segments will be buried in a trench, below the frost line, and will be insulated below grade.

The provisional Central Processing Facility site was selected due to its strategic location, which will benefit from its proximity to existing infrastructure including roads, and rail, facilitating efficient transport of chemicals and supplies to the Central Processing Facility and from the Central Processing Facility to offtake customers. The proposed Central Processing Facility will be located strategically on a previously disturbed site that is within proximity of existing regional infrastructure.

Solid waste will be transferred by truck to a local waste handling disposal facility. Acid gas will be injected into disposal wells located at the Central Processing Facility. There is a local market for calcium carbonate and E3 is exploring ways to sell this product into the cement industry and eliminate this product as waste.

Surface water will be collected in a stormwater pond. Runoff not collected in the pond will be directed around the site using ditches and culverts.

Personnel to construct, operate, maintain, and support the operation are expected to come from local towns and cities, and a camp will not be required at the Central Processing Facility.

1.18 Environmental, Permitting and Social Considerations

1.18.1 Environmental Considerations

There have been two environmental studies completed to date on the proposed potential site for the Central Processing Facility, including a reconnaissance-level survey to identify potential environmental constraints, and a Phase 1 environmental site assessment to identify potential environmental concerns, including those from previous land uses.

No evaporative ponds or tailings ponds are required at the Central Processing Facility. However, a stormwater pond will be required to manage surface water run-off, which will be designed to meet a 1-in-100-year flood event. Secondary containment requirements for ponds as outlined in Directive 055 (Storage Requirements for the Upstream Petroleum Industry) (D055) will be used for stormwater run-off ponds within the facility boundary. Surface water run-off within the Central Processing Facility boundary will be managed in accordance with the industrial wastewater limits.

A groundwater monitoring program will likely be required to monitor and detect potential impacts to fresh groundwater resources in the vicinity of the Central Processing Facility that may occur from production of brine or through ongoing operational activities.

The Central Processing Facility will only produce calcium carbonate ($CaCO_3$), a solid waste product that will be transported to a licenced waste management facility. E3 is not planning to construct a landfill at the Central Processing Facility. No liquid industrial waste will result from the process. E3 is investigating mechanisms to sell the calcium carbonate produced to the cement industry, thereby creating a zero-waste facility.

1.18.2 Closure and Reclamation Planning

The submission of a conceptual reclamation plan is required for the Central Processing Facility to fulfil the goals identified under the *Environmental Protection and Enhancement Act* related to pollution prevention, mitigating environment impacts, and not impairing future use of the environment.

The objective of a Conservation and Reclamation Plan for the well pads and pipelines is to return the land to equivalent land capability, which requires that landscape, soil, biological resources and water be conserved and protected.

As set out in Alberta Energy Regulator (AER) Directive 90 (Brine-Hosted Mineral Resource Development) (D090), E3 will need to estimate the total Project liabilities, including the costs of providing care and custody and the cost to permanently end operations, which includes abandoning, remediating and reclaiming the proposed site. E3 will be required to pay facility abandonment and reclamation costs, and an abandonment fee per well and reclamation costs per well under Directive 011 (Licensee Liability Rating Program: Updated Industry Parameters and Liability Costs) (D011). The facility abandonment cost and well reclamation costs used in the Licensee Liability Rating formula were based on the most recent cost assessment conducted by the Alberta Energy Regulator. The closure cost estimate is a high-level estimate of the costs to suspend, abandon, remediate, and reclaim the proposed site, as well as provide care and custody from shutdown of operations through to site reclamation. Facility abandonment and reclamation costs were calculated based on the instruction in AER Directive 6 (Licensee Liability Rating (LLR) Program) (D006) for well equivalents for a facility designed to process 232,500 m^3/d, and total C$36.7 million.

1.18.3 Permitting Considerations

E3 has identified four key regulatory pathways that will be used to organize required regulatory applications for the overall permitting and approval of the Project. These four regulatory pathways are organized as follows:

- Central Processing Facility regulatory requirements;
- Brine-hosted mineral scheme;
- Well pads, and associated production and injection wells;
- Pipelines.

The regulatory approval of the Central Processing Facility will also require the regulatory applications, assessments and guidance from various Alberta Energy Regulator Directives. E3 has not yet applied for the regulatory approvals required for the Project. Key components that will require permitting include: the Central Processing Facility, well pads with mineral wells, and accompanying mineral scheme(s), and pipeline network required to transport brine to the Central Processing Facility for processing and refinement.

1.18.4 Social Considerations

E3 has developed a strategy to address social licence for the project, which is a combination of adhering to instructions in various Alberta Energy Regulator Directives, and in the *Responsible Energy Development Act,* and a planned broader consultation process.

The Clearwater Project is located on freehold-owned surface land. There currently appears to be no Project activities that will occur on Crown land, and therefore Crown consultation activities should not be required. It is unlikely that there will be any Aboriginal Consultation Office determination on level of consultation for the Project. E3 will seek to engage with First Nations to understand and address their values, concerns and interests in the Project, and potentially explore options for economic development.

1.19 Markets and Contracts

Lithium is a key element in the production of batteries for electric vehicles, consumer electronics, and grid-scale energy storage. The demand for lithium has been growing rapidly in recent years, driven by the global transition to sustainable energy solutions and the rapid adoption of lithium-ion batteries. Market studies indicate a robust upward trend, with lithium demand expected to triple by 2030.

Global lithium mine supply is projected to reach a substantial level by 2033. However, increasingly stringent environmental, social, and governance requirements and lengthy regulatory processes in many jurisdictions are likely to extend the timelines for new lithium projects, adding long-term pressure on supply. Many projects are still in the early stages, and the difference between nameplate capacity and output should be noted as new and existing facilities will produce volumes below their nameplate capacity, resulting in limited visibility on supply sources beyond the next 5–10 years. Consequently, supply growth beyond 2033 is expected to be limited, despite some early-stage projects potentially coming online during this period.

The two main lithium products, lithium carbonate and lithium hydroxide monohydrate, are crucial for manufacturing the cathodes used in lithium-ion batteries. Lithium carbonate is widely used due to its stable chemical properties and straightforward production process. Lithium hydroxide monohydrate is increasingly preferred for high-nickel cathode chemistries due to its superior performance characteristics. As consumers, especially those outside China, seek higher energy densities and longer cycle lives, the demand for lithium hydroxide monohydrate is projected to grow significantly.

A detailed future pricing study for lithium chemicals was developed for the Project using data from trusted research firms, covering battery-grade lithium carbonate and lithium hydroxide monohydrate prices for China, Japan, and Korea, as well as spodumene prices for China. Prices at approximately US$70/kg (US$70,000/t) for lithium hydroxide monohydrate, as seen in 2022, are considered unsustainable. It is anticipated that prices will stabilize at levels beneficial for both producers and consumers. While volatility has been a feature of the market in recent years and is expected to continue, there may be periods of higher-than-expected prices during times of extreme tightness. The price forecast for lithium hydroxide monohydrate was based on yearly forecast from 2027 to 2034, where the long-term price used was the 2023 price of $31,000/t lithium hydroxide monohydrate, in Benchmark Mineral Intelligence's Q1 2024 report, published in March 2024.

It is anticipated that material contracts for the Project will include power, concentrating, refining, transportation, handling, and product offtake. Any future contracts would be in line with similar contracts in Alberta. No contracts were in place at the Report effective date.

1.20 Capital Cost Estimates

The capital cost estimate for the 2024 PFS was completed by breaking the facilities down into a work breakdown structure and estimating each section using industry standard estimating practices for an AACE International Class 4 estimate (-30% to +50%). The capital cost estimate includes engineering, materials, equipment, and labour required to design, build, and construct a commercial lithium extraction well network, gathering system and Central Processing Facility and produce lithium hydroxide monohydrate over a 50-year production life.

The capital cost estimate was completed by an experienced cost estimator who determined its accuracy as Class 4 by assessing the extent and maturity of the estimate input information (e.g. vendor-supplied data, key planning and design deliverables). All costs for the project were estimated and calculated in Canadian dollars and converted to United States dollars. All costs outlined in this Report are in 2024 US$ with an exchange rate of CA$:US$ of 1.34.

The capital cost estimate was developed using budgetary vendor quotes, historical pricing, and industry accepted allowances. Budgetary vendor quotes were used for all major equipment, while minor equipment was estimated using either historical data or budgetary vendor quotes. Where allowances have been used, the allowance has been identified in the report for clarity. Factors were used to determine installed equipment cost.

The capital cost estimate includes both direct and indirect field costs:

- Direct field costs included factored equipment cost, materials which have been adjusted for winterization, labour which has been adjusted for productivity expected in central Alberta, utilities and offsites, and freight calculated as 8% of equipment and material cost. Installation factors were selected for the equipment based on the equipment type and the level of modularization expected from the vendor. Labour rates were based on current rates for southern Alberta and it is expected that offsite fabrication and module assembly will be the preferred execution strategy;
- Indirect field costs were calculated as a percentage of the direct field cost and includes contractor indirect costs such as contractor management and supervision, temporary construction facilities, temporary construction services, construction equipment, small tools and consumables, and contractor overhead and profit. Engineering is included as a percentage of the total field cost.

Sustaining capital starts in the second year of operation, and the cashflow analysis assumes that no sustaining capital is required in the first year of operation. When the facility sustaining capital is calculated on an annual basis for the first 25 operating years, the cost is approximately US$26 million per year. Beyond 25 years, sustaining capital was increased to account for maintenance of the older facility. The increased sustaining capital was calculated by dividing the initial equipment capital cost, as invested in Year 1, by 25 and spreading it across Years 26–50 of the production life. This increased sustaining capital is intended to cover the cost of replacing Central Processing Facility equipment between Year 26 and the final year of production operation.

A cost allocation of US$27.4 million was included at the end of the production life to cover abandonment, decommissioning and reclamation of the production and injection wells, the pipelines and the Central Processing Facility.

The total capital cost for the project is summarized in Table 1-5.

1.21 Operating Cost Estimates

The annual operating cost was calculated using quantity and pricing information provided through vendor quotes or by engineering calculation. An allowance was assumed for some miscellaneous costs.

The operating costs are average annual costs over the 50-year operating life of the project and are reported in US$/year. The operating expenditure was based on an average production rate of 25,850 t/a of battery-grade lithium hydroxide monohydrate and a nameplate facility capacity of 32,250 t/a with a 92% on-time over the project production life of 50 years.

Table 1-5: Capital Cost Estimate Summary

Area	Installed Cost (US$ x 1,000)
Brine production and brine injection wells	378,496
Brine production and injection pipelines	448,134
Brine treatment	448,146
Lithium extraction, purification and carbonation	403,971
Lithium hydroxide, crystallization and packaging	255,144
Chemical handling	52,741
Site preparation (allowance)	31,095
Buildings (allowance)	49,751
First fills	55,970
Contingency	342,028
Total	***2,465,476***

Operating costs include allocations for:

- Fixed and variable costs for the wells;
- Planned maintenance activities;
- Fiber optic monitoring system;
- Reagents and transport;
- Electrical power;
- Waste disposal;
- Operations personnel;
- Miscellaneous costs.

The average annual operating expenditure for the field and the Central Processing Facility is summarized in Table 1-6.

Table 1-6: Operating Cost Summary

Description	Average Annual Operating Cost (US$/year x 1,000)
Well fixed costs	3,640
Well variable costs	1,749
Maintenance	26,491
Pipeline leak detection	109
Chemicals and trucking	48,512
Power and natural gas	79,667
Waste disposal	2,484
Operations personnel	19,372
Miscellaneous cost	5,380
Total Average Annual Operating Cost	***187,404***

1.22 Economic Analysis

1.22.1 Forward-Looking Information Note

Please refer to the note at the front of this Report for information on forward-looking information.

1.22.2 Economic Analysis

The economic analysis combines the production profile from the Leduc reservoir provided by the production well network and the estimated capital and operating costs to extract, pipe and process the brine and further refine it into a saleable lithium hydroxide monohydrate product.

The economic analysis was prepared using a discounted cash flow economic model, showing both pre-tax and post-tax results. The model includes government royalties and taxes and there are no commercial royalties/payments expected. Any Freehold lands within the Project are assumed to have a royalty rate that is equivalent to government royalties. The results include net present value (NPV) for an 8% discount rate, internal rate of return (IRR), and a sensitivity analysis of key inputs.

The basis of the discounted cash flow model includes:

- Discount rate of 8% per year used to discount all future cashflows;
- Assumed start of production in 2027 with Year 1 of the model being the start of capital expenditure;

- Unlevered basis, which assumes that the project is financed from E3's equity and does not account for any interest expenses (debt) or interest income (cash);
- Real basis, which means that all future cash flows are accounted for in 2024 dollars with no provision for inflation or escalation of costs or revenue;
- Applicable taxes and royalties have been accounted for;
- A third-party research firm price forecast was used for the duration of the project with an average selling price of US$31,344/t over the producing life (weighted for production);
- Base case technical and economic outputs ;
- All amounts estimated in Canadian dollars (C$) were converted to United States dollars (US$) at an exchange rate of 1.34 (C$:US$) unless otherwise specified.

The Central Processing Facility will produce lithium hydroxide monohydrate, and all estimates for the production quantities and price forecasts use lithium hydroxide monohydrate, with the Brine Reserves reported in both lithium carbonate equivalent and lithium hydroxide monohydrate.

The following royalties were applied:

- Alberta crown royalties for metallic and industrial minerals are set at 1% gross mine revenue before payout, and the greater of either 1% gross mine-mouth revenue or 12% net revenue after payout;
- Payout is defined as the date that the total project costs are equivalent to total revenues on the project, or four years after production start for the 2024 PFS;

A blended Federal and Provincial income tax rate of 23% was used to calculate the projected income taxes payable. The cash flow model does not include any allowances for government funding for critical minerals.

A summary of the key base case economic outputs from the economic analysis are presented in Table 1-7. The post-tax NPV is US$3.72 billion, the post-tax IRR is 24.6%, and the payback period is four years.

Table 1-7: Economic Evaluation Results

Evaluation Metric	Units	Years 1–25	50 Year Production Life
Lithium hydroxide monohydrate average production	t/year	29,593	25,850
Lithium hydroxide monohydrate price	US$/t	31,601	31,344
Total initial capital	US$ x1,000	2,465,476	2,465,476
Total sustaining capital	US$ x1,000	375,755	1,263,699
Total maintenance capital	US$ x1,000	282,022	507,640
Total abandonment capital	US$ x1,000	—	27,404
Average annual operating cost	US$/year	194,776	187,403
Average operating cost	US$/t	6,582	7,250
Annual EBITDA	US$ x1,000	648,070	530,844
Project unlevered IRR (pre-tax)	%	29.26	
Project unlevered IRR (after-tax)	%	24.65	
Project NPV @ 8% (after-tax)	US$ x1,000	3,720,301	
Payback period	Years	4	4

Note: EBITDA = earnings before taxation, depreciation and amortization. IRR = internal rate of return. NPV = net present value.

1.23 Sensitivity Analysis

A sensitivity analysis was carried out by varying single parameters while keeping others unchanged to isolate their impact on the projected NPV8% and IRR. The analysis was completed under after-tax conditions. The sensitivity analysis was conducted for each of the key project parameters:

- Initial capital cost estimate, major maintenance and abandonment (±20%);
- Operating expense and maintenance (±20%);
- Selling price (±20%).

Grade sensitivity was excluded for this Project on the following basis:

- Brine-hosted lithium mineralization (grade) is demonstrably homogeneous both laterally and vertically across the entire Bashaw District;
- Declining grade, due to the reinjected lithium depleted brine from the injection wells reaching the production wells, fully or partially, is included in the economic analysis;

- A sensitivity for variation in overall production volumes disconnects the production profile from the infrastructure as described, and is considered to be unrepresentative.

The results of the sensitivity analysis demonstrate the economic viability of the project through the ranges of ±20% for the variable change of capital cost estimate, operating cost estimate, and selling price. The project economics show the most significant impact to variations of the selling price followed by the capital cost estimate, and finally the operating cost estimate.

1.24 Risks and Opportunities

1.24.1 Risks

The QPs identified the following risks in their areas of expertise.

Brine Resource and Brine Reserve Estimates

- Re-injection fails to maintain reservoir pressure;
- Existing porosity, permeability, and grade measurements are mainly concentrated in the hydrocarbon pools within the Bashaw District;
- Transfer of lithium from the rock matrix porosity to fractures could be delayed.

Reservoir Development Plan

- Potential production and injection rates for full Leduc perforations are currently calculated based on a single flow test;
- Hydraulic continuity between interior and margin areas was inferred from regional data, not physically validated by long-term pressure transient data;
- The assumptions as to timing and magnitude of break-through of lithium-depleted brine that is re-injected into the reservoir reaching the production wells;
- The ability to maintain reservoir pressures to support production flow rates has been modelled and will need to be validated through actual operational data;
- Relationship of porosity to permeability is variable across the Bashaw District area and the specific factors controlling variability (geological facies, diagenetic processes) have not been discretely represented in the current reservoir model.

Process Design

- Lithium sorbent degradation rates over time/cycles could be higher than anticipated;
- Consumption/fouling rates for reverse osmosis membranes could be higher than anticipated;
- Solids in brine are greater than anticipated, resulting in the need for solid removal equipment;
- Sour brine could have a detrimental long term impact on sorbent degradation;
- Potential for H2S to evolve from brine in the plant;
- Materials of construction failure:
  - Availability at 92% is at the high end for most mineral processing plants however is achieved from industrial processing facilities currently. Currently minor maintenance requirements are assumed to align into major maintenance windows; however, a detailed minor maintenance schedule shall be constructed to update the total availability;
- Despite the chemistry being well understood for the post direct lithium extraction stages, varying incoming chemistry and reagent quality is a risk and further testwork is being conducted to understand the impact;

Regulatory

- Pore space competition between brine-hosted resources and reserves and carbon capture utilization and storage interests;
- Freehold land ownership and crown ownership for mineral permits not held by E3 will require agreements to equitably produce.

Economics

- Operating costs and capital costs could be higher than estimated;
- Lithium prices could be lower than estimated.

1.24.2 Opportunities

There is opportunity to further increase confidence in the Brine Resource and Brine Reserve estimates and reduce risks through additional data collection, flow tests and monitoring during future construction, commissioning, and production phases and incorporation and assessment of new information using the reservoir model.

Recovery is based on current testwork conducted by E3 and independent vendors and there is both a risk and opportunity on the total recovery, which will be further explored by future testwork and pilot plant trials.

E3 is investigating mechanisms to sell the calcium carbonate produced to the cement industry, thereby creating another potential revenue source and a zero-waste facility.

1.25 Interpretation and Conclusions

Under the assumptions described in this Report, the proposed LOM plan is achievable, and the economic analysis supports declaration of Brine Reserves.

1.26 Recommendations

Two work phases are recommended.

The first work phase should include:

- Brine Resources and Brine Reserves: additional drilling and testing of existing wells; reservoir simulations;
- Lithium processing: testing to observe the sorbent longevity and susceptibility of thermal shock, any sorbent performance variability or loading limitation, and optimal column configuration; additional testing to de-risk unit operations;
- Engineering studies.

The total estimated costs for Phase 1 are approximately US$9 million, and will culminate in the completion of a feasibility study.

Assuming the results of the feasibility study are positive, E3 should evaluate a final investment decision in a second work phase, which may include:

- Brine Resources and Brine Reserves: additional drilling and testing of existing wells; reservoir simulations;
- Engineering studies.

The total estimated costs for Phase 2 are approximately US$57 million.

2.0 INTRODUCTION

2.1 Introduction

Mr. Daron Abbey, P.Geo., Mr. Alex Haluszka, P.Geo., Ms. Meghan Klein, P.Eng., Mr. Antoine Lefaivre, P.Eng., and Mr. Keith Wilson, P.Eng., prepared a technical report (the Report) on the Clearwater Project (the Project) within the Bashaw District Mineral Property for E3 Lithium Ltd. (E3). The Clearwater Project will host the planned Central Processing Facility. The Project location is shown in Figure 2-1.

2.2 Terms of Reference

The Report was prepared to support disclosures in E3's news releases dated June 26, 2024, entitled "E3 Outlines Clearwater Project Pre-Feasibility Study And Confirms Lithium Reserves" and dated 29 August 2024, entitled "E3 Lithium Files Clearwater Project NI 43-101 Technical Report".

The Report provides an updated Brine Resource estimate and first-time disclosure of Brine Reserves as a result of a pre-feasibility study completed during 2024 (the 2024 PFS).

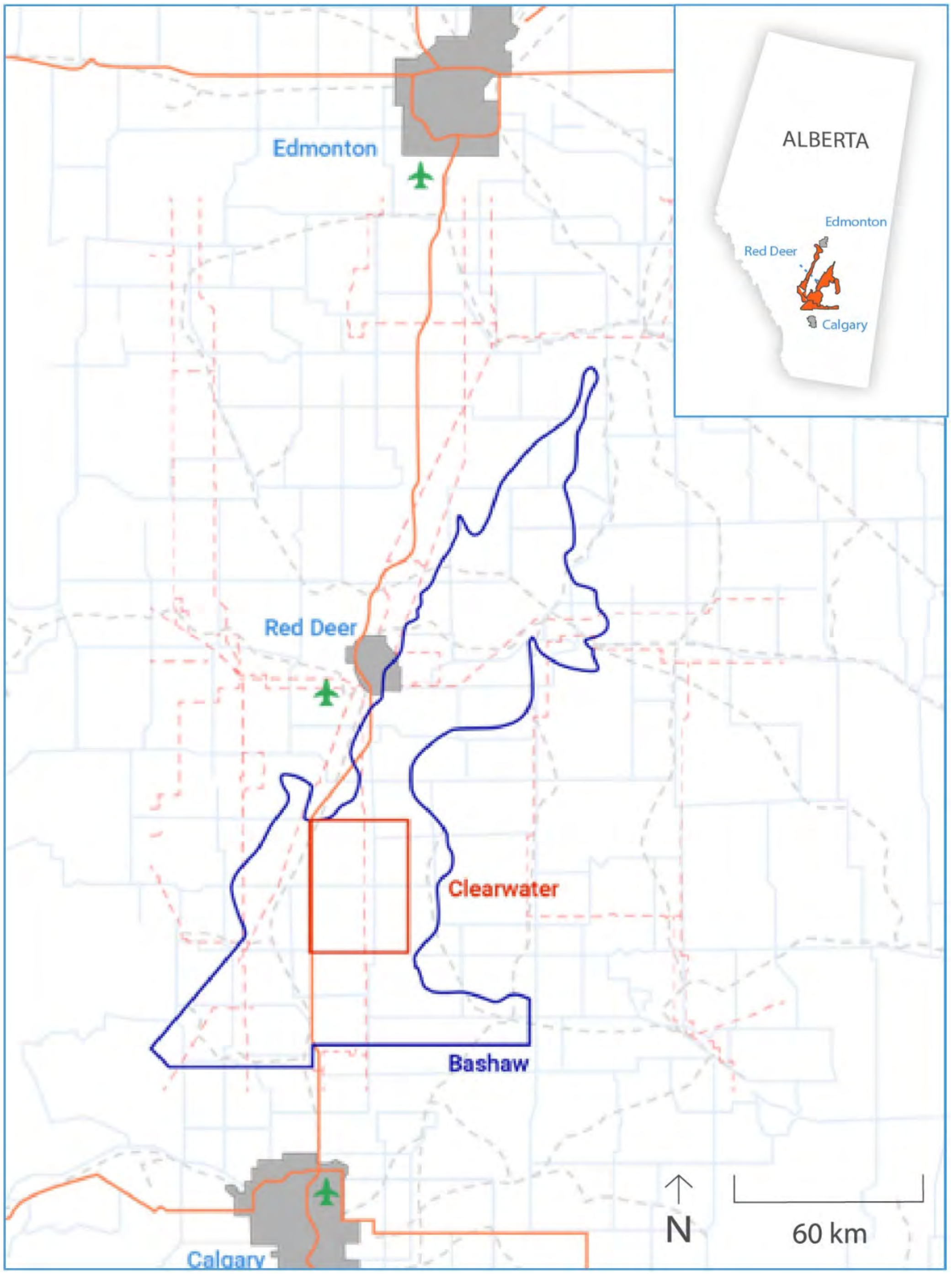
The Canadian Institute of Mining, Metallurgy and Petroleum (CIM) Definition Standards for Mineral Resources and Mineral Reserves (May 2014; the 2014 CIM Definition Standards), incorporated by reference into National Instrument NI 43-101 (NI 43-101) does not currently include brines as part of the "mineral" (2014 CIM Definition Standards) or "mineral project" (NI 43-101) definitions. However, there is a general acceptance within the industry that reporting brine projects as mineral projects is appropriate, and a brine-specific guideline exists (2012 CIM Best Practice Guidelines for Resource and Reserve Estimation for Lithium Brines). For the purposes of this Report, the estimates are referred to as Brine Resources or Brine Reserves, with the exception of statutory Item headings.

2.3 Report Terms

The Report uses the following terms:

- Bashaw District Mineral Property: referred to as the Bashaw District;
- Clearwater Project: also referred to as the Project; a rectangular area within the Bashaw District, which includes the drainage area, the infrastructure associated with the drainage area, and the Central Processing Facility;

Figure 2-1: Project Location Plan



Note: Figure prepared by E3, 2024.

- The Central Processing Facility: the infrastructure required for processing produced brine into saleable product.

The locations of the key areas in the bullet points above are shown on Figure 2-2.

Brine Resources and Brine Reserves are reported in accordance with the Canadian Institute of Mining, Metallurgy and Petroleum (CIM) Definition Standards for Mineral Resources and Mineral Reserves (May 2014; the 2014 CIM Definition Standards). Brine Resources and Brine Reserves were estimated using the 2019 CIM Estimation of Mineral Resources and Mineral Reserves, Best Practice Guidelines (2019 CIM Guideline) and the 2012 CIM Best Practice Guidelines for Resource and Reserve Estimation for Lithium Brines (2012 CIM Guideline).

The Report uses Canadian English. Monetary units are reported in Canadian dollars (C$) unless otherwise noted. Units are metric units unless otherwise noted.

The Report uses reservoir engineering terminology for most parameters rather than hydrogeological terminology to align with the proposed recovery method via existing oilfield technologies (wells, pumps, and pipelines) to extract the lithium-rich brine from the reservoir and supply it to a process facility that will use a direct lithium extraction technology. In some cases, however, hydrogeological terms can be used. A summary of key terminology is provided in Table 2-1.

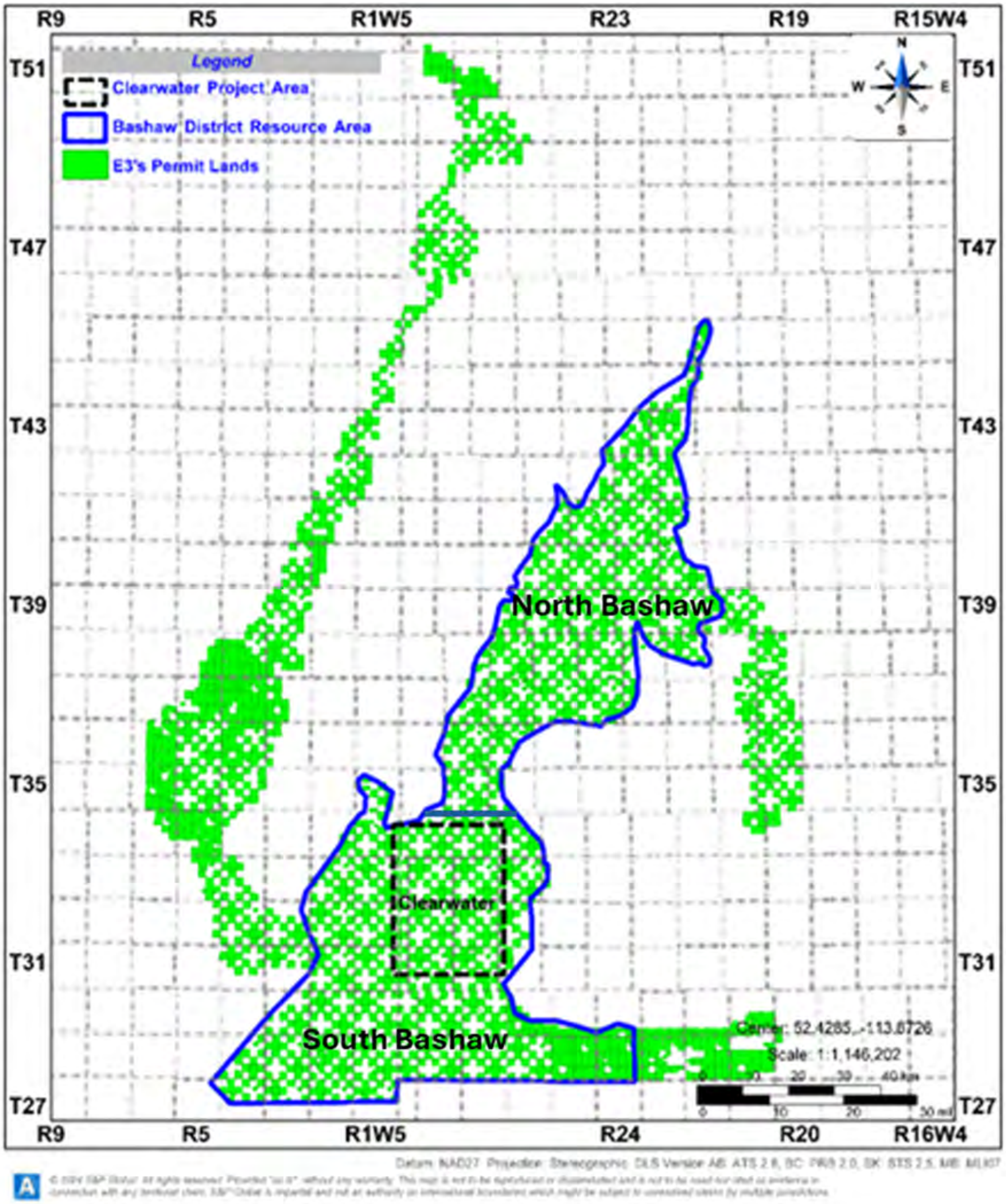
E3 adapted the standard oilfield approach for evaluating data distribution and variance which involves calculating "P10," "P50," and "P90" values. These metrics represent the 10^{th}, 50^{th}, and 90^{th} percentile values in a given data distribution. The 50^{th} percentile value (P50) represents a median and is not a mean value but these terms are equal for normal data distributions. Average (mean) values are presented in some sections of the Report where appropriate and are described as such.

2.4 Qualified Persons

The following serve as the qualified persons (QPs) for this Technical Report as defined in National Instrument 43-101, Standards of Disclosure for Mineral Projects, and in compliance with Form 43-101F1:

- Mr. Daron Abbey, M. Sc., P.Geo, Principal Hydrogeologist, Matrix Solutions Inc.;
- Mr. Alex Haluszka, M. Sc., P.Geo, Principal Hydrogeologist, Matrix Solutions Inc.;
- Ms. Meghan Klein, P. Eng., Senior Manager, Engineering, Sproule Associates Limited;
- Mr. Antoine Lefaivre, P.Eng., Lead Process Engineer, Sedgman Canada Ltd.;
- Mr. Keith Wilson, P. Eng., Principal Mining Engineer, Stantec Consulting Inc.

Figure 2-2: Key Area Location Plan



Note: Figure prepared by E3, 2024.

Table 2-1: Reservoir Engineering versus Hydrogeology Terminology

<table>
<tr><th>Reservoir Term(s)</th><th colspan="2">Equivalent Hydrogeological Term</th></tr>
<tr><td>Reservoir; net pay</td><td>Aquifer</td><td rowspan="2">Hydrostratigraphic units</td></tr>
<tr><td>Seal</td><td>Aquitard</td></tr>
<tr><td>Producible volume*</td><td colspan="2">Specific yield*</td></tr>
<tr><td>Total system compressibility product</td><td colspan="2">Specific storage</td></tr>
<tr><td>Irreducible water saturation</td><td colspan="2">Specific retention</td></tr>
<tr><td>Fluid mobility</td><td colspan="2">Hydraulic conductivity</td></tr>
<tr><td>Viscosity-corrected permeability thickness</td><td colspan="2">Transmissivity</td></tr>
<tr><td>Flow test</td><td colspan="2">Pumping test</td></tr>
<tr><td>Build-up; shut-in period</td><td colspan="2">Pumping test recovery period</td></tr>
<tr><td>Fall-off</td><td colspan="2">Injection test recovery period</td></tr>
</table>

Note: * Producible volume relies on reservoir drive mechanisms whereas specific yield assumes gravity drainage.

2.5 Site Visits and Scope of Personal Inspection

Mr. Haluszka visited the site on April 28, and September 15, 2022. During the April visit, he validated E3's sampling protocols. During the September site visit, Mr. Haluszka witnessed and validated a production test on an E3-operated well.

2.6 Effective Dates

The Report has the following effective dates:

- Date of the database close-out used for brine estimation: June 20, 2024;
- Date of the Brine Resource estimate: June 20, 2024;
- Date of the Brine Reserve estimate: June 20, 2024;
- Date of the economic analysis that supports the Brine Reserve estimate: June 20, 2024.

The overall Report effective date is the date of the Brine Reserve estimate and supporting economic analysis, and is June 20, 2024.

2.7 Information Sources and References

Reports and documents listed in Section 27 of this Report were used to support preparation of the Report. Additional information was provided by E3 personnel as required.

2.8 Previous Technical Reports

E3 has previously filed the following technical report on the Project:

- MacMillan, G., Williams, D.B., Pattinson, S., Vorster, W., and Owen, G., 2020: E3 Metals Corp., NI 43-101 Technical Report, Preliminary Economic Assessment, Clearwater Lithium Project, Alberta, Canada: technical report prepared by for E3 Metals Corp., effective date November 16, 2020, amended September 17, 2021.

3.0 RELIANCE ON OTHER EXPERTS

3.1 Introduction

The QPs have relied upon the following other expert reports, which provided information on mineral tenure, taxation and marketing assumptions.

3.2 Mineral Tenure, Surface Rights, Royalties and Agreements

The QPs have not reviewed the mineral tenure, nor independently verified the legal status, ownership of the Project area or underlying property agreements. The QPs refer to and fully rely upon, and disclaim responsibility for, information supplied by E3 experts and experts retained by E3 for this information through the following document:

- E3, 2024: RE: Clearwater Project within the Bashaw District Mineral Property: letter prepared for Ms. Meghan Klein, Mr. Daron Abbey, and Mr. Alex Haluszka, dated June 20, 2024, 6 p.

This information is used in Section 4 of the Report, and in support of the Mineral Resource estimate in Section 14, the Mineral Reserve estimate in Section 15, and the economic analysis in Section 22.

3.3 Taxation

The QPs have not independently reviewed the Project taxation position. The QPs have fully relied upon, and disclaim responsibility for, experts retained by E3 in the following report:

- E3, 2023: Taxation Support for Use in the Technical Report: letter prepared by E3 for Ms. Meghan Klein dated June 20, 2024, 1 p.

This information is used in Section 22 of the Report and support of the Mineral Reserves in Section 15.

3.4 Markets and Contracts

The QPs have relied on marketing experts retained by E3 for information relating to treatment and refining charges, metal pricing, and concentrate marketability through the following report:

- Benchmark Minerals Intelligence, 2024: Lithium Forecast, Q1 2024: powerpoint slide deck dated April 9, 2024, 65 slides;

- Fastmarkets, 2024: Independent Strategic Pre-feasibility Market Study on Global Lithium Markets: report dated June 6, 2024.

This information is used in Sections 19 and 22 of the Report and support the Mineral Resource estimate in Section 14 and the Mineral Reserves estimate in Section 15.

Metals marketing, global concentrate market terms and conditions, and metals forecasting are specialized businesses requiring knowledge of supply and demand, economic activity and other factors that are highly specialized and require an extensive database that is outside of the purview of a QP.

The QPs consider it reasonable to rely on Benchmark Minerals Intelligence, because the firm specialises in assessing market prices, supply chain data, forecasting and strategic advisory for the technologies and supply chains central to the energy transition. Benchmark Minerals Intelligence sets the industry's benchmark and reference pricing for lithium, nickel, cobalt, synthetic graphite, natural graphite, anodes, cathodes and lithium ion batteries, using a combination of data and industry knowledge. The company is considered to be an industry standard for lithium and critical mineral prices, data and supply chain intelligence used in major contract negotiations, infrastructure investment and government policy decision making.

Benchmark Minerals Intelligence's Forecast services provide a long-term outlook on the entire lithium-ion battery ecosystem, from the upstream raw materials, to the midstream products, to the final batteries, together with recycling insights. Each Forecast service provides an in-depth, long-term view on the major trends in each market sector and their implications, updated on a quarterly basis. The QPs consider the information from Benchmark Minerals Intelligence is suitable for use in the Report.

The QPs consider it reasonable to rely on Fastmarkets, because the firm is a cross-commodity price reporting agency in the agriculture, forest products, metals and mining, and new generation energy markets. Fastmarkets provides in-depth price data and short- and long-term forecasting and analysis for a range of battery metals. The company aims to collect data from a broad sample of market participants involved in physical commodities markets, with a good representation of both sides of the market, including producers and consumers, as well as traders and intermediaries. Fastmarkets' rationale for adopting a price-discovery process is to produce consistent and representative indicators of value for the markets that the company covers during defined trading periods. The QPs consider the information from Fastmarkets is suitable for use in the Report, as the company has a 50-year history of lithium market research and price forecasting.

E3 reviewed marketing and metal price forecasts used by industry peers in technical reports filed on SEDAR in the previous 12 months as an independent check on the information relied upon from Benchmark Minerals Intelligence and Fastmarkets, and discussed this information with the QP.

4.0 PROPERTY DESCRIPTION AND LOCATION

4.1 Introduction

The Clearwater Project is located within E3's Bashaw District brine-hosted minerals licence area in south–central Alberta, between the cities of Red Deer (about 50 km to the north of the Project) and Calgary (approximately 90 km south of the Project) (Figure 4-1). The Clearwater Project area overlies the carbonate reef complex deposits of the Leduc Formation, a hydrocarbon producer and reservoir for lithium brines.

The Bashaw District location is centered at approximately N52 6' 27.7; W113 43' 43.8".

4.2 Project Ownership

The Bashaw District is held by 1975293 Alberta Ltd., a wholly owned E3 subsidiary.

4.3 Mineral Tenure

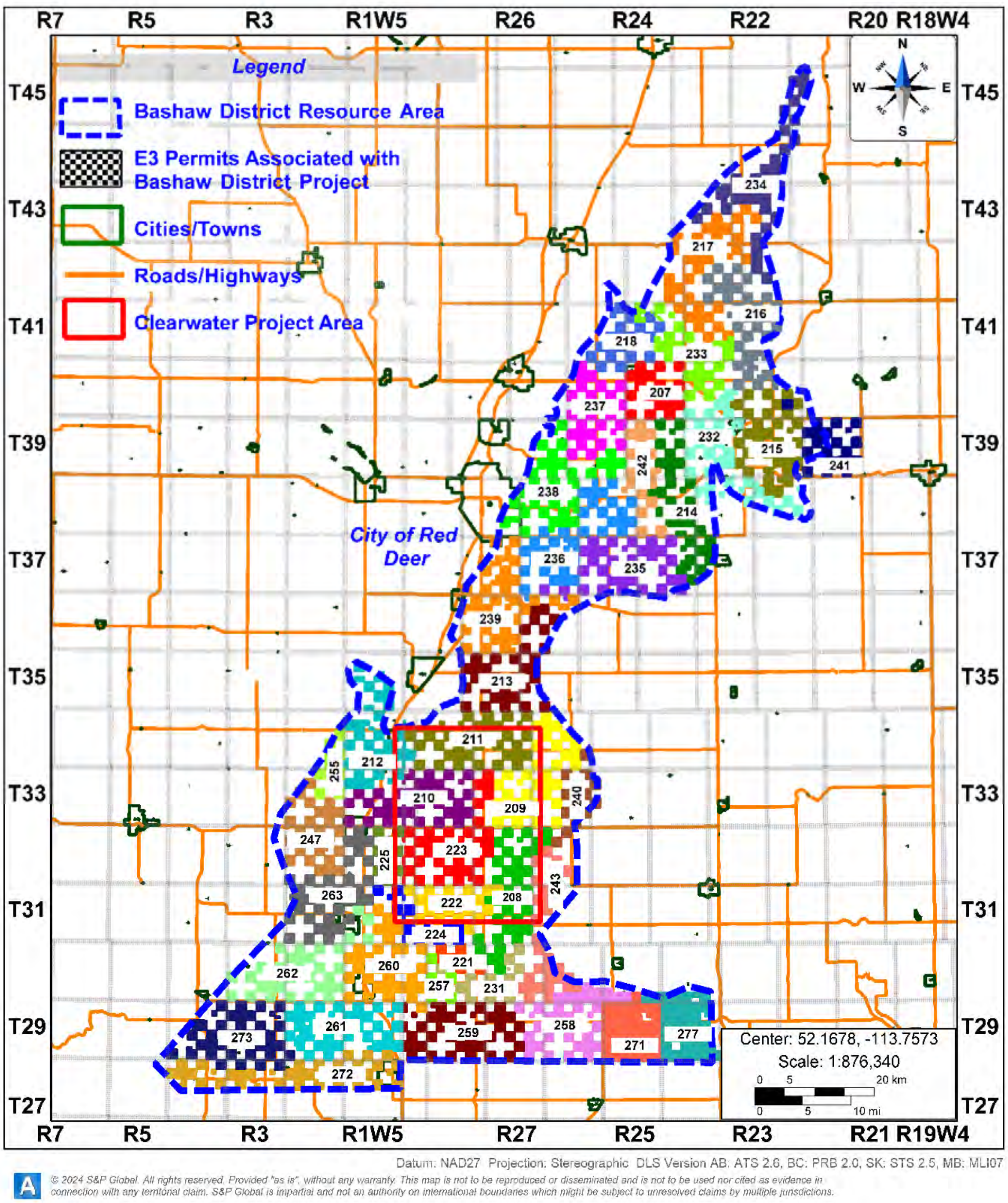
The Bashaw District consists of 46 brine-hosted minerals licences (207–218 inclusive, 221-–225 inclusive, 231–243 inclusive, 247, 255, 257–263 inclusive, 271–273 inclusive, and 277) that overlie the Leduc Formation in Southern Alberta (Figure 4-1).

The Clearwater Project within the Bashaw District covers an area of 77,872 ha, and contains all or portions of 10 brine hosted minerals licences (208–212 inclusive, 222–225 inclusive, and 243) within the Bashaw District (refer to Figure 4-1).

E3 first staked some of its permit tenure for Alberta Metallic and Industrial Mineral Permits in 2016, and continued with staking for permits until 2022. The Alberta Metallic and Industrial Mineral Permits granted the explorer the exclusive right to explore for metallic and industrial minerals for seven consecutive two-year terms (total of 14 years), subject to traditional biannual assessment work on Crown Land.

Amendments to the Metallic Industrial Minerals Tenure legislation came into force on January 1, 2023 (Alberta Energy, Energy Operations Division, 2022), which split the Metallic Industrial Minerals permits into rock-hosted metallic and industrials minerals permits, and brine-hosted minerals leases. From January 1, 2023 all metallic and industrial minerals permits were converted to rock-hosted minerals permits.

Figure 4-1: Permits Associated with the Bashaw District Project, Alberta, Canada



Note: Figure prepared by E3, 2024.

Active permit holders had the exclusive right to apply to convert the new rock-hosted minerals permits into brine-hosted minerals licences by December 31, 2023 (Alberta Energy, Energy Operations Division, 2022). Brine-hosted minerals licences are in place to aid the transition of brine-hosted mineral rights into a separate tenure regime and were only issued to eligible rock hosted minerals permit holders. No other brine-hosted minerals licences will be issued.

As an eligible rock-hosted minerals permit holder, E3 applied on November 17, 2023 to convert the rock-hosted permits to brine-hosted minerals licences. E3 received 100% of the permits converted to brine-hosted licences on January 26, 2024. These licences have a non-renewable term of five years with an annual rental fee, after which E3 intends to convert the licences to brine-hosted mineral leases.

The mineral permits are interspersed with privately-owned (freehold) land, where the subsurface and/or minerals rights are owned by private individuals and/or companies and not the Crown. The freehold mineral rights do not pose an obstacle to brine assay and mineral processing test work within the mineral permits owned by E3, as E3 can take assays and perform testing over areas for which they own the permits, and extrapolate the data to cover the areas that do not include E3's permits. The reservoir itself is not confined to the E3 permits but spans the whole Bashaw District.

Since June 23, 2022, E3 has formed a partnership with Imperial Oil with the option to purchase a number of the freehold mineral rights in the area to fill in some gaps within permit area. In 2024, a number of additional freehold sections were added to the original agreement to further fill in gaps within the Bashaw District. E3 is confident that appropriate agreements with off-setting freehold mineral owners can be arranged, per Alberta Energy Regulator D56 7.7.12(e) (Alberta Energy Regulators, 2024). Discussions with freehold owners are currently underway. E3 is able to proceed with exploration and development activities under the common-law principle of The Rule of Capture, wherein an exploration company is allowed to extract resources (including brine) from underneath their leased lands, regardless of whether that brine migrated from adjacent unleased lands. The resource volumes in this Report includes all lands within the Bashaw District outline, including both Crown and freehold mineral rights.

4.4 Surface Rights

Surface rights are owned mainly by private landowners over the Bashaw District, and E3 currently leases three surface locations from private owners for their three well pads.

Land in the area is mainly used for agricultural purposes, and historically surface access has been granted throughout the area for the purposes of oil and gas drilling. It is also possible to acquire surface leases for the purposes of drilling brine production wells and injection wells, as well as for the construction of a central processing facility.

Drill pad locations will be leased from individual property owners for an annual fee and must be reclaimed when the terms of the surface lease have been fulfilled or terminated. For facilities, surface locations can either be purchased or leased under the same conditions, and it is required that they are also reclaimed when the facility is decommissioned or abandoned.

Regulatory requirements that relate to surface leasing and purchasing are found under the *Surface Rights Act* (Government of Alberta, 2022). Under the *Surface Rights Act*, the holder to the rights to mines and minerals has a right to access the surface in order to work those interests. However, the *Surface Rights Act* requires an operator to obtain the surface owner's consent prior to entering the surface. If consent cannot be negotiated, then to avoid the risk of sterilization, the resource company can apply to the surface rights board for a right of entry order, and the surface rights board/tribunal would decide how to resolve this issue and how the surface owner would be compensated.

The QP considers that there is reasonable support for the assumption that E3 will gain surface access as needed to support the project development.

4.5 Royalties and Encumbrances

E3 previously held a royalty (signed in 2016 and revised September 24, 2020) which included the following eight permits: 9316060174, 9316060175, 9316060176, 9316060177, 9316060178, 9316060179, 9320100056 and 931911015. The agreement outlined a perpetual royalty equal to 2.25% of the gross proceeds from all products that were mined or extracted from those permits. E3 had an option to purchase all or a portion of the royalty any time before September 30, 2022 for $800,000 for the entire 2.25% of the royalty. E3 purchased 100% of this royalty for the $800,000 on September 30, 2022.

There were no known existing non-government royalties over E3's permit areas at the Report effective date.

4.6 Agreements

Agreements are in place for E3's three existing well locations, in perpetuity for the life of the well. Agreements for surface infrastructure locations were under active negotiation at the Report effective date.

4.7 Environmental Considerations

Environmental considerations are discussed in Section 20.

E3 currently owns three wellbores in the Clearwater Project area. Upon application to license/transfer ownership of these wellbores a liability assessment was required to determine risks to public and the environment, and a security deposit was made to the Alberta Energy Regulator to ensure that all future liabilities would be covered.

As the owner/operator of these wellbores, E3 is responsible for maintaining the wellbores and will be required to abandon these wells and reclaim these sites as set out in Directive 20 (Alberta Energy Regulator, 2023), and Directive 90 (Alberta Energy Regulator, 2023) by the Alberta Energy Regulator, and section 137 of the Environmental Protection and Enhancement Act (EPEA) (Government of Alberta, 2013).

4.8 Permitting Considerations

Permitting considerations are discussed in Section 20.

4.9 Social Licence Considerations

Social licence considerations are discussed in Section 20.

4.10 Sustainability

E3 is committed to sustainable development that extends to all facets of the planned business. As part of this approach, E3 has commenced stakeholder engagement and community outreach, and the aim is to emphasize high standards in environmental stewardship, social engagement and economic benefits for all stakeholders. It is fundamentally important to E3 to engage with the communities in which it operates by communicating with stakeholders, building relationships and identifying opportunities that will mutually benefit all parties.

4.11 Significant Risk Factors

Overlapping carbon capture and sequestration permits have been granted across portions of the Bashaw District to allow the evaluation of the Leduc reservoir to determine its suitability for carbon capture and sequestration projects. E3 is working with the carbon capture and sequestration evaluation permit holders to resolve subsurface conflicts and has engaged with Alberta Energy and the Alberta Energy Regulator on this topic. As E3 holds the mineral tenure rights, and the carbon capture and sequestration permits are at an early stage (e.g. evaluation rather than development), the resource estimate is proceeding on the assumption that none of the brine-hosting pore space needs to be excluded to account for carbon capture and sequestration development. E3 is not aware of any planned or potentially planned carbon capture and sequestration projects in the Clearwater Project area.

4.12 QP Comments on Section 4

There are no other significant factors and risks known to the QP that may affect access, title, or the ability to perform work in the Clearwater Project area other than discussed in this Report.

5.0 ACCESSIBILITY, CLIMATE, LOCAL RESOURCES, INFRASTRUCTURE, AND PHYSIOGRAPHY

5.1 Accessibility

The Bashaw District is readily accessible by air and ground transportation (Figure 5-1).

The City of Red Deer (population of 100,844) is located at the junction of Alberta Provincial Highway 2 and Highway 11. Highway 2 is the main corridor between Edmonton and Calgary and runs north–south along the west boundary of the Clearwater Project area.

Major and secondary provincial highways, and all-weather roads developed to support oil/gas infrastructure, occur throughout the permit areas. Additional access is provided by secondary one- or two-lane all-weather roads, and numerous all weather and dry weather gravel roads. Grid roads run every mile throughout the Project area, providing access year-round, ensuring mineral test work and extraction is not limited to certain months of the year.

There are international airports in Calgary (YYC) and Edmonton (YEG). Red Deer hosts a regional airport (YQF).

Two rail lines (Canadian National and Canadian Pacific + Kansas City Southern) are present throughout the area and connect to the major centers of Edmonton and Calgary, which occur north and south of the Project area, and then connect to all of North America.

5.2 Climate

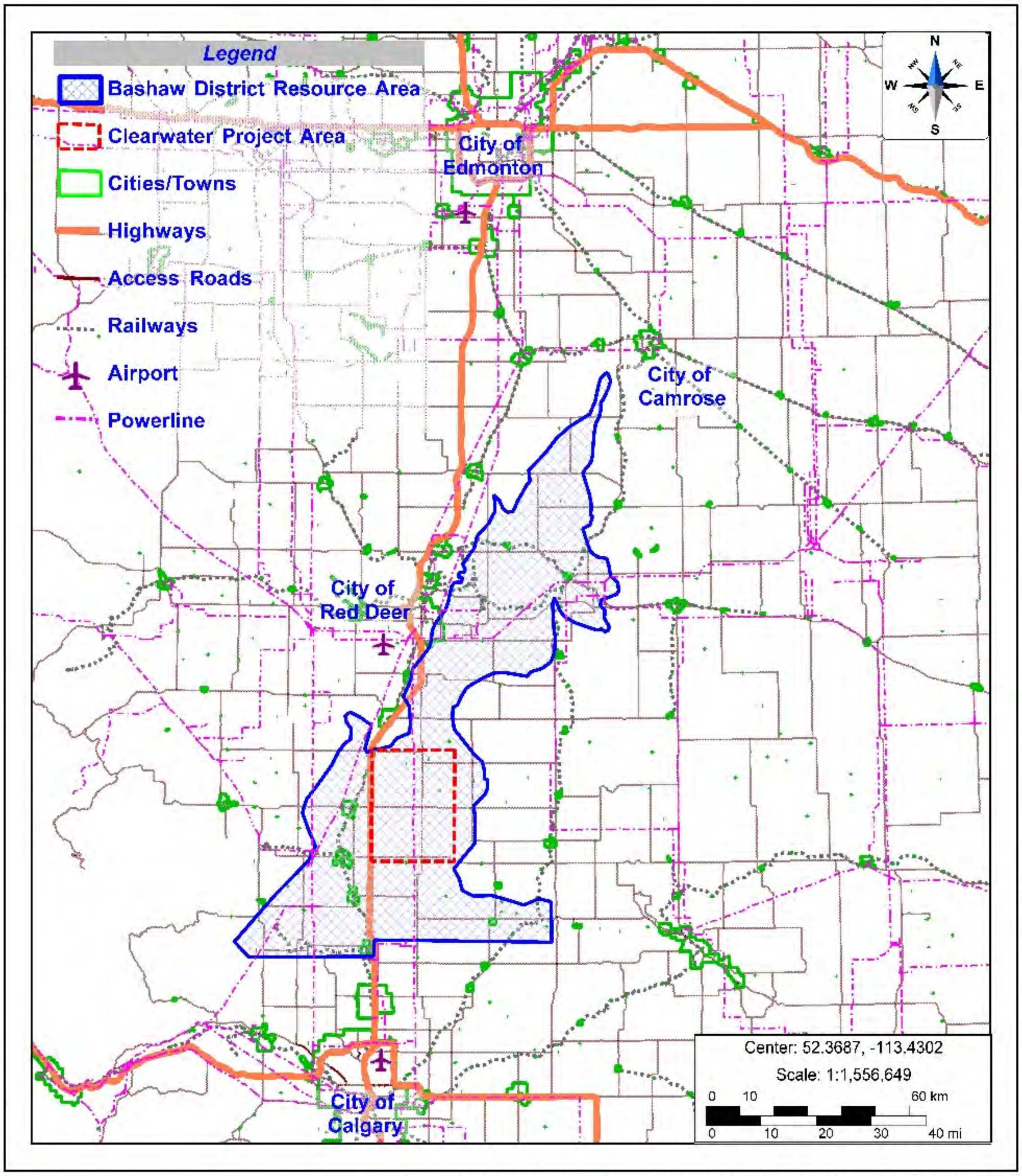
Calgary has a continental climate with severe winters, no dry season, warm summers and strong seasonality.

During summer, average daily high temperatures 23.2 °C and average daily low temperatures are 8.4°C). Winter temperatures have average daily highs of -2.1°C during the day and average daily lows of -13.3°C generally shortly after sunrise.

Total annual precipitation averages 395 mm.

Extraction operations will be conducted on a year-round basis. As this is a reservoir that will be produced using direct lithium extraction technology to extract lithium from brine, there are no climate related limitations to resource extraction, unlike the situation for salar-type deposits.

Figure 5-1: Infrastructure Access to Bashaw District



Datum: NAD27 Projection: Stereographic DLS Version AB: ATS 2.6, BC: PRB 2.0, SK: STS 2.5, MB: MLI07

Note Figure prepared by E3, 2024, after Government of Alberta - Ministry of Transportation, 2011.

5.3 Local Resources and Infrastructure

Accommodation, food, fuel, and supplies are readily obtained in the City of Red Deer (approximately 50 km from the Project) and the towns of Olds (about 20 km from the Project), Sylvan Lake (approximately 60 km from the Project) and Innisfail (about 30 km from the Project).

Internet and phone coverage are available throughout the permit areas.

Many trained workers live in the area and work in the oil and gas sector. These workers have the skills and expertise required to develop lithium from their related experience in oil and gas. Service companies, including those providing wireline services, testing, maintenance work, and drilling, all operate locally and will be capable of meeting the E3's needs relating to drilling, production and construction.

There is a significant amount of infrastructure in the area to support over 70 years of oil and gas development operations. Oil resources are typically produced in the area using pump jacks as the form of artificial lift. Hydrocarbons and water produced from the wells are delivered to separation facilities (either on site or at a satellite location) via underground pipelines. After separation, the various fluids and phases enter a network of pipelines designed for the transportation of gas, oil and water to specific destinations for upgrading, processing, to market, or for disposal. Pipelines specific to water are designed mainly to transport wastewater for subsurface disposal and/or injection purposes. These water pipeline networks are specifically located in areas developed for oil and gas.

Main highways are maintained and upgraded by municipal and provincial governments, and secondary gravel roads are well maintained. Grid electrical distribution and transmission infrastructure is available throughout the Bashaw District, and many of the locations sampled for the Brine Resource estimate have power accessible directly at the lease. There is adequate land in the area for process plants and related future infrastructure.

5.4 Physiography

The Bashaw District area lies within the Southern Alberta uplands and Western Alberta plains. The dominant landform is undulating glacial till plains, with about 30% as hummocky, rolling, and undulating uplands.

The average elevation is 750 masl, but ranges from 500 masl near the Alberta–Saskatchewan border to 1,250 masl near Calgary and 700 masl near Edmonton.

The Red Deer River is the dominant riparian feature, flowing south–southeast from the middle of the North Bashaw area within the Bashaw District to Drumheller in the in the southeast of the permit area.

The region is dominated by farmland with numerous creeks and wetlands occurring throughout the district.

Clusters of forested terrain consist predominantly of aspen, balsam poplar, lodge pole pine and white spruce. Vegetation in the wetland areas is characterized by black spruce, tamarack and mosses. Farmed areas commonly consist of prairie grasses.

5.5 QP Comments on Section 5

The QP notes:

- Extraction activities should be capable of being conducted year-round;
- There is sufficient suitable land available for extraction-related mine infrastructure within the mineral tenure holdings;
- Surface rights in relation to the proposed operation are discussed in Section 4.4.

6.0 HISTORY

6.1 Exploration History

E3's 2022 drill program was the first in Alberta specifically drilled to test brine for lithium concentrations. At the Report effective date, no other operator in Alberta had drilled wells solely to evaluate lithium concentrations in subsurface brines.

Historical testing of lithium in brine, prior to E3, was conducted as part of routine chemistry analysis by oil and gas operators in the area from produced water related to oil and gas production. These data were compiled in a comprehensive overview of the mineral potential of formation waters from across Alberta by the Government of Alberta (Hitchon et al., 1993; Hitchon et al., 1995). Subsequent collection of brine water from actively producing oil and gas wells was conducted by the AGS by Eccles and Jean (2010) and later by Huff (2016) and was analyzed for lithium.

A summary of the petroleum exploration and production and the lithium brine-related geological data sourced from the petroleum industry are summarized in the following sub-sections.

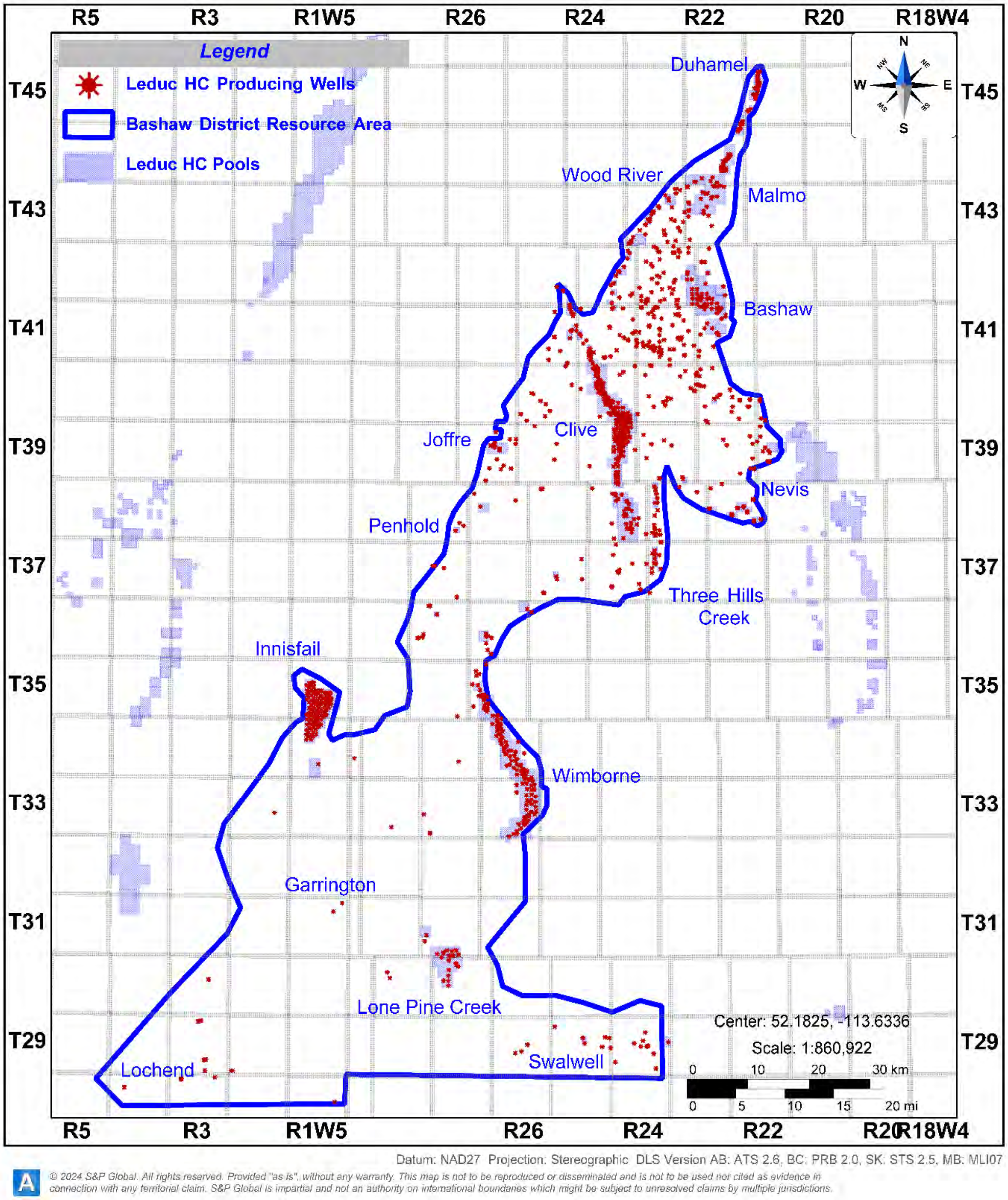
6.1.1 Brine and Hydrocarbon Drilling History

E3 drilled two vertical wells in June and July of 2022 and acquired a third deviated well through another operator (refer to discussion in Section 10).

The Leduc #1 well, drilled by Imperial Oil, was one of the first oil wells in Alberta drilled into Late Devonian strata in 1947. Some of the highest production rates and volumes historically come from Devonian-aged formations; this includes the Beaverhill Lake Group and the Swan Hills, Leduc, Nisku, and Wabamun Formations. The Leduc Formation reefs were a prevalent target for hydrocarbons from the mid to late 20^{th} century due to their size and very high porosity and permeability. Currently there is resurgence in drilling activity in the Devonian with the improvement of technology allowing for the development of lower permeability unconventional oil reservoirs such as the Duvernay Formation. A significant volume of hydrocarbons has been produced from the Devonian as well as from some of the younger zones above in the Mississippian and Cretaceous. It is the Leduc Formation that is of significance with respect to this assessment for mineral brine potential in the Bashaw District.

The Bashaw District contains several Leduc oil pools of note, such as the Clive, Bashaw, Nevis, Three Hills Creek, Wimborne, Wood River, Garrington, Innisfail, Lone Pine Creek, Joffre, Swalwell, Lochend, Penhold, Duhamel and Malmo pools (Figure 6-1).

Figure 6-1: Location of Leduc Wells and Pools in the Bashaw District



Note: Figure prepared by E3, 2024.

A query of public data using Accumap software (S&P Global) shows total of 13,729 wells have been drilled within the Bashaw District dating back to 1947, targeting the former mentioned pools and as exploratory wells delineating hydrocarbon potential. Of these wells, 2,398 have intercepted the Leduc Formation. The Innisfail oil field, along the western edge of the Bashaw District, was discovered in 1956 by Canadian Oils Ltd., and the Wimborne field along the eastern edge of the Bashaw District, was discovered by Seaboard Oil Company in 1954. The Duhamel oil field on the northern edge of the Bashaw District was discovered in 1950 by Socony Vacuum Exploration Co., and the Swalwell field and the town of Crossfield define the southern edge of the Bashaw District. The Swalwell was discovered in 1953 by Canadian Delhi Oil LTD. An Accumap (S&P Global software) total of 1,579 wells are classified as having produced, currently producing or injecting into the Leduc Formation.

6.1.2 Core Data and Historical Well Logs

Open hole wireline logging technology is an effective method for evaluating reservoir properties. Wireline logs (also called well logs) are a standard tool employed by the petroleum industry when drilling for and developing oil and gas pools. They provide physics-derived information about rock properties and fluid dynamics in the subsurface. This information is used to interpret the depths, lithology and fluid composition of subsurface rock formations.

A rich database of well log information exists in the area due to oil and gas development dating back to the 1950s, and this well log data can be leveraged for the purposes of brine-hosted lithium exploration. Wireline tool technology has advanced considerably over the last few decades, and data resolution and quality tended to improve significantly after the 1980s. Due to the variety of well vintage and depth, a wide range of type and quality of well log data exists.

The well logs available in the area are as follows:

- Gamma ray logs: measures the radioactivity of rocks and helps determine lithology (PetroWiki SPE, 2015);
- Induction logs: measure formation electrical conductivity, and helps determine lithology and fluid composition (PetroWiki SPE, 2017);
- Density and neutron logs: measure hydrogen concentration and electron density (PetroWiki SPE, 2015), and helps determine lithology and pore space in the rock;
- Photoelectric logs: measure atomic weight of the rocks, and helps determine lithology

Core analysis is also routinely completed by the oil and gas industry. Standard oil and gas core analysis includes measurements of porosity and permeability. Various approaches can be taken to make these measurements (American Petroleum Institute, 1998). Typically, the porosity is determined by weighing the sample, then cleaning the sample and completely flushing all the liquid out of it. The sample is then dried in an oven and weighed again. Then either air or helium is used to measure the pore volume and porosity is calculated based on the amount of total pore volume in the rock sample.

Permeability is also typically measured using air and is measured in two directions. One is the direction that has the maximum permeability (Kmax) and the second is measured at 90º to the maximum (K90).

Comparing core analysis with measurements obtained in petrophysical logs helps to validate whether the log data are reasonable. Publicly-available core analysis data are available for 329 wells within the Bashaw District. Distribution of the core analysis data is limited to existing hydrocarbon production wells that were drilled over the past 70 years, and is mainly limited to the upper portion of the Leduc reservoir where hydrocarbons have accumulated.

6.1.3 Hydrocarbon Industry Drill Stem Tests

A drill stem test is an oilfield test that isolates a particular range of depths in a wellbore to measure the reservoir pressure, permeability and fluid types present at specified depths. Drill stem tests have been run in the vicinity of the resource areas since the 1950s.

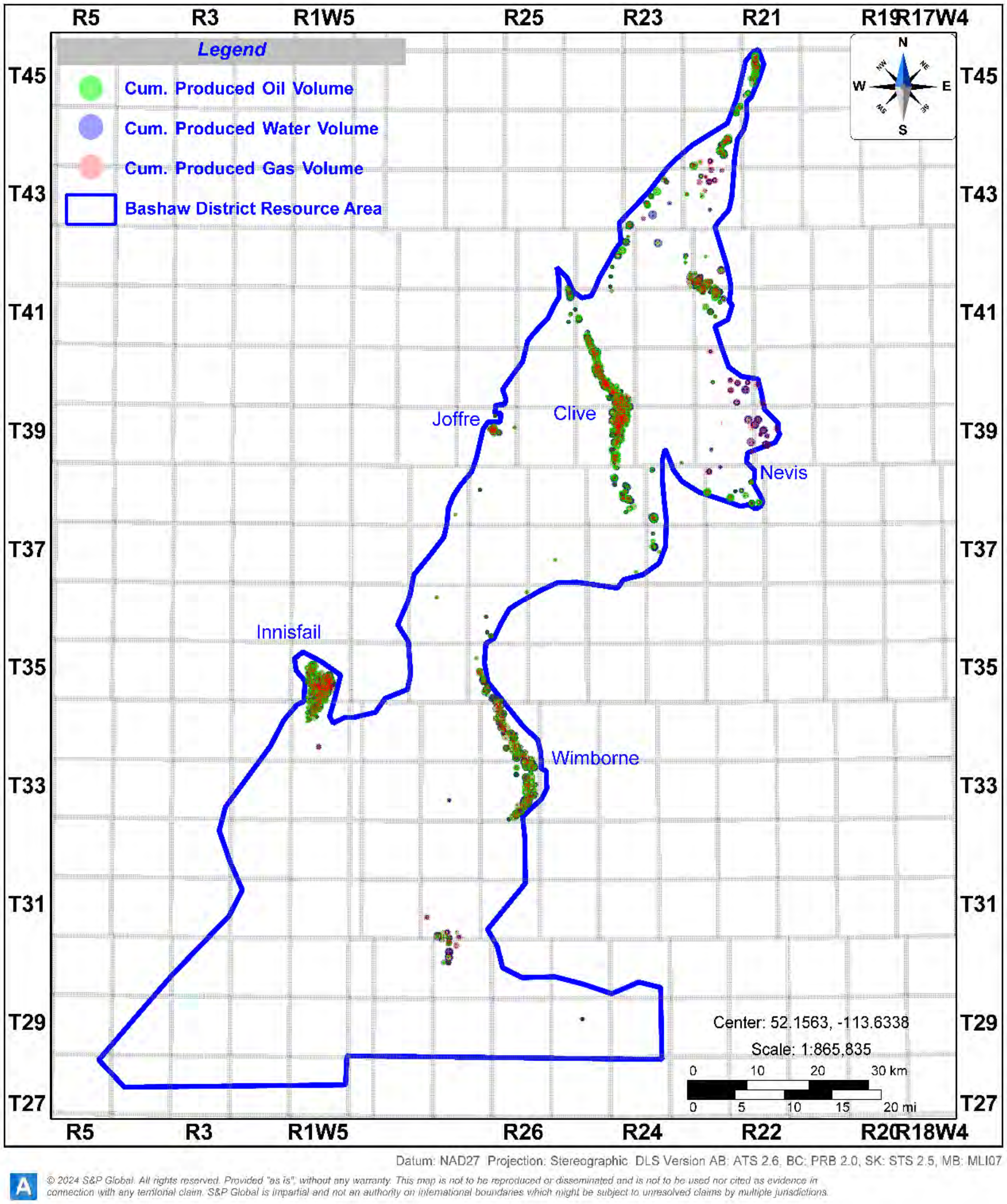
6.1.4 Existing Production, Injection, and Disposal

Historical production volumes for the Cooking Lake and Leduc Formations were exported from S&P Global's Accumap software. The reported production was queried for the Bashaw District, and a buffer area around the Bashaw District, to include production from outside of the Brine Resource estimate area that may directly affect pressures in the Bashaw District.

The Bashaw District historical production query included Townships 28 to 45 and Ranges 4W5M to 20W4M. A total of 593 production wells and 57 injection wells in the Bashaw District and buffer area, had at least one day of reported rates from the Leduc Formation, with no recorded data from the Cooking Lake Formation.

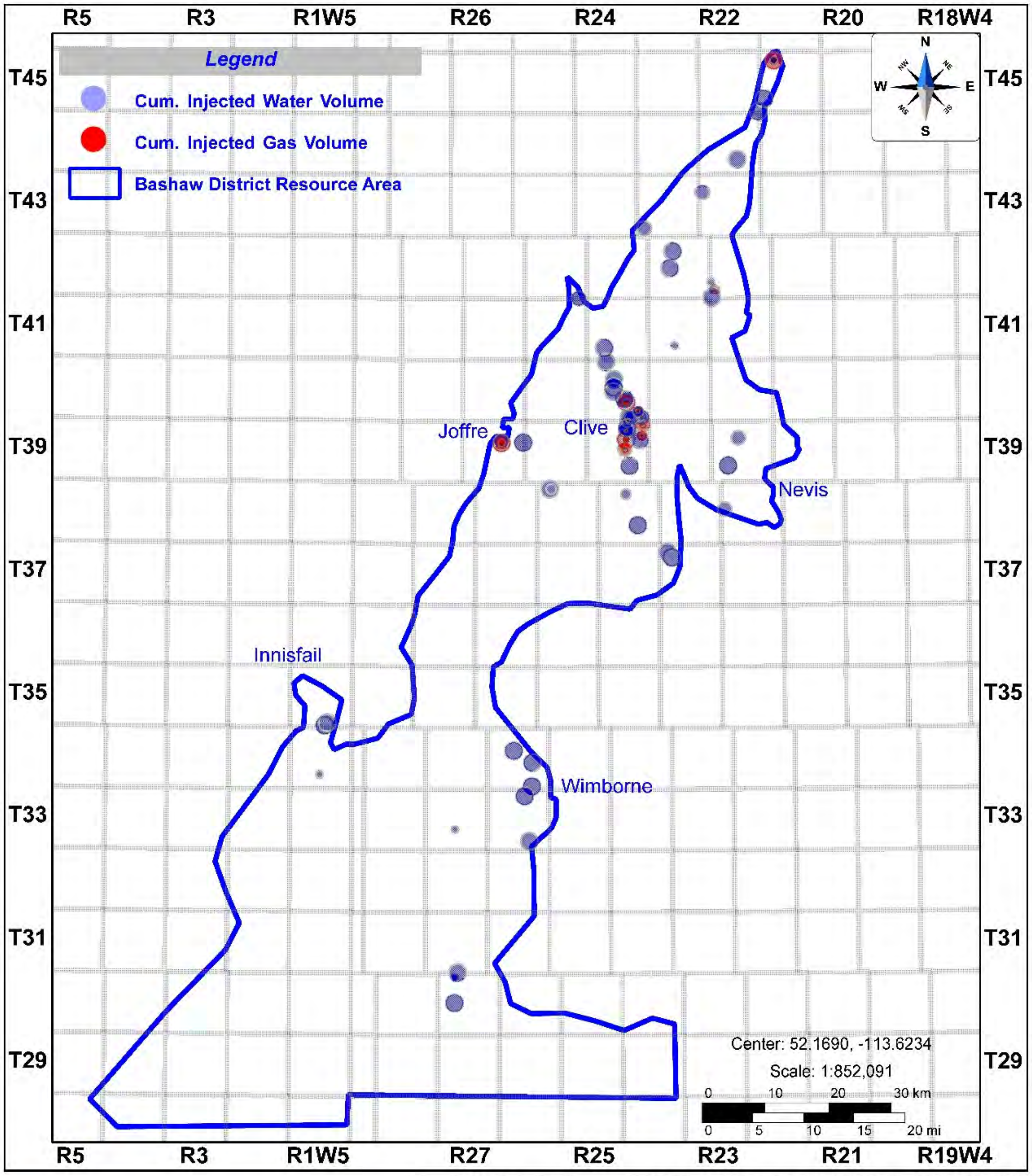
Within the Bashaw District, most of the liquid production is from the Innisfail, Wimborne, and Clive fields while most of the gas production is from the Nevis field (Figure 6-2). Most of the liquid injection is into the Wimborne, Innisfail, and Clive fields while most of the gas injection is in the Joffre and Clive fields (Figure 6-3). The first year of reported production was 1962 and the last month of production data summarized is October, 2023 (Figure 6-4; Table 6-1). There is currently no active production from the Leduc Formation within the Clearwater Project area.

Figure 6-2: Production by Fluid Type from the Leduc Formation in the Bashaw District



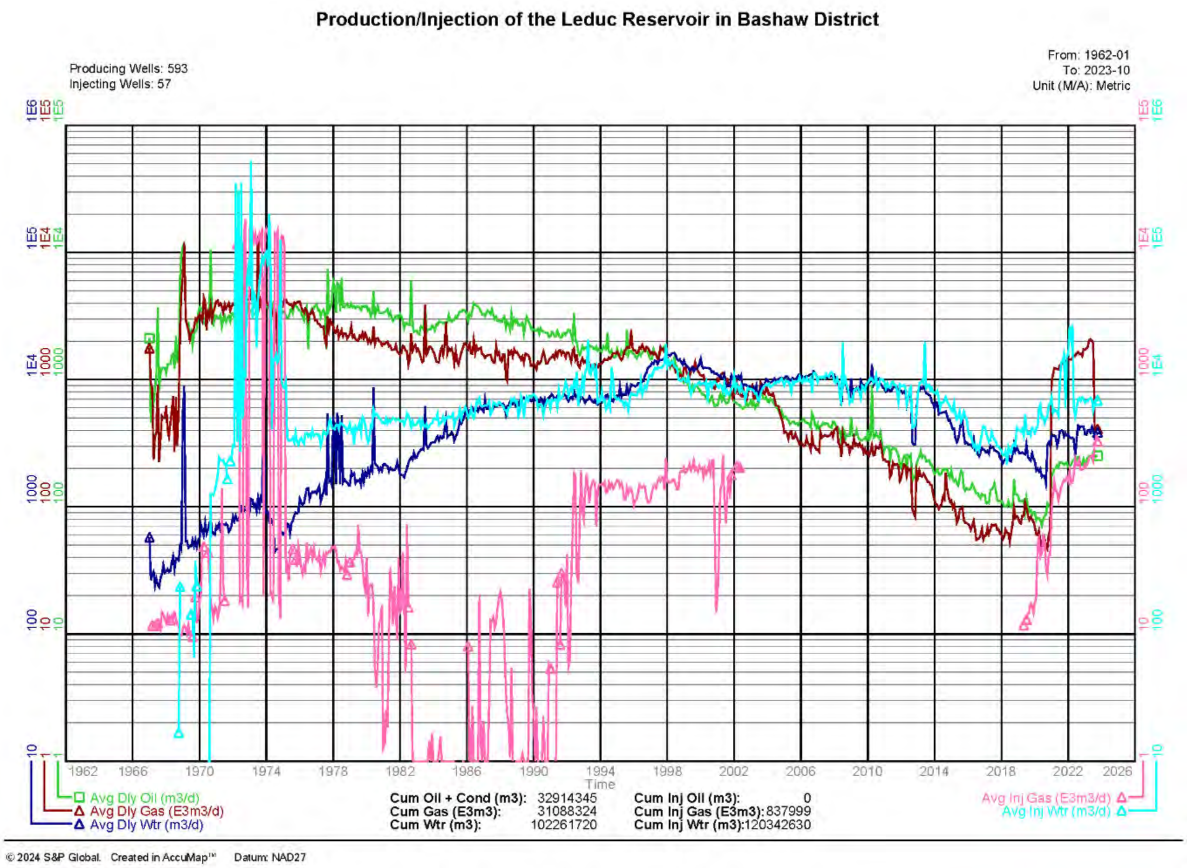
Note: Figure prepared by E3, 2024.

Figure 6-3: Cumulative Injection into the Leduc Formation in the Bashaw District



Note: Figure prepared by E3, 2024.

Figure 6-4: Production/Injection History of the Leduc reservoir in the Bashaw District



Note: Figure prepared by E3, 2024. Data sourced from Accumap, S&P Global, 2024.

Table 6-1: Cumulative Volumes in the Bashaw District

	Production (m^3)	Injection (m^3)
Gas	1,088,324,000	837,999,000
Oil + condensate	32,914,345	—
Water	102,261,720	120,342,630

Historical volumes of gas and oil produced peaked in the 1970s and has decreased considerably since then as hydrocarbons have been depleted. By contrast, water production as a by-product increased considerably since the 1970s and plateaued in the mid-1990s and remained steady for about 25 years. The Leduc Formation has sustained production and injection rates of ~1,000 m^3/d for about 15 years.

Peak rates reported across the Bashaw District are 2,618 m^3/d for injection (100/06-02-034-26W4/00) and 2,569 m^3/d for production (100/13-05-041-24W4/00). Using hydrocarbon production and injection data to show producibility/injectivity of the Leduc reservoir helps to validate that the Leduc reservoir has reasonable prospects for eventual economic extraction of lithium brine using production wells. The long and sustained production history from the hydrocarbon window with a considerable amount of accompanying water shows that water can be pumped to surface for use with direct lithium extraction technology and re-injected back to where it was produced from.

6.1.5 Historical and Publicly Available Lithium Data

The first comprehensive overview of the mineral potential of formation waters from across Alberta was compiled by the Government of Alberta (Hitchon et al., 1993, 1995).

'Formation water' is used as a generic term to describe all water that naturally occurs in pores of a rock. Formation water is currently being produced as a waste by-product associated with petroleum and natural gas from existing wells. Pressure loss in the reservoir is being mitigated through re-injection of fluid from produced wells and possibly has included waters from other pools and other zones, as well as fresh water.

Hitchon et al., (1993, 1995) compiled nearly 130,000 analyses of formation water from various stratigraphic ages across Alberta. The data were derived from numerous sources including Alberta Energy Regulator submissions for drilling conducted by the petroleum industry and various Government of Alberta reports (e.g., Hitchon et al., 1971; Dunham, 1962) (Figure 6-5).

The method for defining geographic areas with elements of possible economic interest in formation water was defined by Hitchon (1984) and Hitchon et al. (1995). For each element studied (e.g., calcium, magnesium, potassium, lithium, bromine and iodine), a 'detailed exploration threshold value' was determined by studying the concentrations in economically producing fields as defined in Hitchon (1984) and Hitchon et al. (1995). Additionally, a lower 'regional exploration threshold value' was defined to allow for contouring and extrapolation of data to undrilled areas. For example, the regional exploration threshold value for lithium was considered to be 50 ppm and the detailed exploration threshold value was defined as 75 ppm lithium (Hitchon et al. (1995)).

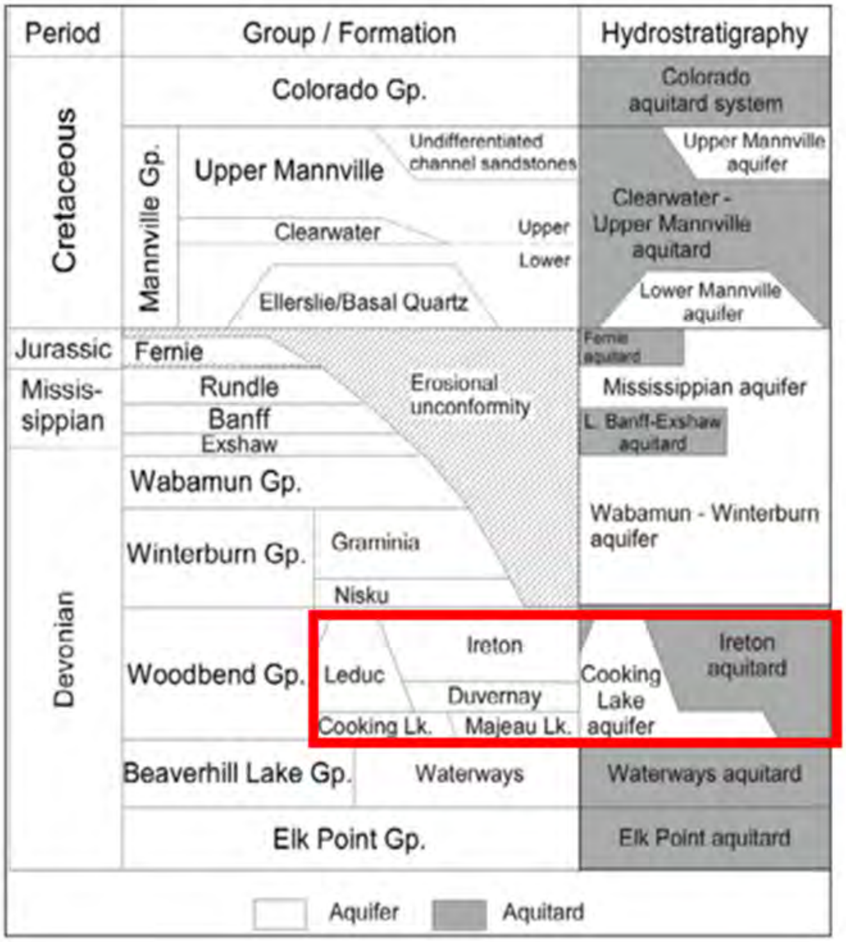
At the provincial scale, Hitchon et al. (1995) showed that lithium was analyzed and reported in 708 formation water analyses (out of the 130,000 total analyses examined). Of the 708 analyses, 96 analyses yielded lithium concentrations above the 'regional threshold value' (>50 ppm); and 47 analyses yielded lithium concentrations above the 'detailed threshold value' of 75 ppm. Significantly, Hitchon et al. (1993, 1995) showed the highest concentrations of lithium in formation water (as much as 140 mg/L Li) occurred within Middle to Late Devonian reservoirs associated with the Beaverhill Lake Group (Swan Hills Formation), Woodbend Group (Leduc Formation), Winterburn Group (Nisku Formation) and Wabamun Formation.

More recently, Eccles and Jean (2010) modelled 1,511 lithium-bearing formation water analyses from throughout Alberta; this compilation supported the conclusions in Hitchon et al. (1995) that brines associated with Devonian strata contain elevated concentrations of lithium in reef systems throughout Alberta. Of the 1,511 analyses, 19 analyses/wells contained >100 mg/L Li (maximum value of 140 mg/L), all of which were sampled from within the Middle to Late Devonian carbonate complexes.

In 2022 the Alberta Geological Survey collected 249 produced water samples from oil and gas wells across Alberta, where dissolved lithium concentrations were measured. These results are now publicly available on the Alberta Geological Survey website.

From this historical reported dataset, 19 samples were taken from the Bashaw District, from the Winterburn Group (Nisku Formation) and Woodbend Group (Leduc Formation). The lithium concentrations ranged from 60–135 mg/L and had a mean of 77 mg/L. E3 was unable to return to these exact locations for resampling because the wells have since been suspended or abandoned. Therefore, these historical data were not explicitly used in the Brine Resource estimate but were used to inform E3's understanding the continuity of lithium grade in the Leduc reservoir.

Figure 6-5: General Stratigraphy and Hydrostratigraphy of Alberta, Bashaw District Highlighted



Note: Figure modified from Lawton and Sodgar, 2011.

6.2 Production

There has been no commercial lithium brine production from the Project area.

7.0 GEOLOGICAL SETTING AND MINERALIZATION

7.1 Regional Geology

The Bashaw District is situated in the southwestern part of the Western Canada Sedimentary Basin. In this area, the Upper Devonian (Frasnian) sediments of the Woodbend Group were deposited in a shallow tropical inland sea. The sea was bounded by the emergent Peace River Arch to the northwest and by the West Alberta Ridge to the southwest, creating a barrier between the sea and the open ancestral Pacific to the west (Potma et al., 2001).

7.2 Project Geology

A stratigraphic column for the Bashaw District was provided in Figure 6-5.

7.2.1 Precambrian Basement

The basement underlying the Bashaw District is predominantly comprised of Lacombe Domain rocks, with the southeastern portion of the property on the Hearn Terrane (Panǎ, 2003). The Hearn Terrane is part of the Churchill Province and formed approximately 2.6 to 2.8 billion years ago (Ross et al., 1991).

7.2.2 Phanerozoic Strata

A thick sequence of Paleocene and Cretaceous clastic rocks and Mississippian to Devonian carbonate, sandstone and salt overlie the basement (Greenet al., 1970; Glass, 1990; Mossop and Sheston, 1994). At the base of the Beaverhill Lake Group, the Elk Point Group comprises restricted marine carbonate and evaporite that gradationally overlies the Watt Mountain Formation (Mossop and Sheston, 1994). The Upper Elk Point, including the Ft. Vermillion, Muskeg and Watt Mountain formations represent a seal (Hitchon, 1990).

The Upper Devonian Woodbend Group conformably overlies the Beaverhill Lake Group. The Woodbend Group is dominated by basin siltstone, shale and carbonate of the Majeau Lake and Cooking Lake Formations. The Duvernay and Ireton Formations surround and cap the reef complexes of the Leduc Formation.

The Leduc reefs are characterized by multiple cycles of reef growth including backstepping reef complexes and isolated reefs (Mossop and Sheston, 1994).

The Duvernay Formation is composed of dark bituminous shale and limestone which contain and preserve a large accumulation of organic carbon thought to be the source for most of the conventional hydrocarbons in the upper Devonian in Alberta.

The Ireton Formation caps the Leduc reefs and was deposited through increased fine grained sedimentation into the region (Mossop and Sheston, 1994). The Ireton Formation is a seal that forms an impermeable cap rock over the Leduc reefs (Hitchon et al., 1995). The Camrose Member represents the only significant carbonate deposition during the Ireton cycles of basin-filling shale (Stoakes, 1980).

The Woodbend Group is conformably overlain by the Winterburn and Wabamun Groups of upper Devonian age. In the Bashaw District, the Winterburn thickness in south–central Alberta is available from the logs of holes drilled for petroleum and is composed of shale and argillaceous limestone. These two groups comprise the Wabamun–Winterburn reservoir system from which a few lithium concentration analyses have been obtained (Hitchonet al., 1995).

The Wabamun Group is composed of buff to brown massive limestone interbedded with finely crystalline dolomite at the base.

The Wabamun Group is unconformably overlain by the Lower Carboniferous Exshaw Shale. The Exshaw Shale is overlain by the Banff Group, which is composed of a medium to light olive grey limestone with subordinate fine-grained siliciclastic rocks, marlstone and dolostone overlying a basal shale, siltstone and sandstone unit (Mossop and Sheston, 1994).

The Rundle Group conformably overlies the Banff Group and is composed of cyclic dolostone and limestone with subordinate shale. Permian strata in the area are thin. The Permian Belloy Group unconformably overlies the Rundle Group and is unconformably overlain by the Triassic Montney Formation. It comprises shelf sand and carbonate (Mossop and Sheston, 1994).

The overlying Mesozoic strata (mainly Cretaceous) consist of alternating units of marine and nonmarine sandstone, shale, siltstone and mudstone. The Triassic strata include fine-grained argillaceous siltstone and sandstone. The overlying Jurassic Fernie Group consists of limestone of the Nordegg Formation that is overlain by interbedded sandstone, siltstone and shale (Mossop and Sheston, 1994). The Lower Cretaceous strata are represented by the Bullhead, Fort St. John and Shaftesbury Groups which comprise a major clastic wedge on the foreland basin.

The uppermost bedrock units underlying the Bashaw District include the late Cretaceous Horseshoe Canyon and Scollard Formations and Paleocene Paskapoo Formation. The Horseshoe Canyon Formation strata consist of interbedded sandstone, siltstone, mudstone, carbonaceous shale and coal seams. The Scollard Formation consists primarily of sandstone and siltstone that is interbedded with mudstone. Coal seams in the upper portion of the Scollard Formation are economically significant, particularly in western Alberta. Finally, the Paskapoo Formation marks the top of the stratigraphy across the Bashaw District, and much of southwestern Alberta. It consists of sandstone, siltstone and mudstone.

7.2.3 Quaternary Geology

During the Pleistocene, multiple southerly glacial advances of the Laurentide Ice Sheet across the region resulted in the deposition of ground moraine and associated sediments in south–central Alberta (Dufresne, et al., 1996).

The majority of the Bashaw District is covered by drift of variable thickness, ranging from a discontinuous veneer to just over 15 m (Pawlowicz, 1995a). Bedrock may be exposed locally, in areas of higher topographic relief or in river and stream cuts. The advance of glacial ice may have resulted in the erosion of the underlying substrate and modification of bedrock topography.

Limited general information regarding bedrock topography and drift thickness in south-central Alberta is available from the logs of holes drilled for petroleum, coal or groundwater exploration and from regional government (Alberta Geological Survey) research compilations (Mossop and Sheston, 1994; Pawlowicz, 1995a).

Glacial ice is believed to have receded from the area between 15,000 and 10,000 years ago.

7.2.4 Structural History

The Bashaw District permits are situated east of the Rocky Mountains and are not within the deformed area. An extensive study by Edwards et. al. (1998; 1999) using aeromagnetic data, gravity data, and lineament analysis indicates that deep-seated faulting related to the Precambrian basement and the Snowbird Tectonic Zone appear to have at least partial control on the distribution of reefs and some of the oil fields in the area.

Many of the Devonian reef complexes in the permit area are underlain by or are proximal to basement faults. This would imply that these deep-seated faults were active around the time of reef deposition.

7.3 Deposit Geology

7.3.1 Deposit Dimensions

The Bashaw District covers a portion of the Wimborne-Bashaw trend, comprising Townships 28 to 45 and Ranges 21 to 28 West of the 4th Meridian, to Range 5 West of the 5th, covering about 250 x 50 km (Figure 7-1).

The Clearwater Project area covers the portion of the Bashaw District in the south and spans Township 31 Range 26 west of the 4th meridian in the southeast corner and extends to Township 34, Range 1 West of the 5th Meridian in the northwest corner, covering an approximately 30 x 25 km area (Figure 7-1).

The lithium mineralization is approximately 200 m thick across both the Bashaw District and the Clearwater Project.

7.3.2 Data Sources

Data sources used to evaluate the geological setting and mineralization were primarily derived from historical, publicly-available oil and gas datasets. These datasets were evaluated for quality and are summarized in Table 7-1.

7.3.3 Data To Support Geological Interpretations

A total of 101 wells in and around the resource areas penetrate the full stratigraphic section of the Leduc reservoir and Cooking Lake platform. A total of 2,397 wells penetrate the top of the Leduc reservoir and were not drilled deep enough to intersect the lower Cooking Lake Formation. This is typical of wells drilled for the purpose of hydrocarbon production in the Leduc reservoir, specifically.

The edge of the Leduc carbonate complex is defined as the point at which the Leduc carbonate production factory transitions to basinal slope deposits (zero-edge). This edge differentiates the high porosity reefal buildups of the Leduc Formation from the surrounding low porosity carbonate muds and shales of the deep-water basin sediments occurring in the Ireton and Duvernay Formations. The zero-edge, the basis for the Bashaw District, was defined primarily using well data.

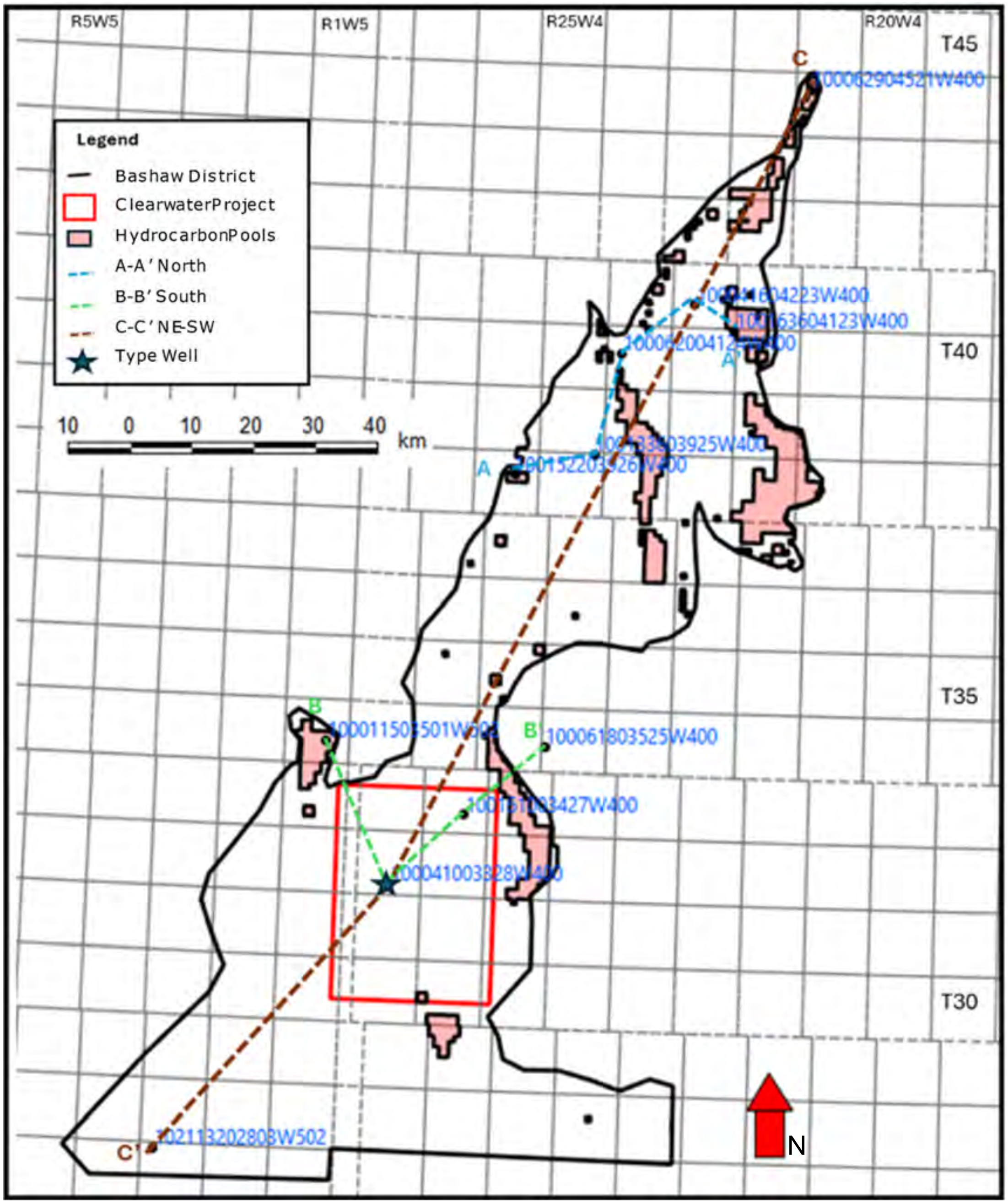
Table 7-1: Summary of Oil and Gas Relevant Data Sources

Data Type	QA/QC Criteria	Data Useage	Note
E3's 2022 flow test	Consistent flow rates monitored in the field during test and stable gas production Consistent pressure data collection (build-up, fall-off) Pressure derivative analysis	Pressure validation Brine analysis: lithium concentrations Permeability estimation Flow system continuity	
E3's 2022 evaluation well program	Sufficient depth Core recovery and quality Geophysical well log QA/QC (see below) Field monitored water chemistry parameters within specified thresholds	Core analysis: total and effective porosity; permeability measurements; facies descriptions Downhole wireline logs: lithology; total and effective porosity Brine analysis: lithium concentrations	
Well logs	Logging completed by registered oilfield logging company with standards of practice and QA/QC procedures	Geologic mapping (stratigraphic and structural) Formation thickness (isopach) Fluid contacts (oil/gas; oil/water)	Well logs penetrating through both the Leduc and the Cooking Lake formations were used to determine the top and bottom of the formations and, the lateral extent of the Leduc over top of the Cooking Lake Platform. After formation tops were selected, well logs were then used to determine fluid contacts (oil/gas, oil/water) and reservoir parameters within the Leduc. Neutron-density logs were used where available, as they are a more reliable log type. In an effort to leverage all available data, sonic logs were used where they were the only logs available. There are 2397 well logs in the Bashaw District which penetrate the Leduc reservoir, and 101 well logs that are drilled to the Cooking Lake platform (or deeper). Within this dataset, there are also 329 wells with core porosity and permeability measurements in the Leduc formation,

Data Type	QA/QC Criteria	Data Useage	Note
			and 57 wells where E3 completed enhanced petrophysical modeling to normalize the porosity curves in the wireline logs and correlate the curves to the core porosity.
Petrophysical analysis (57 wells)	Complete wireline data set	Porosity [total and effective] Permeability [vertical & horizontal] Fracture identification Evaporite identification Fluid saturations	A petrophysical model was generated using 57 Log ASCII Standard (Digitized Well Logs, 2023) curves over the Bashaw area. Linear regression analysis was used to derive permeability (outlined in Section 14) as it can identify hydraulic flow units and correlates well with core permeability results. Effective porosity estimated from petrophysics was modelled using a shale volume approach.
Core data (336 wells)	Sufficient depth Sufficient recovery to visibly interpret core Public core analysis	Facies characterization (porosity [total]; permeability [vertical & horizontal]) Net to gross ratio Guide log interpretation in areas without core	Core was described and analyzed by E3 (41 cores). Publicly available core analysis was leveraged for effective porosity, which was measured using helium injection and Boyle's Law (Boyles Law, n.d.) and permeability, and core was calibrated to petrophysical log data.
Drill stem tests	Sufficient depth Copies of original drill stem tests available Liquid fluid inflow Minor amounts to no gas production Multiple build-ups (2nd Horner Extrapolation to cross-check validity)	Reservoir pressure Formation permeability [horizontal]	Data collected during drill stem tests are compiled by the Government of Alberta and were accessed through third party software. Drill stem test data was reviewed to determine representative Leduc reservoir pressure and permeability in the resource areas, following a quality assurance (QA) program that eliminated suspect or erroneous data. After completing the QA program, a pressure data set of 33 drill stem tests within the Bashaw District with pressure measurements considered representative of the Leduc reservoir pressure. The resulting data set consisted of 30 pressure measurements in the Leduc Formation and 3 pressure measurements in the Cooking Lake Formation. These measurements were distributed throughout the resource area and were measured between 1957 and 1980. These pressure measurements were used to estimate the current day reservoir pressure and to contribute to the characterization of the hydraulic continuity of the resource brine.

Data Type	QA/QC Criteria	Data Useage	Note
Seismic (6 regional lines)	Data was of reasonable vintage to be useful for interpretation Data was high enough quality/resolution	Qualitative porosity indicator Validates reservoir thickness over areas that have no wireline logs or other geological data	Seismic data is data collected by measuring rock properties using physics principles. It is based on the theory of elasticity and tries to deduce elastic properties of materials by measuring their response to seismic waves. Use of seismic can help to measure rock properties (such as the thickness of the reservoir and the structure of the reservoir, and porosity). It is useful as the seismic lines are continuous over areas where there is no well data and can be used to interpret areas where the wireline and drilling data are sparse/not present.

Figure 7-1: Area Map of Bashaw District



Note: Figure prepared by E3, 2024. Cross section reference lines A-A' (Figure 7-3), B-B' (Figure 7-4), and C-C' (Figure 7-5).

In the absence of well data, existing industry-standard Leduc edge interpretations were consulted (Switzer et al., 1994; Potma et al., 2001; S&P Global Accumap, 2024). The local and regional geological context was also taken into consideration when making interpretations.

The Leduc Formation sits atop the limestones and dolomites of the regionally extensive Cooking Lake Formation, which is differentiated from the Leduc Formation by the presence of a regional argillaceous (shale) zone (Figure 7-2).

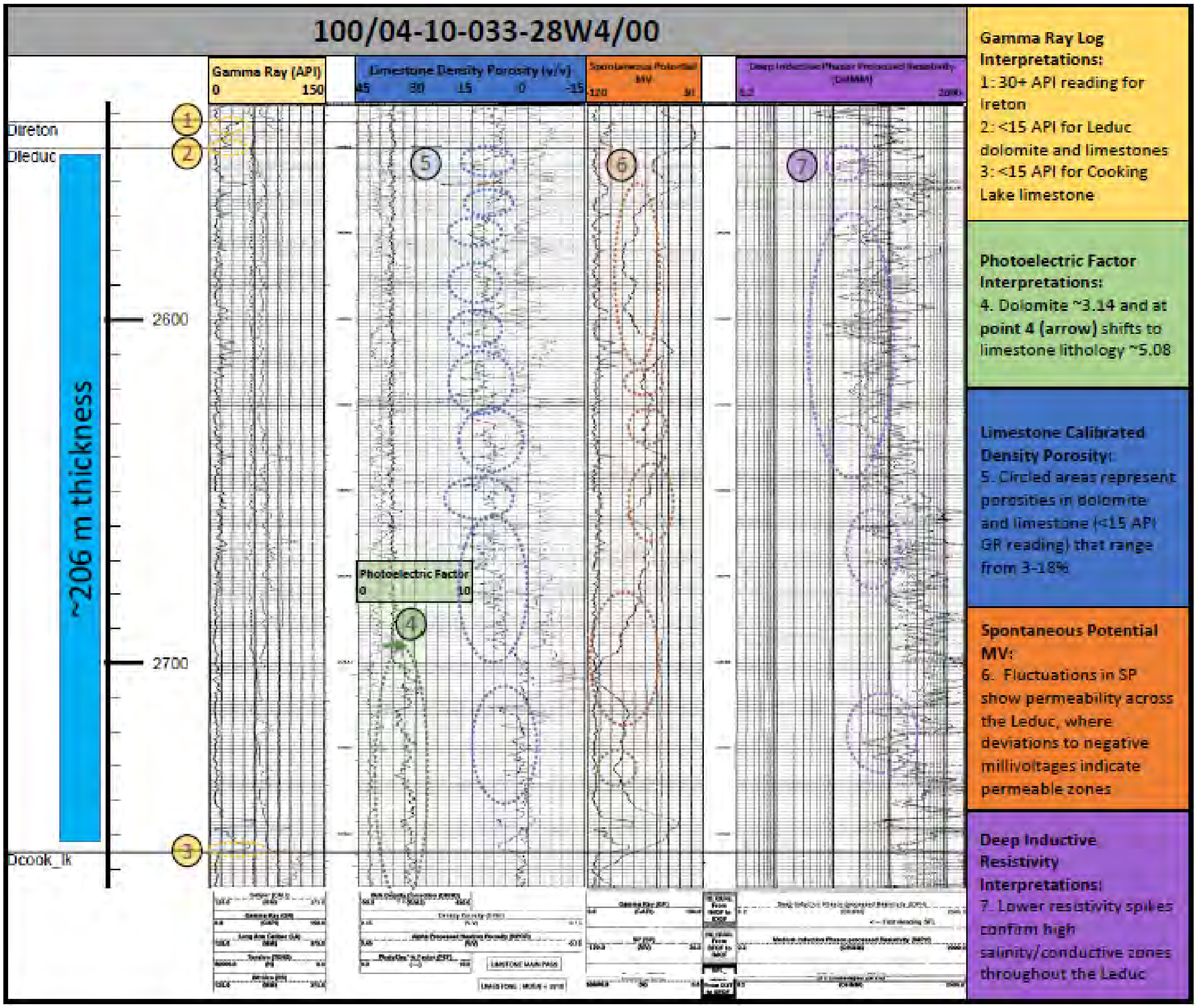
This argillaceous zone is not present in all wells, and in those cases the top of the Cooking Lake Formation was defined based on offsetting wells using relative thicknesses and geological context. Generally, the Cooking Lake Formation has a slightly higher gamma ray response than the Leduc Formation. The base of the Cooking Lake was selected where the more argillaceous Beaverhill Lake Group rocks became evident.

The Leduc reef built upwards from the Cooking Lake platform and occurs today as a prominent feature in the stratigraphic column. There are numerous Devonian reef complexes across the Western Canadian Sedimentary Basin. These reef complexes promoted growth over long periods of time and, in the permit areas reach thicknesses of close to 300 m in places. In the Bashaw District, the most prominent reef complex is the Bashaw Reef Trend (Schlager, 1989). These reefs are overlain and encased laterally by the shales of the Ireton and Duvernay Formations.

The permeability of the Cooking Lake Formation was measured in core from two wells. Based on the core plug permeabilities the permeability of the Cooking Lake Formation is in the range of 3 mD (Table 7-2). Table 7-2 also presents this permeability value as a hydraulic conductivity value assuming water properties of 1,150 kg/m^3 density and a dynamic viscosity of 4×10^{-4} Pa.S.

Well 100/04-10-033-28W4/00 (starred location on Figure 7-1), presents a type log suite of the interior lagoonal facies of the Leduc reef (Figure 7-2). The top and base of the Leduc Formation are picked from wireline log suites across the Bashaw District. The Ireton Formation overlies the Leduc Formation and can consist of mudstone to argillaceous dolostone, which are characterized by a much higher radioactivity than the Leduc Formation lithologies. This type of Ireton lithology is associated with a higher response in the gamma ray log (+30 API), compared to the carbonate rich Leduc and Cooking Lake Platform rocks with very low radioactivity, and have APIs of <15. In some locations, the Ireton Formation is comprised of calcareous shale, and the contrast in gamma ray response between the Ireton and underlying Leduc Formation can be more challenging to define on logs. Core to log calibrations have assisted in correctly picking the base Ireton Formation when its lithology is more calcareous.

Figure 7-2: Interior Lagoonal Facies Type Well (100/04-10-033-28W4/00



Note: Figure prepared by E3, 2022. The type well shows a log suite representative of criteria and rock properties interpreted from the logs that are used for picking the top and base of the Leduc reservoir.

Table 7-2: Cooking Lake Permeability and Hydraulic Conductivity

Count of Cooking Lake Wells with Core Plugs	Count of Core Plugs with Permeabilities	Geometric Mean of Average Kmax in Each Well (mD)	Average of Harmonic Mean of Kmax in Each Well (mD)	Representative Permeability (mD)	Representative Hydraulic Conductivity (m/s)
2	46	3	0.13	3	9E-08

Note: Kmax = maximum permeability

Other logs presented in Figure 7-2, showcase interpretations of rock properties, specific to the Leduc reservoir. The photoelectric factor log shows the shift close to the base of the Leduc, where limestone, which has a reading of about five barns/electron (Schlumberger Educational Services, 1989), is the more dominant lithology. The neutron density, spontaneous potential and resistivity logs, all show fluctuations that are indicative of the porosity and permeabilities across the reservoir, and as well the high saline conductive brine that occupies the pore space.

Cross-section A-A' (Figure 7-3) in the Exshaw sub-project area demonstrates the reservoir continuity across the north Bashaw District area Leduc platform. It highlights the relative thickness of the interior lagoonal facies of the Leduc reef complex as well as the corresponding hydrocarbon pools.

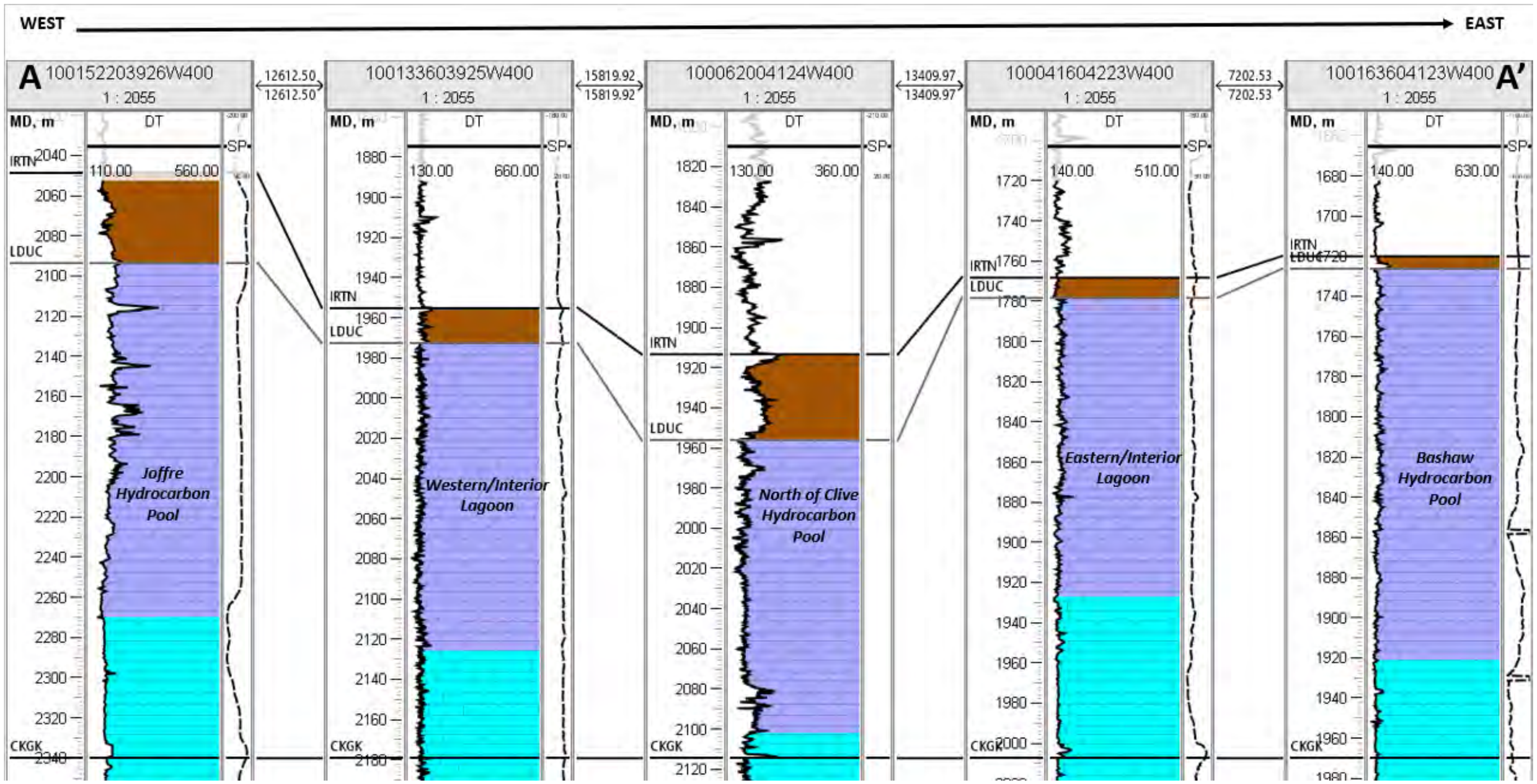
Cross section B-B' (Figure 7-4) in the Clearwater Project area demonstrates the continuity of the reservoir hosting the brine resource across the south Bashaw District Leduc platform and the Clearwater Project area. It highlights the relative thickness of the Leduc hydrocarbon pools at Innisfail and Wimborne to the interior lagoon and the basinal Duvernay mudstones and finer-grained carbonates along on the east side.

Cross section C-C' (Figure 7-5) highlights the brine reservoir continuity across a northeast to southwest trend of the Bashaw district Leduc reef. It showcases a thicker Leduc reef complex at the northeastern tip (Duhamel hydrocarbon pool), similar thicknesses of 200^{+} m in both reef interior wells (100/13-36-039-25W4/00 and 100/04-10-033-28W4/00), and a thickening of the reservoir in the southwest portion of the Bashaw District.

The low permeability basinal shales and carbonate muds of the Duvernay and Ireton Formation conformably encase and overlay the Leduc buildups, creating traps and seals for hydrocarbon pools and lithium resource brine.

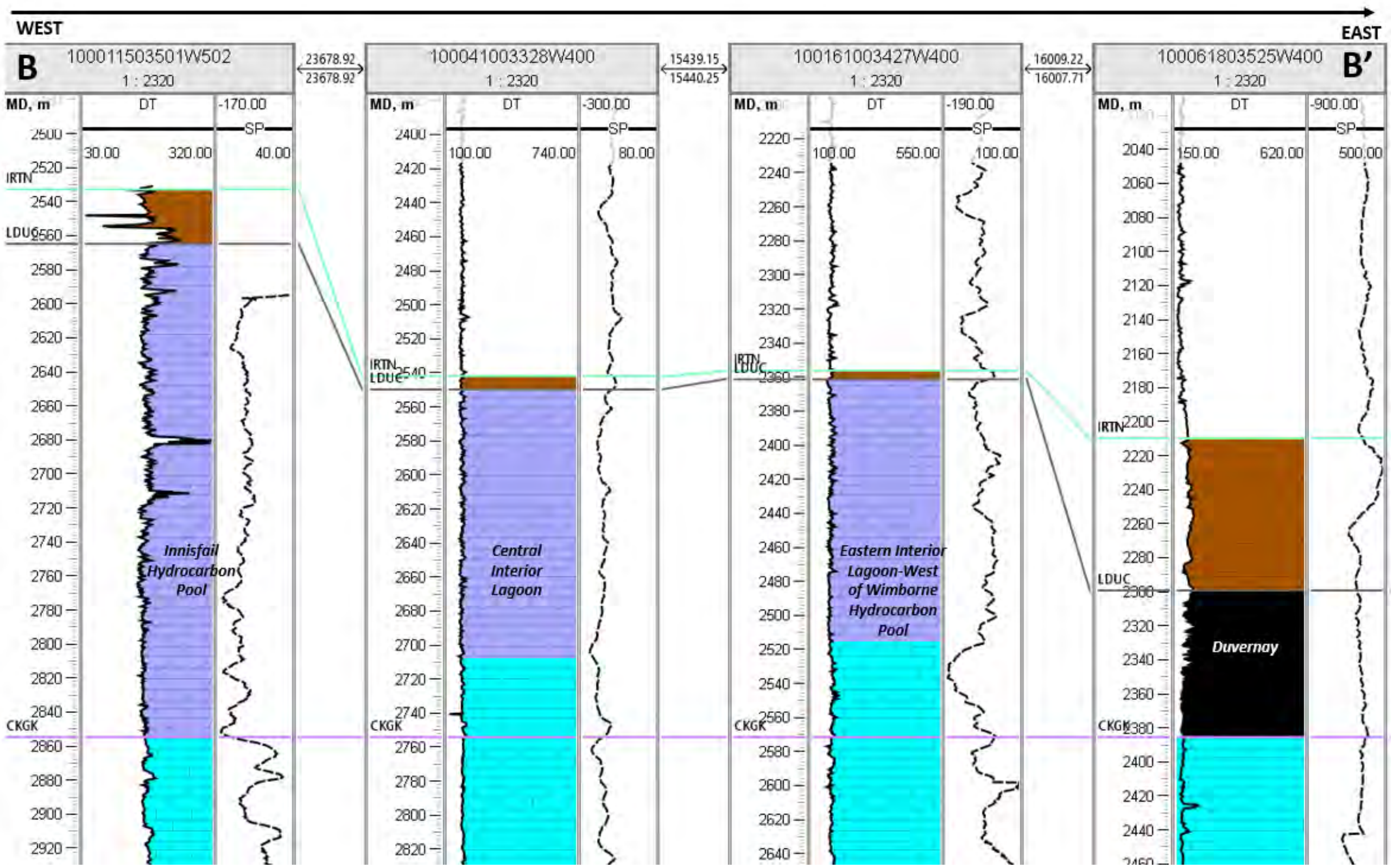
Schematic representations of current relationship of the geology, structure and hydrocarbon pools in the Bashaw District can be seen in Figure 7-6 (to scale with vertical exaggeration).

Figure 7-3: Stratigraphic Cross Section A-A', North Bashaw District, Cooking Lake Datum



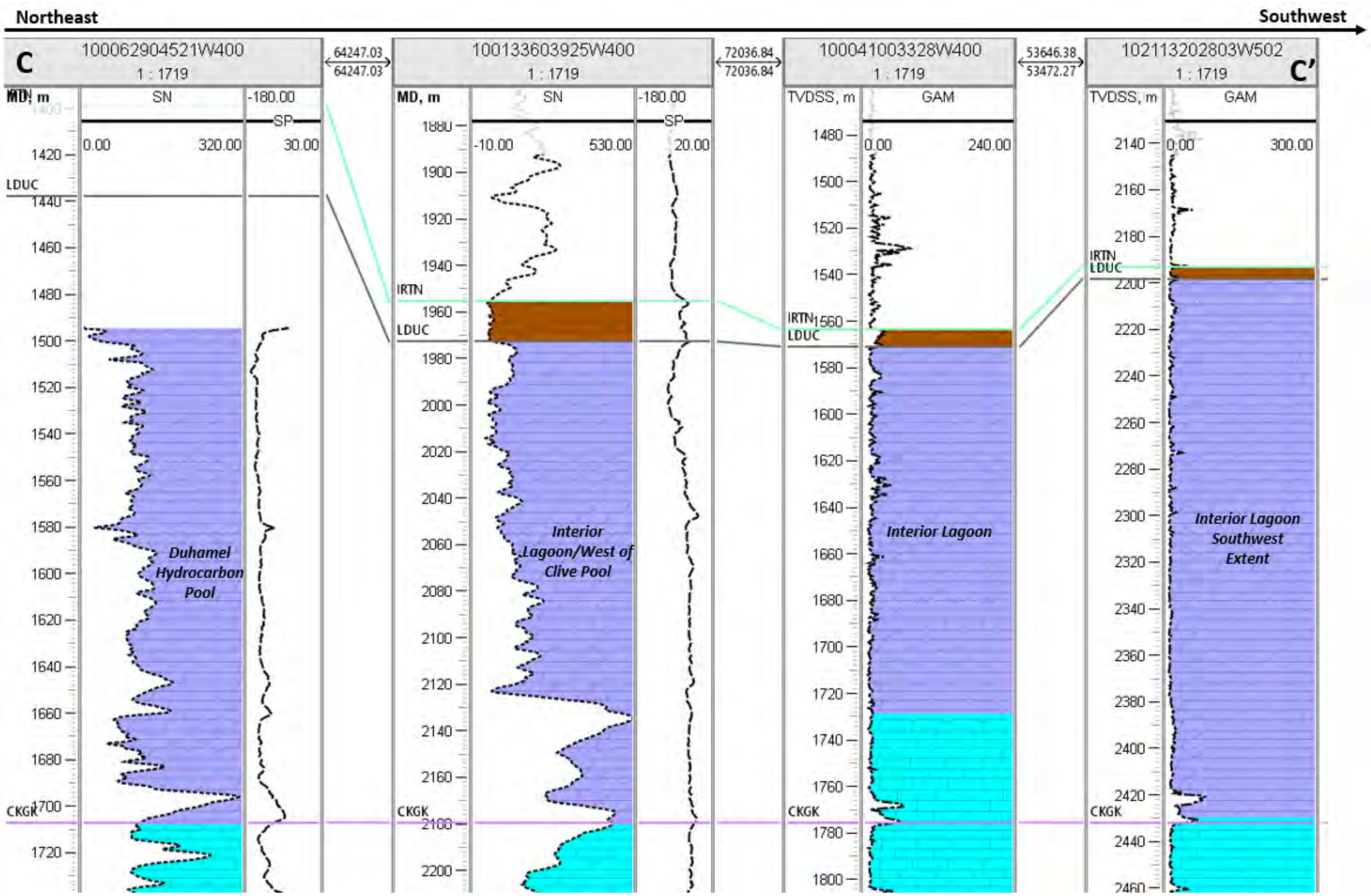
Note: Figure prepared by E3, 2022.

Figure 7-4: Stratigraphic Cross Section B-B', South Bashaw District, Cooking Lake Datum



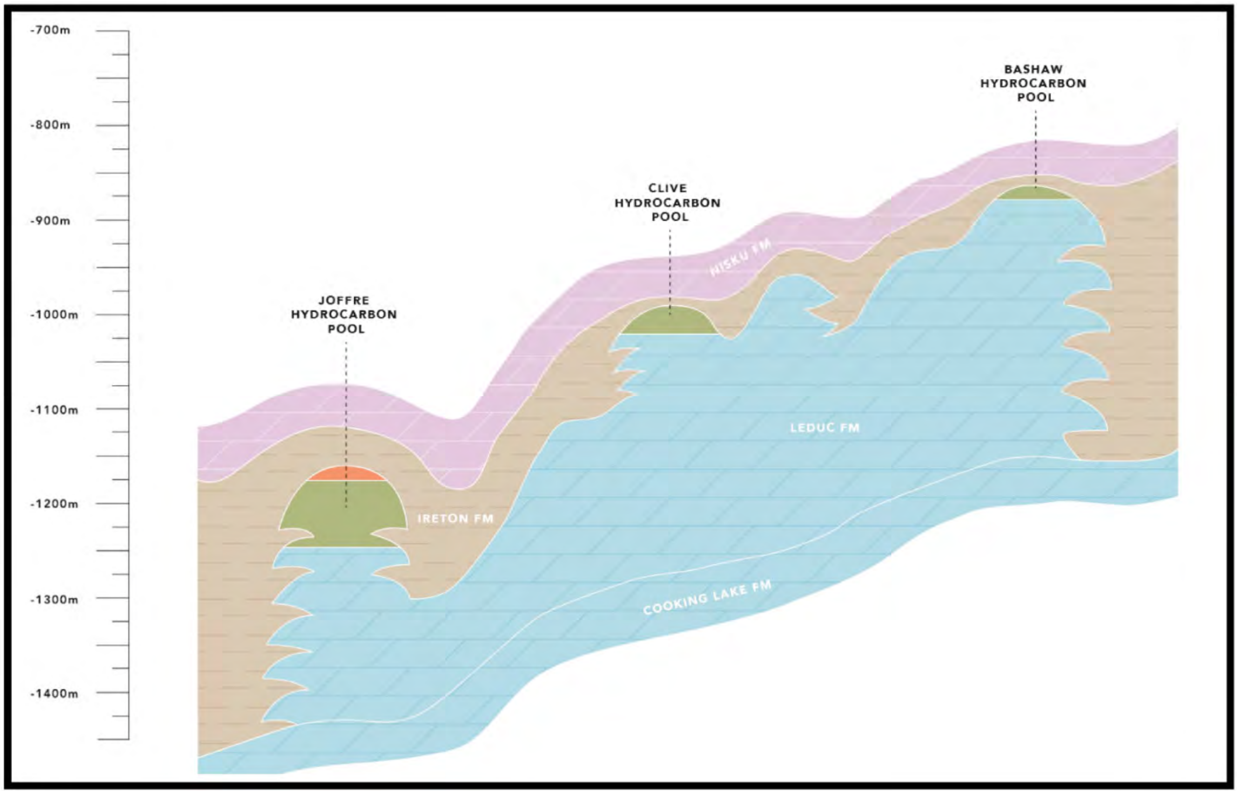
Note: Figure prepared by E3, 2022.

Figure 7-5: Stratigraphic Cross Section C-C', Northeast to Southwest Trend Across the Bashaw District, Cooking Lake Datum



Note: Figure prepared by E3, 2022.

Figure 7-6: Schematic Representation of the Bashaw District



Note: Figure prepared by E3, 2018.

The Leduc and Cooking Lake Formations were partially to completely replaced by dolomite (Drivet and Mountjoy, 1997; Mountjoy, et al., 1997; Mountjoy et al., 1996; Mountjoy et al., 1995; Mountjoy et al. 1995). Dolomitization is the chemical process by which limestone ($CaCO_3$) is converted to dolostone ($CaMg(CO_3)_2$) through the dissolution of calcium carbonate and the precipitation of dolomite (James and Jones, 2015). The smaller ionic radius of magnesium, compared to calcium, creates a volume reduction when magnesium replaces a calcium to form dolomite. This volume reduction can create enhanced porosity and permeability in a reservoir (James and Jones, 2015; Reeder, 1983).

There are many possible mechanisms theorized as to the source of dolomitizing magnesium-rich fluids and the method for their transport into the Leduc reefs in the southern Alberta basin, but few published studies specifically for the Bashaw District area (Atchely et al., 2006; Amthor et al., 1994; Machel,et al., 2002). Across the Bashaw District, dolomitization of the Leduc Formation generally enhances the porosity and permeability of the reservoir.

Speculation exists as to the source of the lithium for the lithium-enriched brines of the Woodbend and Winterburn groups in the Western Canada Sedimentary Basin, but the source is ultimately unknown (Eccleset al., 2012). For the Leduc and Nisku system in southern Alberta, Huff (2016) proposed a source involving lithium concentrated Devonian evaporites to the west and upward movement of lithium-enriched brine into the Leduc and Nisku Formation carbonates during later mountain building.

Regardless of the source of the lithium, the theories suggest that the lithium enrichment into the brine occurred prior to the brine migration into the Woodbend Group, which supports the observed data of low variability in lithium concentrations across the Bashaw District.

7.3.4 Leduc Lithostratigraphic Facies

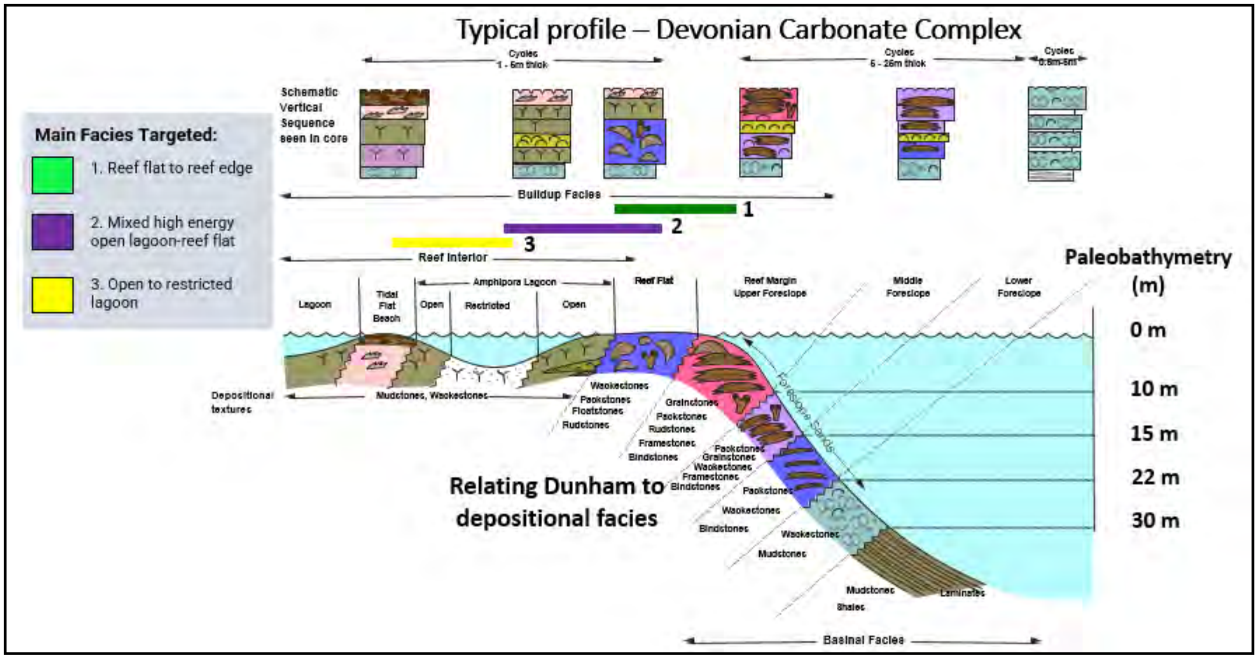
The Leduc reef complex lithology across the Bashaw District (Figure 7-7), data for which are biased to the upper section (where most of the cores intersect), showcase fully dolomitized lithologies, therefore original fabric and skeletal, and or non-skeletal grain makeup can be indistinguishable at best. Photoelectric factor well logs that intersect the entirety of the Leduc Formation, indicate limestone shifts (refer to Figure 7-2) a change from dolomite at approximately three to limestone at approximately five barns/electron in either the Leduc Formation or underlying Cooking Lake Formation and were used to validate neutron-density lithology interpretations. Based on these well logs, it is evident there are vertical and lateral variations in the dolomitization trends across the complex.

Lithofacies were identified, interpreted, and delineated based on sedimentary structures and textures observed in core, and can be related to trends of porosity and permeability. Trends of porosity and permeability occur spatially and relate to depositional environments and diagenesis of the rock (McNamara and Wardlaw, 1991; Amthor et al., 1994; Mountjoyet al., 2001; Atchelyet al., 2006), and these trends formed the basis for stratigraphic definitions and facies coding used in this Report. The depositional model (Figure 7-8) showcases the three main facies identified and differentiated across the Bashaw District. Except for core 102/01-16-033-27W4, all cores examined by E3 were in the upper portion of the Leduc reef. Therefore, these facies interpretations are representative of the upper third of the Leduc Formation.

These lithofacies were interpreted mainly by core descriptions across the Bashaw District (Figure 7-8). They are subdivided as follows:

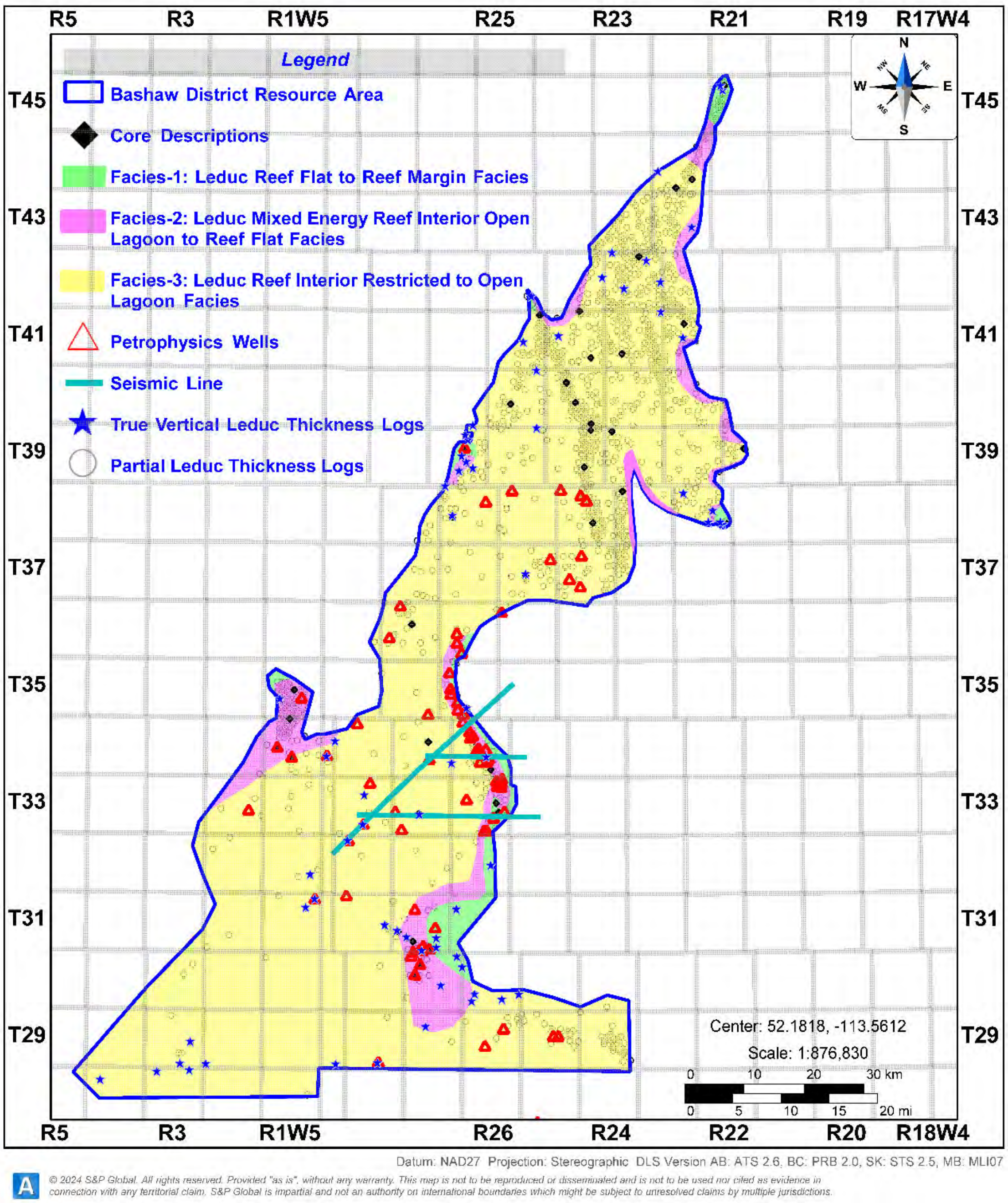
- Facies-1: Leduc reef flat to reef margin facies;
- Facies-2: Leduc Mixed reef interior open lagoon to reef flat facies;
- Facies-3: Leduc reef interior restricted to open lagoon facies.

Figure 7-7: Depositional Model For Typical Devonian Carbonate Complex, With The Three Facies Interpreted In The Upper Leduc Core In The Bashaw District



Note: Figure prepared by E3. Credit: with permission from Drivet Geological Consulting, and modified from Wendt et al. (1982); and Wendt (1992).

Figure 7-8: Upper Leduc Facies Distribution In The Bashaw District Based On Core Descriptions



Note: Figure prepared by E3, 2022.

Facies-1 and Facies-2 indicate depositional environments closer to the zero edge of the reef complex. Textures in the core of the Facies-1 and -2 lithofacies suggest reworking of sediments (coated grains and reefal debris) along with in-situ reef growth with submarine cements including rudstone to framestone (Embry and Klovan, 1971), combined along with grain-supported rock types including grainstones and packstones (Dunham, 1962) (Figure 7-9).

Facies-2 reef flat to reef interior open lagoon, is also characterized by grain supported rock types. By these criteria, it is interpreted both of these facies represent parts proximal to the reef margin where most of the aggradation and reef growth occurred (Figure 7-10). In addition, both Facies-1 and Facies-2 typically have highest porosity and permeabilities; this could be a result of proximity to the zero edge of the preserved reef, where higher degrees of filtering of finer grained material that would largely comprise the bulk of the matrix makeup of these facies, is occurring.

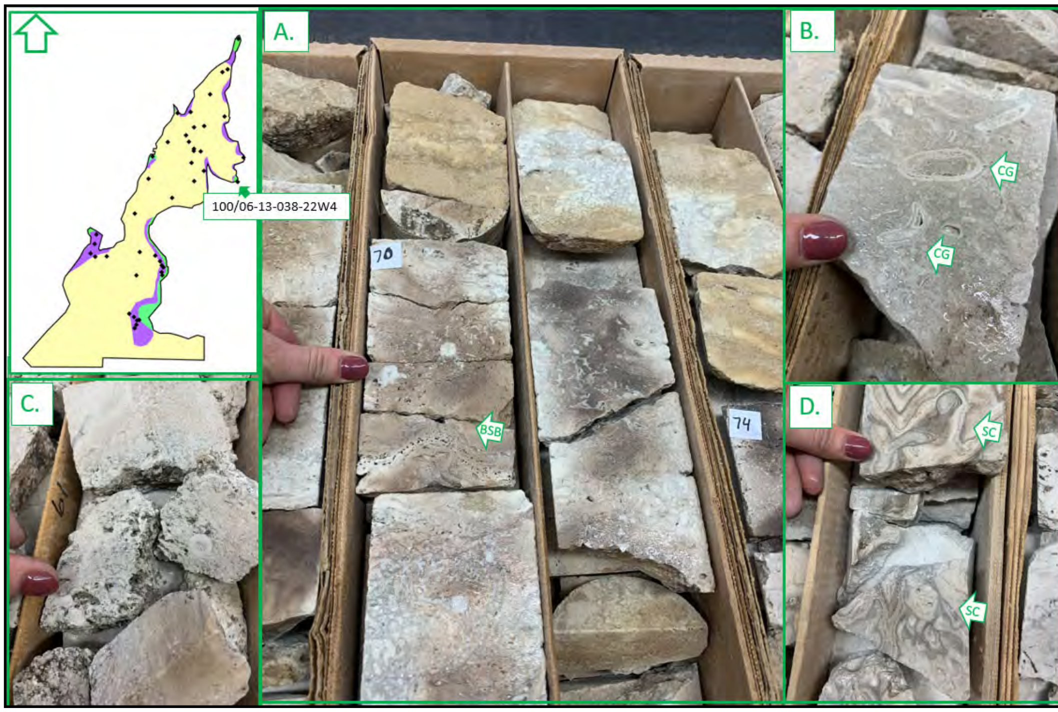
Facies-3 is the dominant facies occurring in much of the interior of the Bashaw reef complex, on the back side of the reef flat. The reef interior is dominated by lagoons (Figure 7-11). These depositional environments are vertically more heterogeneous and consist of carbonate muds, storm wash-over debris, shoal reef material, and occasional patch reefs. Cores in the lagoon showed evidence for bioturbation, where a churned-reworked texture fabric was noted and was interpreted as being a primary depositional texture.

Rock types representative of this facies in the core are dominantly matrix supported including floatstone with wackestone and mudstone matrix. Overall, the dominant skeletal reef builder in the Leduc complex across the Bashaw District and across each all three of the lithofacies are stromatoporoids.

Characterizing cycle geometry for the Leduc in the study area is challenging because of the sparse well, core, and seismic data control in the Middle and Lower Leduc cycles. Based on the available data, the facies were assumed to be vertically continuous throughout the reef thickness. Drilling new wells through the full Leduc thickness away from existing Leduc data helped to interpret the geometry of the lagoon in the middle portion of the reef complex where there was previously sparse data, and clarified some of the previous assumptions about porosity, permeability, and cyclicity within the lagoon facies within the Bashaw District, which allowed for greater confidence when building the geological model.

Although three lithofacies were identified and have been mapped by E3, the resource volumes were determined using reservoir properties modelled for the combined Leduc reef complex volume within the Bashaw District. This is considered to be a reasonable representation of the reservoir, as the important influence of facies distribution on the resource estimate is the facies controls on porosity and permeability.

Figure 7-9: Reef Flat to Reef Margin Facies



A. Bulbous stromatoporoid bindstone (BSB) with vuggy porosity and oil staining; core plug at 70 has a k90 permeability of 17.94 mD and porosity measurement of 8.9%

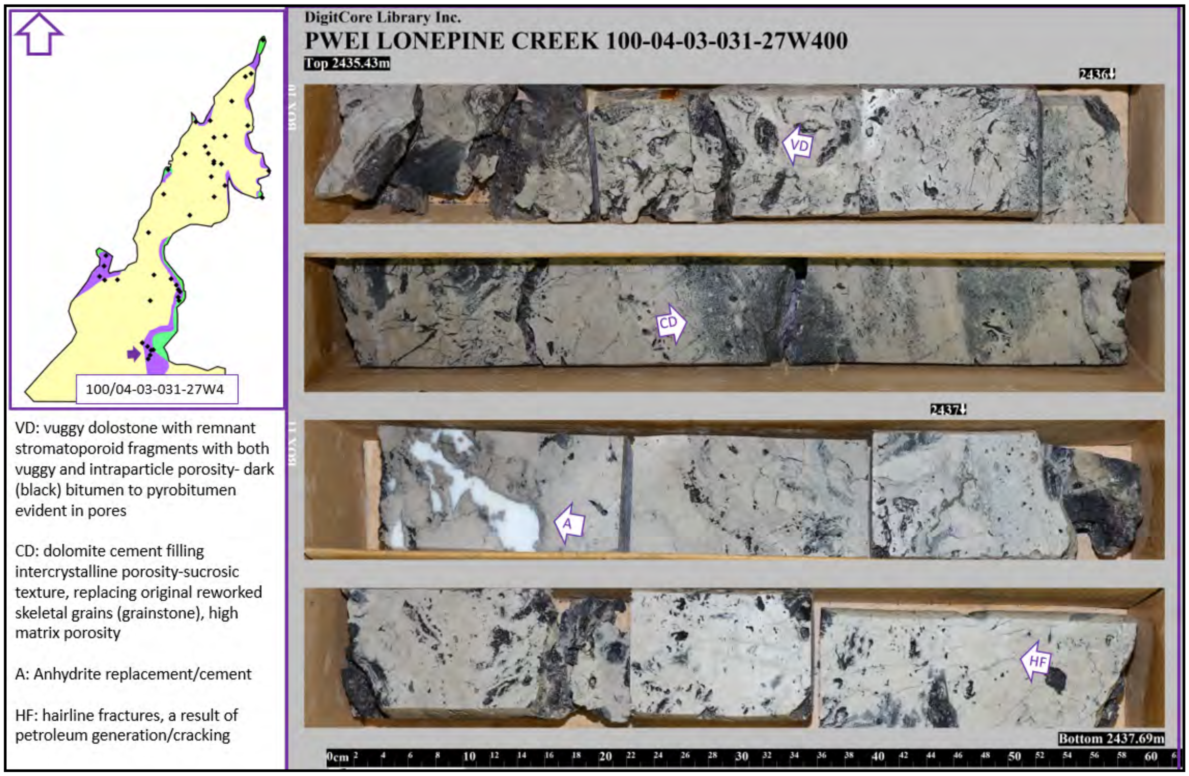
B. Rudstone with coated grain clasts (oncoliths), vuggy and intraparticle porosities targeting nuclei

C. Stromatoporoid (dendroid, laminar and bulbous), coral, echinoderm, bivalve and brachiopod grainstone with intraparticle porosity to vuggy porosity selective to laminar stromatoporoids and interparticle porosity between skeletal grains

D. Submarine cement (SC) between and fully replacing dendroid and laminar stromatoporoids

Note: Photography by Eva Drivet/Doug Hayden, 2022. 100/06-13-038-22W4 core photos; this core is primarily limestone (localized to this area) and intersects the Upper Leduc Formation.

Figure 7-10: Open Lagoon to Reef Flat Facies



Note: Photography by Eva Drivet/Doug Hayden, 2022. 100/04-03-031-27W4 core photos; this core is proximal to the Lone Pine hydrocarbon pool and is a vuggy dolostone.

Figure 7-11: Restricted to Open Lagoon Facies

Note: Photography by Eva Drivet/Doug Hayden,2022. 100/03-13-034-29W4 core photos; core is interpreted as restricted lagoon facies.

Because porosity data measured directly from the facies were used to populate the 3D porosity distribution, this is considered to be an adequate representation of these large-scale facies trends for the purpose of the resource estimate. Further discussion is provided in Section 14.

Petroleum well data were used to define the shape and extent of the Leduc reservoir. Defining the geometry of the Leduc reservoir was an iterative process which involved analysis of existing wells drilled for the exploration and production of hydrocarbons in the Brine Resource area. This geological mapping process using well data has been in practice in Alberta’s petroleum industry for over 70 years to define geological formations. The Leduc base and top were determined from well logs and seismic interpretation.

7.3.5 Reservoir Dynamics

E3 conducted a flow test program on its 1-16-033-47W4 location to directly measure reservoir pressure and pressure response from production and injection into the reservoir. The flow test comprised

- A production test flowed 400 m^3/d of brine to surface for five days;
- A pressure build-up for seven days;

- An injection test of 1,200 m^3/d for two days;
- A pressure fall-off for two days.

The pressure response was interpreted by an independent third-party subject matter expert from IHS Markit, a division of S&P Global. The interpretation relates the pressure response recorded to reservoir permeability of 20mD-100mD, and a minimum area of investigation of 3.1 sections (3.2 km). Because the test was a single well test, total system compressibility could not be reliably estimated from the test and was assumed as a constant (for a single-phase system) for the purposes of the analysis. The analysis was independently validated by the QPs who also analyzed the test results using different software and obtained comparable permeability estimates.

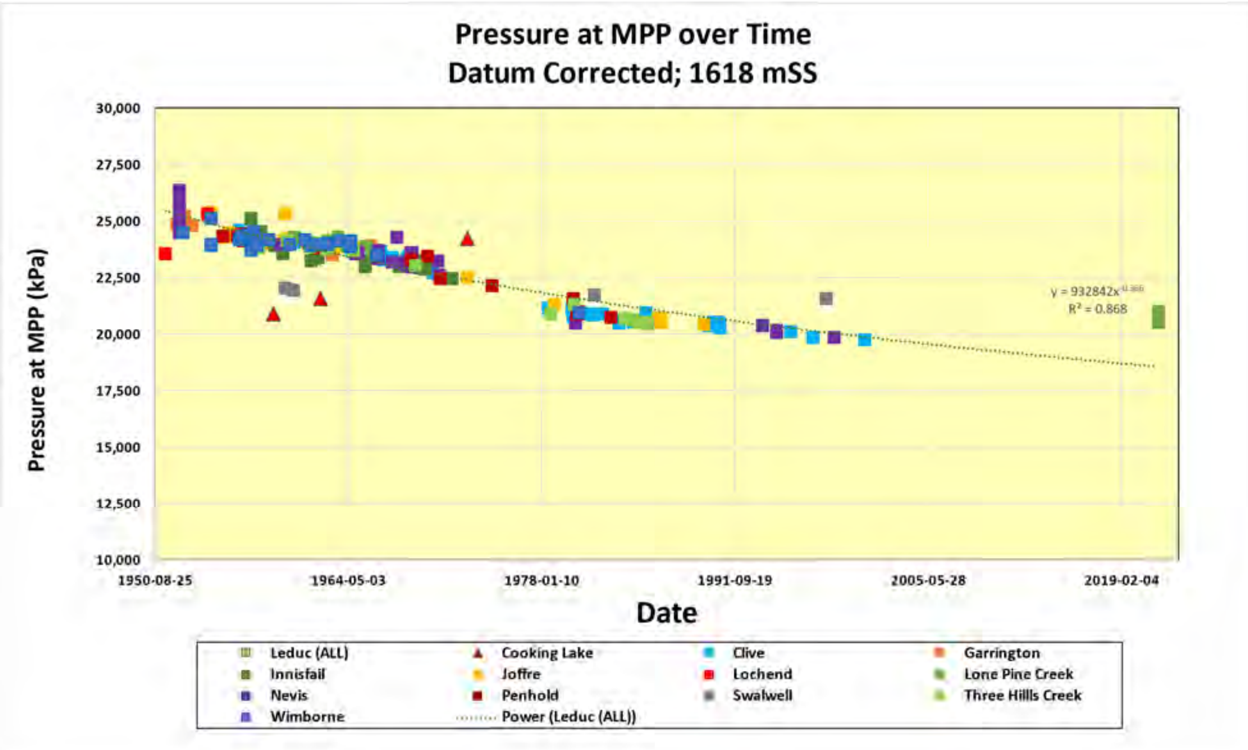
The data acquired from flow test complements the previous analysis of drill stem test data from 327 wells with Leduc or Cooking Lake Formation extrapolated pressures that passed quality control and were used in an area surrounding and including the resource area. Drill stem test are downhole tests that can yield pressure and permeability (flow capability) measurements from a specific depth interval.

Leveraging this publicly-available pressure data, E3 graphed the data from the Bashaw Trend and the underlying Cooking Lake Platform. The pressure data were measured in wells distributed throughout the Brine Resource area. The data were graphed both as pressure vs. time and pressure vs. depth as both of these plots can be used to infer pressure continuity in the reservoir (Figure 7-12, Figure 7-13).

The pressure vs. time is interpreted to show reservoir continuity if pressure decline in the reservoir during production follows a singular regional trend. The pressure vs. depth data can also be interpreted to support pressure continuity if the data follow a singular hydrostatic gradient (approximately 10 kPa/m), assuming static (i.e., non pumping) conditions. The pressure vs. time data shows that within the Bashaw trend, the Leduc is hydraulically connected across the reef to the lagoon portions of the reef complex (Figure 7-13). The underlying Cooking Lake Platform has lower permeability and porosity than much of the Leduc Formation. Limited pressure data indicated that the pressure is different than the regional Leduc pressure (Figure 7-13), but it may be in communication with the Leduc Formation due to the fact that there are limited data showing porosity and permeability (refer to Table 7-2).

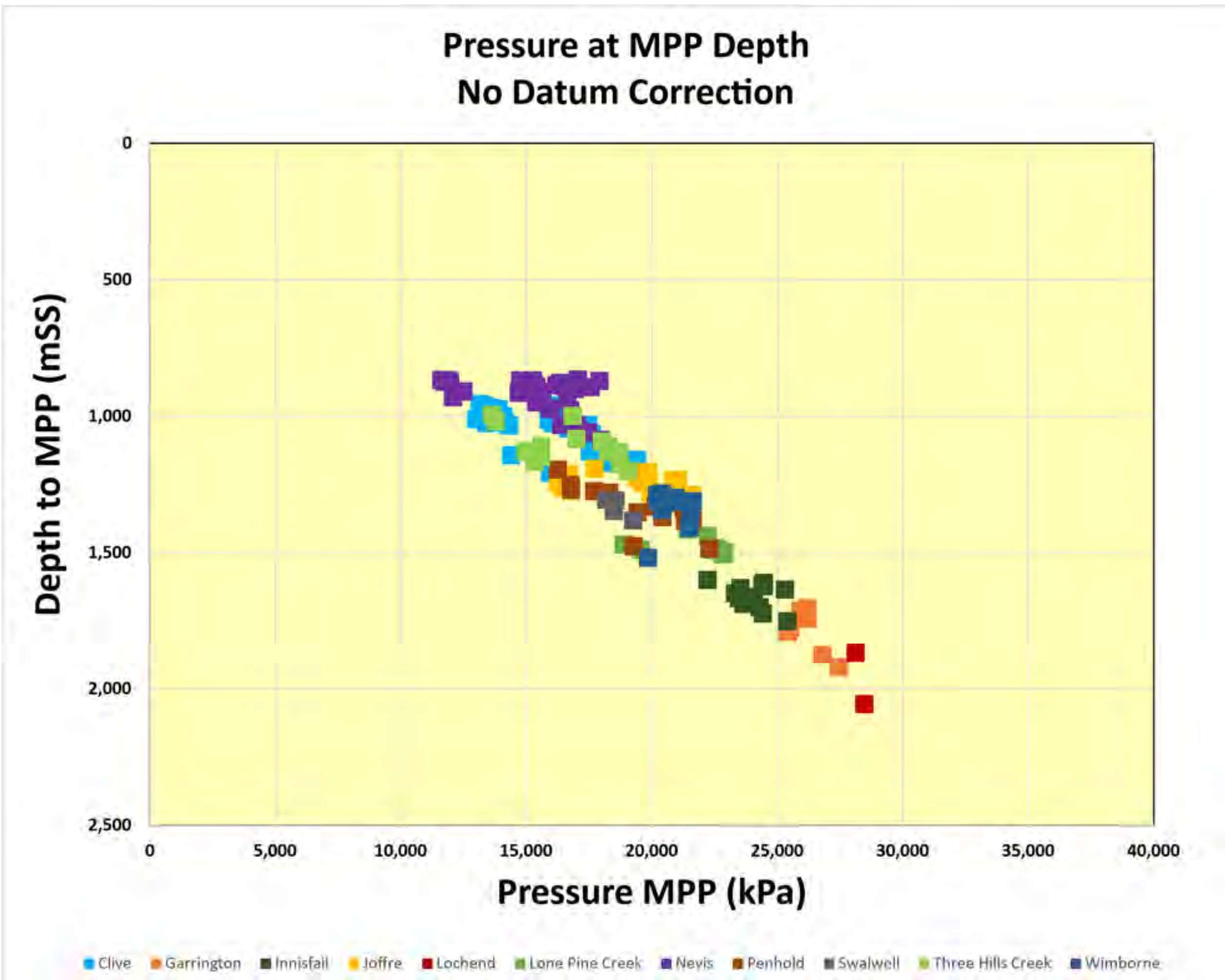
If the Cooking Lake Formation has some areas or facies with higher porosity and permeability this could allow some pressure and fluid communication through the Cooking Lake Formation over time.

Figure 7-12: Leduc Regional Pressure vs. Time Data



Note: Figure prepared by E3, 2024.

Figure 7-13: Leduc Regional Pressure vs. Depth Data



Note: Figure prepared by E3, 2024.

The pressure vs. depth data indicate that generally the Leduc reservoir pressures follow a single hydrostatic pressure gradient over the Bashaw District area (Figure 7-13), despite the fact that this data was collected during non-static, time transient conditions across a significant areal extent. The data were grouped by hydrocarbon field, which are geographically distributed throughout the Bashaw District, encompassing all three facies types identified. This supports that the Leduc reservoir is hydraulically connected across the high energy reef flat to flat open lagoon to low energy/more restricted lagoon portions of the reef.

Based on the production and injection volumes, E3 calculated the overall void replacement ratio for the Bashaw District (Figure 7-14). The void replacement ratio is an oil and gas term describing the ratio of volumes of injected fluid to produced fluid at reservoir conditions, and a VRR of 1 is required to maintain reservoir pressure. The Bashaw District void replacement ratio is 0.39, which correlates with the decrease in reservoir pressure since the 1960s.

While the overall Bashaw District voidage replacement ratio is significantly under 1 at 0.39, injection of both water and gas does occur in some pools. The orange circles in Figure 7-14, found in the northern portion of the Bashaw District, show areas where the void replacement ratio was > 1, meaning that cumulative injection volumes are greater than cumulative produced volumes. While injection does also occur in the southern portion of the Bashaw District, the void replacement ratio is < 1, meaning that cumulative injection volumes are less than the cumulative produced volumes. These conditions will influence the modern-day pressure distribution in the reservoir relative to its original static conditions.

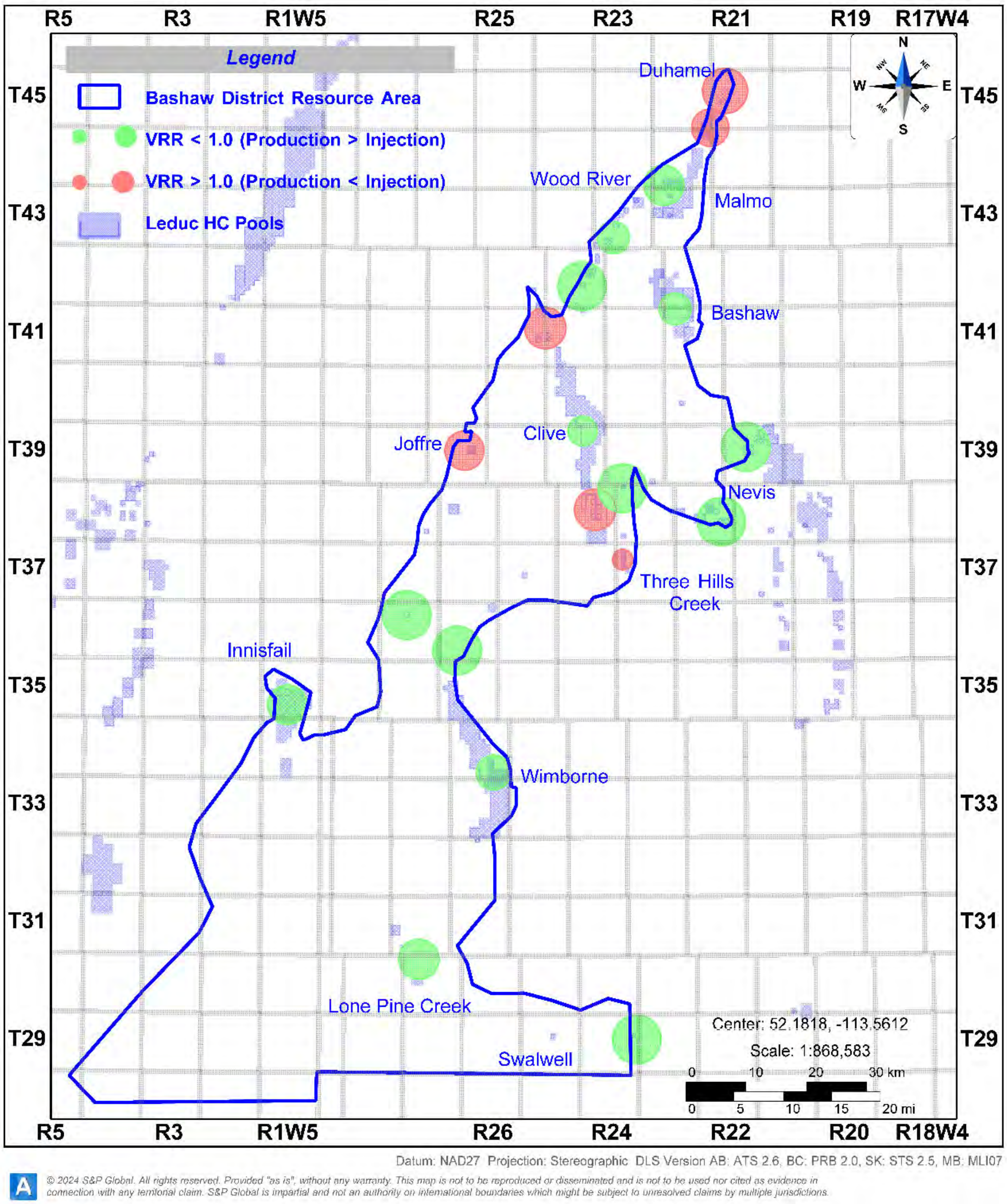
7.3.6 Mineralization

Most saline reservoirs in Western Canada have little to no lithium entrained within the brines. For the purposes of this Report, “enriched” would refer to any brine reservoir that has more that 30 mg/L of lithium. The potential for lithium-enriched brine in the Devonian petroleum system of Alberta was initially identified by Hitchon et al. (1995). Potential reservoirs were located in reef complexes of the Woodbend and Winterburn Groups. Subsequent work by Eccles and Jean (2010), Huff et al. (2011; 2012) and Huff (2016) measured the presence of elevated lithium (e.g., >75 mg/L Li) in reservoirs associated with the Devonian reef complexes.

The main lithium accumulations in E3’s properties occur within brines contained within dolomitized reefs complexes of Devonian-aged Leduc Formation, with a secondary accumulation occurring at a higher elevation in the biostromal development in the Nisku Formation of the Devonian Winterburn Group. Consequently, lithium-brine mineralization in the Project area consists of lithium-enriched brines that are hosted in porous and permeable reservoirs associated with the Devonian carbonate reef complexes.

The specific emplacement method for the lithium in these reservoirs is currently unknown, and is an active area of research. For the Leduc and Nisku system in southern Alberta, Huff proposed a source involving lithium concentrated Devonian evaporates to the west and upward movement of lithium-enriched brine into the Leduc and Nisku carbonates during later mountain building (Huff, 2016). E3’s current conceptualization of the Brine Resource is that the lithium grade is relatively homogeneously distributed within the connected reservoir of the Bashaw District due to the relatively high permeability and connected nature of the reservoir.

Figure 7-14: Voidage Replacement Ratio from Hydrocarbon Pools Across the Bashaw District



Note: Figure prepared by E3, 2024.

Data collected during E3's 2022 evaluation well program supports this theory, as all samples collected have a very narrow range of P10–P90 concentrations. The lithium data were collected across the 65+ townships of the Bashaw District, and E3's evaluation well program acquired lithium concentrations across the vertical extent of the Leduc Formation.

Additionally, major cation and anion geochemistry concentrations do not vary significantly across the Bashaw District, which further supports the interpretation that the brine is continuous. A summary of this information is presented in Table 7-3.

7.4 QP Comments on Section 7

The QP notes:

- The majority of data used for geological characterization comes from historical, publicly-available oil and gas data collected by others but the raw data were available and used for during Brine Resource evaluation;
- Historical, publicly-available lithium grade data were validated to the extent possible and were consistent with data collected by E3, but were not used in the grade estimate.

Table 7-3: Major Ion Distribution Across the Bashaw District

	Bicarbonate (mg/L)	Dissolved Chloride (mg/L)	Dissolved Sulphate (mg/L)	Dissolved Calcium (mg/L)	Dissolved Magnesium (mg/L)	Dissolved Sodium (mg/L)	Dissolved Potassium (mg/L)
P90	310	127,280	186.7	19,120	2,562	44,060	5,782
P50	506	134,000	392.6	21,500	2,920	49,000	6,185
P10	772	162,000	515.8	24,900	3,434	53,440	6,669

8.0 DEPOSIT TYPES

The lithium brine in the Bashaw District is considered to be an example of a lithium-rich brine deposit.

8.1 Overview

Lithium deposits worldwide totalled ~80 Mt in 2020 (United States Geological Survey, 2020), and fall into two broad categories: hard rock (dominantly pegmatites) deposits; and lithium-rich brines.

Lithium clay or sedimentary deposits are an emerging resource, where lithium is found in clays in active salt lakes (highly evaporitic environments), in lacustrine evaporites, or from the weathering of volcanic rocks and their associated by-products. In addition, paleo-salar type deposits (buried salars) are another deposit type where highly concentrated lithium clays can exist (for example the Jadar deposit in Serbia). Hard rock deposits are commercially mined in Australia and China, with developments at various stages elsewhere across the globe.

Brine-hosted lithium deposits are accumulations of saline groundwater that are enriched in dissolved lithium and other elements that can occur at almost any depth between surface and the basement, and are commercially produced in Argentina, Chile, China, and the USA. Salars host lithium-rich brines that occur at or near surface and concentrate lithium (and other minerals) through solar evaporation.

Lithium brines associated with oil wells have been known for some time, but are typically lower in grade when compared to the major lithium deposits of the world such as the Salar de Atacama, Chile (site of production facilities of the two major producers Albemarle and SQM), Salar de Hombre Muerto in Argentina (home of the third major producer FMC) and Clayton Valley, USA (owned by Albemarle, and currently the only lithium production facility in North America). These existing sites use surface evaporation pools as part of the lithium concentration process. The recent advent of new dissolved metal recovery technologies and methods has made lower grade brines economically viable.

According to Eccles and Berhane (2011) *"The source of lithium in oil-field waters remains subject to debate. Most explanations generally conform with models proposed for Li-rich brine solutions that include recycling of earlier deposits/salars, mixing with pre-existing subsurface brines, weathering of volcanic and/or basement rocks, and mobilizing fluids associated with hydrothermal volcanic activity (e.g., (Garret, 2004)). However, none of these hypotheses has identified the ultimate source for the anomalous values of Li in oil-field waters".*

In a comprehensive investigation of lithium-isotope and elemental data from lithium-rich oil-field brines in Israel, Chan et al. (2002) suggested that these brines evolved from seawater through a process of mineral reactions, evaporation and dilution. In this case, brines that were isotopically lighter than seawater were associated with lithium mobilized from sediment. Huff (2016; 2019) suggests that lithium-brine in the Nisku and Leduc Formations is the result of *"preferential dissolution of Li-enriched late-stage evaporite minerals, likely from the middle Devonian Prairie Evaporite Formation, into evapo-concentrated late Devonian seawater"*, followed by downward brine migration into the Devonian Winnipegosis Formation and westward migration caused by Jurassic tilting. Finally, during the Laramide tectonics, the brine was diluted by meteoric water driven into the Devonian of the southwestern Alberta Basin by hydraulic gradients.

It has also been theorized that the source of lithium-enriched brines is associated with the magnesium-rich fluids responsible for pervasive dolomitization in the Leduc Formation. Stacey et al. (2020) proposes these deep basinal brines migrated from the Prairie Evaporite into regional reservoirs and were emplaced in part via large faults. Alternatively, the "reflux" dolomitization model proposed by Potma et. al. (2001), in which evapo-concentrated Nisku-aged fluids are responsible for wide-spread dolomitization across the Leduc in the Bashaw District, would suggest the lithium is potentially sourced from the later Devonian Nisku sea.

8.2 QP Comments on Section 8

The QPs acknowledge that while a specific emplacement model is uncertain, there are multiple potential emplacement models that are plausible to explain the occurrence of lithium-enriched brine in the Leduc Formation in the Project area.

The Leduc Formation represents a lithium-rich brine deposit hosted in a deep confined aquifer that is suitable for further exploration.

9.0 EXPLORATION

9.1 Introduction

Hydrocarbon production by oil and gas operators in E3's permit area is often associated with co-produced brine water from the formation. Significant volumes of hydrocarbons and brine have been produced from the Leduc reservoir since the 1960s, and this has resulted in a rich dataset. Over time, the relative amount of water produced from the Leduc Formation has increased in comparison to hydrocarbons. Water in some cases represents more than 98% of the total volume arriving at surface. Various oil and gas operators have allowed E3 access to oil and gas infrastructure for brine collection across the permit areas.

9.2 Grids and Surveys

Well locations were surveyed using NAD83.

9.3 Brine Sampling From Existing Wells

In addition to E3's 2022 evaluation well program (described in Section 10), exploration activities to date have included brine sampling from existing hydrocarbon wells. Samples were collected from existing Leduc Formation producing oil and gas wells by field technicians contracted by E3 from Bureau Veritas laboratory in Red Deer, Alberta (Bureau Veritas Red Deer).

All wells producing solely from the Leduc Formation, without any additional concurrent zone production (commingling from other formations), were identified for sampling, and were accessed based on availability. Oil and gas operators generally cycle wells, so several field programs were completed to collect samples. Samples were either collected directly at the wellhead, or at test separators, by Bureau Veritas employees wearing self-breathing apparatus due to the presence of hydrogen sulfide gas.

The following sampling procedure was followed such that samples were collected, sealed, and labeled to avoid contamination and tampering, and ensured proper chain of custody measures were in place.

9.4 Field Sampling – Existing Oil and Gas Infrastructure

Samples were either collected directly at the wellhead, or at test separators.

9.4.1 Wellhead Sampling

Where sampling was conducted at the wellhead, a 4 L jug was used to collect the production fluid at the pump jack. This fluid typically formed an emulsion of oil, water and gas, which readily separated out into phases in the bottle within seconds to minutes. Once the separation was complete, a small hole was created in the bottom of the bottle to allow only water to flow out of the 4 L bottle and into a 1 L opaque amber glass bottle (Figure 9-1).

9.4.2 Test Separator Sampling

Samples were also collected at test separators. Test separators are used in the oil and gas industry to measure the flow rates of various wells and collect water and hydrocarbon samples from one or more wells at a satellite location (Figure 9-2). Test separators for this resource sampling program were either 2-phase or 3-phase:

- 2-phase means that oil and water are separated from gas;
- 3-phase means that oil, water and gas are each separated.

For both 3-phase and 2-phase, there is a valve on the tank that can be opened to produce a fluid sample. In all cases, the hydrocarbon well operators ensured that the wells used went “into test” at least 24 hours prior to sample collection to flush the lines and minimize the risk of contamination from other wells.

On 2-phase separators, the valve was opened, and water was discharged into a test bottle to assess how much oil was in the separator before collecting directly into the opaque amber bottles. If there was a high volume of oil, sometimes the operator of the well was able to adjust on site to improve the amount of water flow. After adjustments were made, a mixture of oil and water was discharged into the 1 L opaque amber bottles.

On 3-phase separators, a bottle of water can be collected with very little gas or oil. In this case, the valve was opened and water was discharged directly into the opaque amber 1 L bottles.

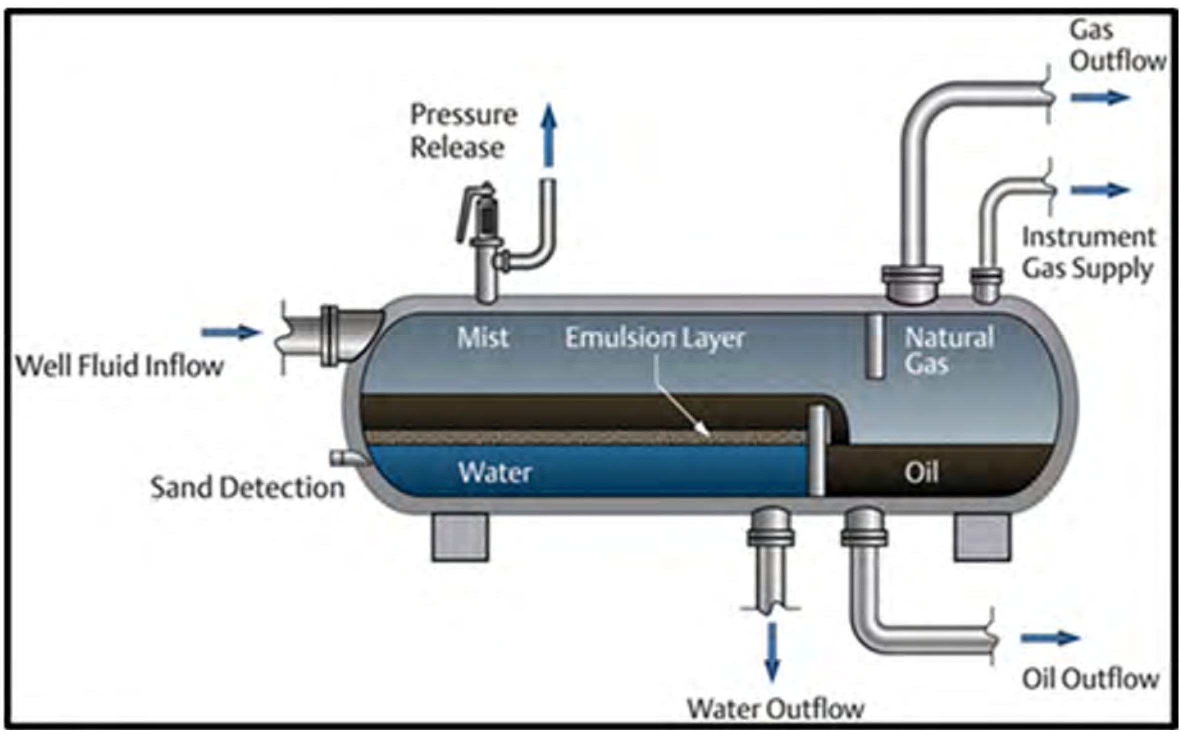
In all cases, two 1 L opaque amber bottles of sample were collected from each well. The bottles were filled up to the very top with reservoir water to ensure no air could get trapped in the top. A cap was then screwed on, and the cap was sealed with electrical tape. An E3 custody seal was affixed to the bottle and cap to ensure no sample tampering (Figure 9-3).

These bottles were kept in a cooler with their chain of custody documents and delivered to the laboratory for testing once the sampling program was complete.

Figure 9-1: Sample Collection at Wellhead

Note: Photography by Bureau Veritas, 2021. Left: Bureau Veritas employee sampling from access port into 4 L plastic container. Right: Decanting brine sample from bottom of 4 L container.

Figure 9-2: Schematic of Test Separator



Note: Figure from Emerson (2020).

Figure 9-3: Sample Collection at Test Separator

Note: Photography by Bureau Veritas, 2021. Left: Bureau Veritas employee collecting sample from test separator access port. Right: Sealed well samples.

9.4.3 Large Volume Samples

Large volume samples (3–20 m^3) were collected using the same methods outlined above from 3-phase separators in 2018 and 2019. With large volume collections, Leduc brine was treated directly to remove hydrogen sulfide using AMGAS proprietary CLEAR technology and stored in 1 m^3 totes.

Large scale brine collection was also completed in 2023 for E3's direct lithium extraction field pilot (~1,200 m^3 of brine was pumped to 10 tanks and sweetened using AMGAS proprietary CLEAR technology). This brine was primarily used for direct lithium extraction testing on site.

9.4.4 Repeat Sampling

A total of 55 unique locations, either different wells or different depth intervals within the same well, were collected from the Bashaw District in the period 2017 to 2023. Out of the 55 locations, some have been sampled multiple times throughout that timeframe to maintain a record and understanding of brine consistency over time. In total, 102 samples were taken (including repeat samples) over the Bashaw District.

9.5 Hydrogen Sulfide

Sour gas (hydrogen sulfide) was present at all the sites sampled. For this reason, safety precautions were taken by field samplers, including wearing hydrogen sulfide sensors, and always having two personnel on site for sample collection. Where the hydrogen sulfide content was high (>10 ppm), self contained breathing apparatus with an oxygen tank was used to ensure the field samplers were safe.

9.6 Well Additives

A list of well additives, such as demulsifier, corrosion inhibitor and paraffin inhibitor, was obtained for each wellsite to rule out potential lithium contamination. No sources of lithium contamination were identified after a review of the safety data sheets.

9.7 Exploration Potential

E3's mineral tenure includes rights to all brine-hosted minerals from surface to the basement within those rights. Exploration for lithium from other lithological units outside of the Leduc Formation is an E3 exploration focus, with exploration ongoing in these units. E3 has identified elevated lithium concentrations in the Nisku Aquifer, which overlies the Leduc Formation (E3, 2024).

9.8 QP Comments on Section 9

The QP considers that the field sampling program samples were representative of the reservoir sampled. No factors are known to the QP that could have caused sample biases.

The sample data can be used in exploration programs and in Brine Resource estimation.

10.0 DRILLING

10.1 Introduction

E3 drilled two wells and a third well was acquired through another operator in the fall of 2022, with the intention to test the Leduc brine for lithium:

- E3 well, MIM Stewart 1-16-33-27W4: total depth 2,670.0 m; E3 drilled and completed;
- E3 well, 102/16-16-031-27W4: total depth 2,722.3 m; E3 drilled and completed;
- Third party well; 100/04-27-033-28W: total depth 3,061.0 m; E3 completed.

All three wells were located in the southern portion of the Bashaw reef complex (Figure 10-1). A summary of the work program is provided in Figure 10-2, showing the lithium sampling results.

10.2 Drilling Supporting Brine Resource Estimation

Drilling supporting the Brine Resource estimate is discussed in Section 14.

10.3 Drill Methods

Table 10-1 summarizes the drill contractors and drill rigs used, where known, and the drill hole diameters.

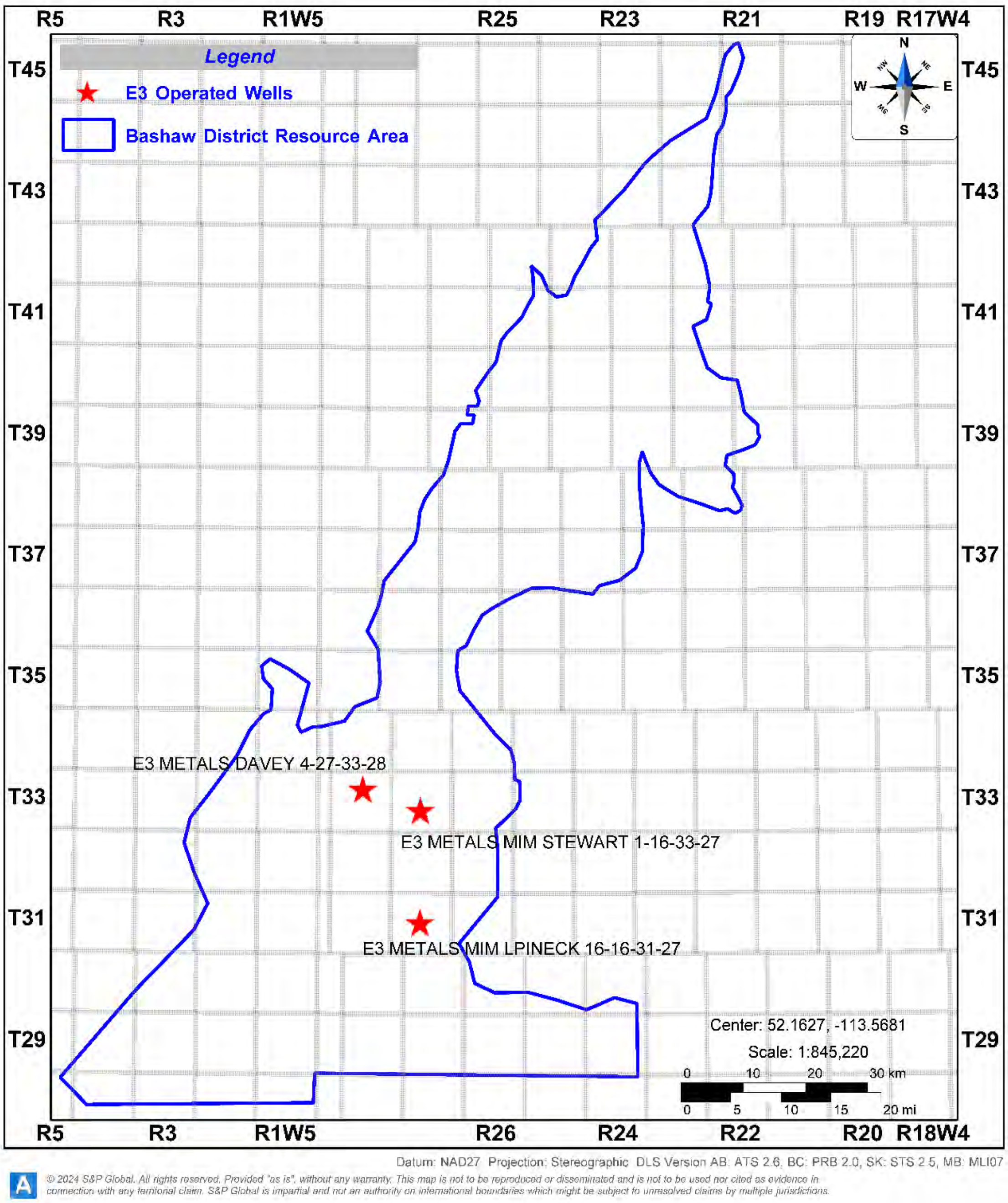
10.4 102/01-16-033-27W4 (E3 Drilled and Completed)

A vertical well, E3 Metals MIM Stewart 1-16-33-27W4 commenced on June 23, 2022 and reached a total depth of 2,670.00 m on July 7, 2022. The top of the Leduc reservoir was intersected at a measured depth of 2,415.36 m.

Three cores were cut at this well, a total of 36.9 m in core between a measured depth of 2,490–2,589 m along the wellbore. The total thickness of the Leduc reservoir in this well was 210.6 m.

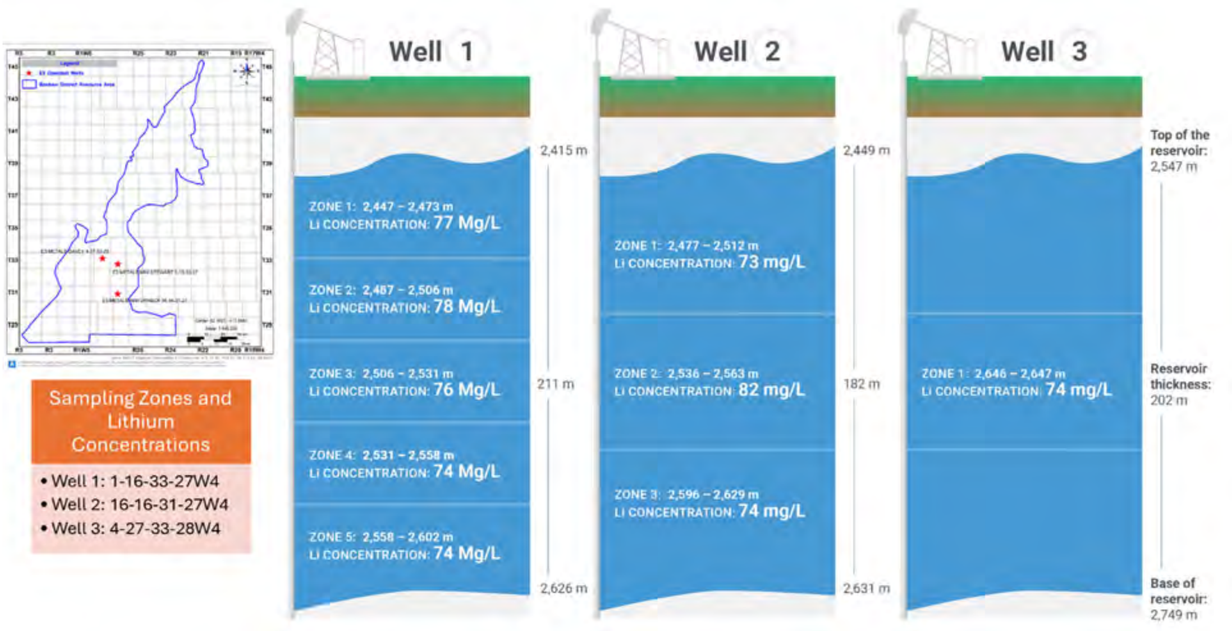
The well set intermediate casing point at 2,437.8 m measured depth, the top of the Leduc Formation. Below the intermediate casing point, a system of tubing strings with six shiftable sleeves placed between packers and joints manufactured by NCS Multistage was installed in the hole (Figure 10-3). One sleeve was placed in the Cooking Lake Formation, and the other five sleeves were in the Leduc Formation.

Figure 10-1: E3 Operated Wells, Drilling And Completions



Note: Figure prepared by E3, 2024.

Figure 10-2: 2022–2023 Drill Program Well Locations and Lithium Concentration Results

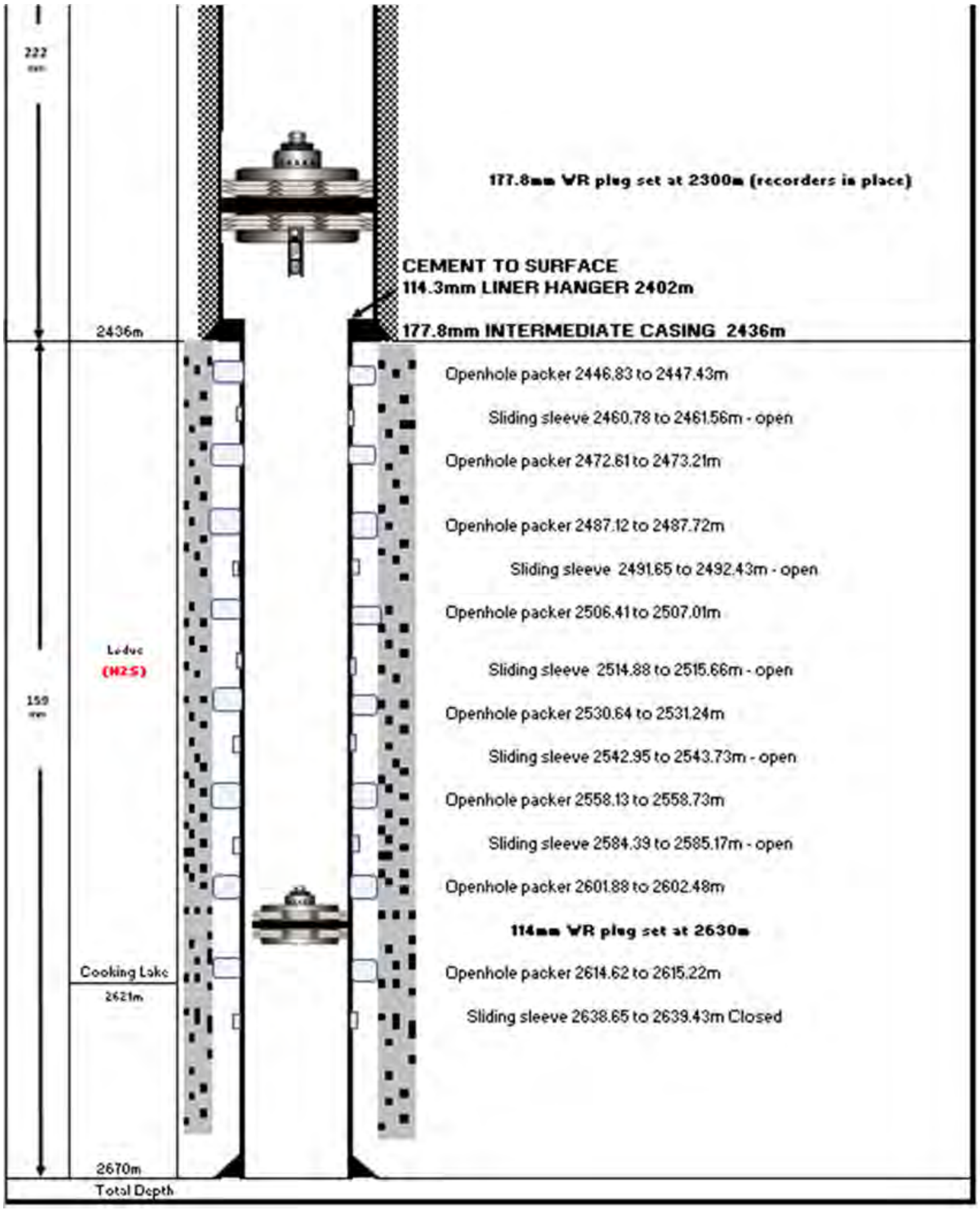


Note: Figure prepared by E3, 2024.

Table 10-1: Drill Methods and Contractors

Location	Contractor and Rig	Hole Diameters
102/01-16-033-27W4	Frontier Project Solutions Ironhand #9	Surface hole/casing: 311.2 mm/244.5 mm Intermediate hole/casing: 222.3 mm/177.8 mm Main hole/casing: 156 mm/114.3 mm
102/16-16-031-27W4	Frontier Project Solutions Ironhand #9	Surface hole/casing: 311.2 mm/244.5mm Intermediate hole/casing: 222.3 mm/177.8 mm Main hole/casing: 156 mm/114.3 mm
100/04-27-033-28W4	Unknown; E3 acquired post-drill and complete	Surface hole/casing: 311.2 mm/244.5 mm Intermediate hole/casing: 222.3 mm/177.8 mm Main hole (no casing): 156 mm

Figure 10-3: Completion Diagram/Schematic For 102/01-16-033-27W4



Note: Figure prepared by E3, 2024.

A service rig was on location on July 10, 2022. Sampling operations commenced on August 1, 2022, when one brine sample was taken from the Cooking Lake Formation, and five samples were taken from the Leduc Formation. Sliding sleeves were articulated using an NCS bottom hole shifting assembly, isolating the sampling interval by only opening the port to be sampled and sealing the annular space outside of the sampling sleeve with inflatable packers. Formation fluid was swabbed from each interval until the total dissolved solids content of the fluid stabilized around 200,000 mg/L. This total dissolved solids reading was a benchmark for interpreting the sample was representative formation fluid.

Samples were collected from a testing vessel at surface, where the downhole fluids were produced to, prior to following the standard operating procedures described in Section 11.

Following sampling, a flow test (production then injection) was performed on this well.

10.5 102/16-16-031-27W4 (E3 Drilled and Completed)

A vertical well, 102/16-16-031-27W4, commenced on July 23, 2022 and was rig released on August 6. The top of the Leduc reservoir was intersected at a measured depth of 2,450.5 m and the total depth of the well was reached at 2,722.3 m.

The intermediate casing point was set at a measured depth of 2,469 m (Figure 10-4). Six sleeves were placed along the liner, with packer and joint separation; five sleeves were placed in the Leduc Formation, and the sixth sleeve in the underlying Cooking Lake and Beaverhill Lake Formations.

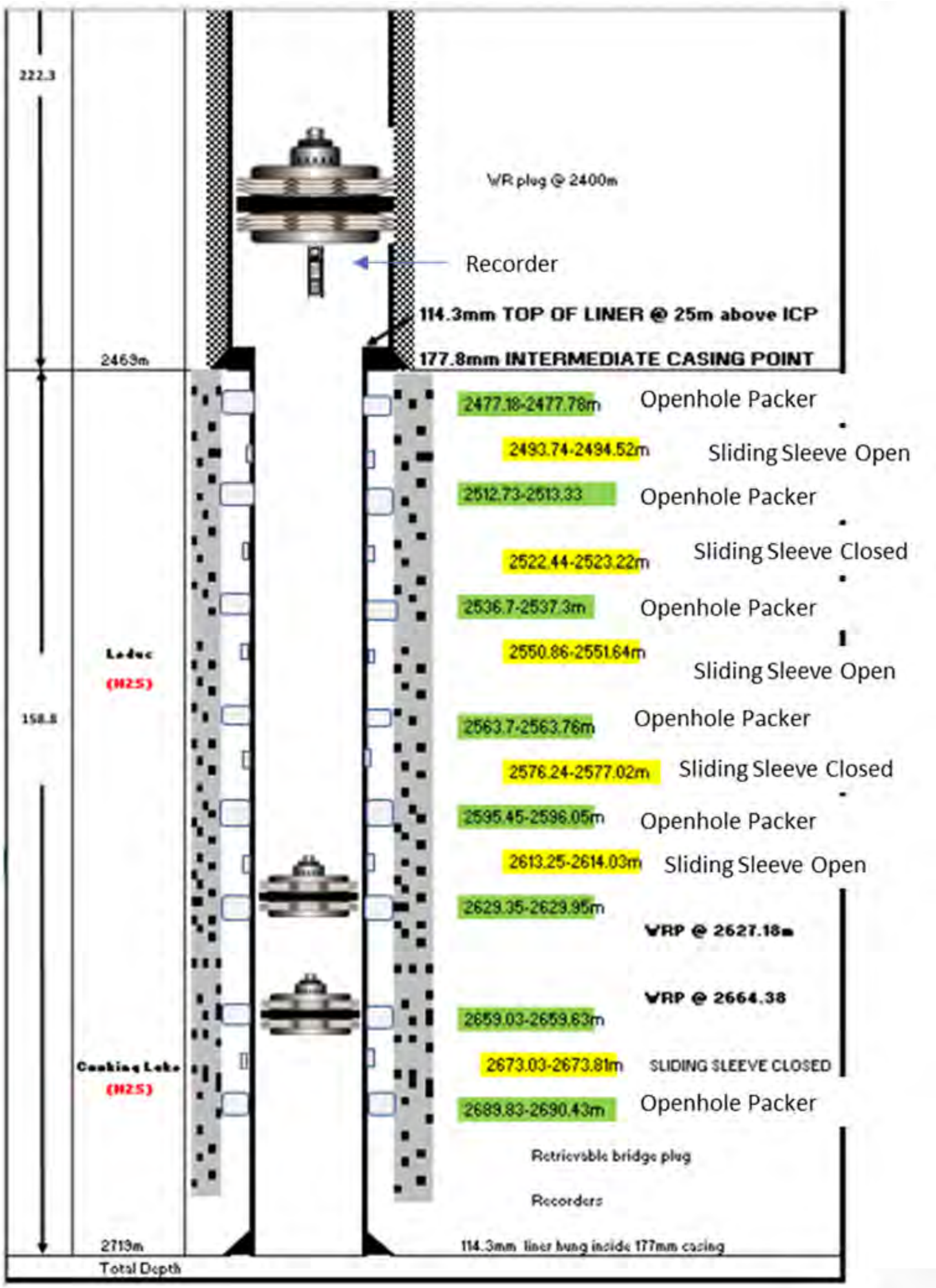
Sampling operations commenced September 6, following the same procedure described for 01-16-33-27W4, but not all intervals were sampled as confidence in the vertical grade distribution was increased following the results from the first well. Three sleeves in the Leduc Formation were sampled, at depths to represent the base, middle and top of the Leduc reservoir (Figure 10-4).

10.6 100/04-27-033-28W4 (Third Party Drill; E3 Completed)

The 100/04-27-033-28W4 was a wildcat exploratory well drilled and completed in October 2021 by Aspenleaf Energy. The target objective was the Beaverhill Lake Group, a zone below the Leduc Formation. This well is deviated; the top of the Leduc Formation intersected a true vertical depth at 2,546.7 m and the base of the Leduc, the Cooking Lake Formation is 2,749.1 m, therefore the true vertical thickness of the Leduc Reservoir is calculated to be 202.4 m at this wellbore.

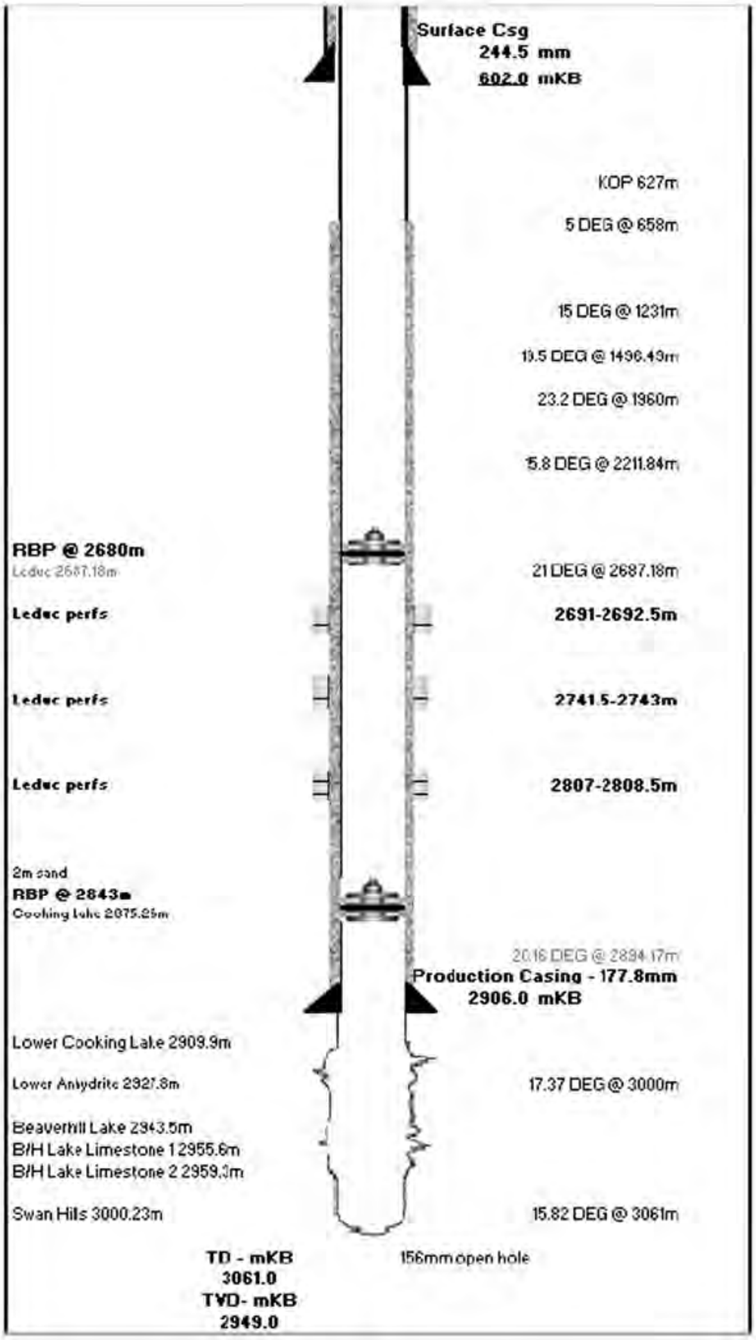
Since this well was targeting a deeper objective, the ICP was set deeper than the Leduc Formation (Figure 10-5).

Figure 10-4: Completion Diagram/Schematic For 102/16-16-031-27W4



Note: Figure prepared by E3, 2024. Respective 'open' sleeves, designate which intervals samples were retrieved from.

Figure 10-5: Completion Diagram/Schematic For 100/04-27-033-28W4



Note: Figure prepared by E3, 2024. The well was perforated in three zones, and one sample was collected from the middle zone (2,741.5–2,743 m).

E3 perforated the casing to obtain samples in the Leduc Formation. The well exhibited scaling and corrosion in the casing, as well as significant skin damage that occurred during drilling. Therefore, only one of the perforation intervals was sampled, at a depth from 2,646.04–2,647.44 m true vertical depth. E3 is evaluating options for future re-entry and clean-up of this wellbore for additional sampling.

10.7 Logging

Standard geophysical log suites were run for the E3 drilled and completed wells, including: gamma ray, caliper, neutron, density, resistivity, and cement bond logs. The drill cuttings samples obtained during mud rotary drilling were also observed and logged by a wellsite geologist to make a strip log during the drilling of the well.

10.8 Recovery

The core recovery where core was collected in the Leduc interval was approximately 85%. However, the full thickness of the formation was not sampled. Because mineralization is evaluated from the fluid not the rock, core sampling is only required to evaluate porosity and permeability. These parameters are also evaluated using geophysical logs and production testing and therefore core recovery is not deemed a critical factor affecting the resource estimate.

10.9 Collar Surveys

A collar locator logging tool was used to identify collar locations. The tool consists of a set of magnetic coils that detect changes in the magnetic field cased by the presence of the metallic collars.

10.10 Downhole Surveys

During drilling, directional tools measure the well bottom-hole location using sensors behind the drill bit which measure inclination and azimuth. The data are transmitted to surface using electromagnetic signals that are interpreted in real time to guide the well trajectory. Post-drill, directional surveys were run on all three locations, to total depths, using advanced directional sensors and broad frequency electromagnetic signals.

10.11 Sample Length/True Thickness

The dip in the study area is low (approximately 0.6 degrees to the southwest), and then therefore vertically drilled wells intersect the formation at an angle approximating true thickness. However, sample length is not relevant to the brine-hosted lithium mineralization type as the brine is dissolved in a fluid that moves through the reservoir. Reservoir characterization leverages logging data, which gathers data across the entire drill depth. The drilling described here sampled across the entire thickness of the zone of interest.

10.12 QP Comments on Section 10

The QPs note that:

- The drilling methods employed are suitable for evaluating the formation and are consistent with industry standard techniques used in the oil and gas industry. Challenges were encountered when drilling including hydrogen sulphide, scaling and corrosion in the casing, and skin damage, resulting in a calculated maximum rate rather than a measured maximum rate;
- Core recovery was acceptable, but core was only recovered over a sub-interval of the full reservoir. However, core is not the most critical geological data input to the Brine Resource estimate and full coverage of the formation was provided by geophysical logs and fluid samples;
- E3's exploration drilling provided suitable data to characterize the interior lagoonal facies of the Bashaw Reef trend including core, geophysical logs of porosity, vertically-discretized brine samples, and production test data. These data are suitable to inform Brine Resource and Brine Reserve estimation.

11.0 SAMPLE PREPARATION, ANALYSES, AND SECURITY

11.1 Sampling Method

The general sampling procedure was consistent for samples collected either from existing oil and gas infrastructure (Section 9) or dedicated exploration wells installed and sampled by E3 (Section 10).

All samples were collected into 1 L opaque amber bottles. The bottles were filled to the top to ensure no air was trapped at the top. The cap was screwed on and then sealed with electrical tape. Each bottle was labeled with the unique well identifier, sample interval depth, date, and an E3 custody seal was applied for security.

11.2 Sample Preparation and Analytical Laboratories

Samples were submitted either to Bureau Veritas Laboratories in Red Deer(Bureau Veritas Red Deer; where the field staff that collected brine samples were stationed), Edmonton (Bureau Veritas Edmonton, used for degassing, routine water analysis, total suspended solids analysis; petrographic analysis), or Calgary (Bureau Veritas Calgary, used for degassing, routine water analysis, and trace metal analysis). AGAT Laboratories in Calgary (AGAT) and the SGS geochemical and mineral process laboratories Lakefield, ON (SGS Lakefield), and the SGS environmental laboratory in Burnaby (SGS Burnaby) were also used for selected analytical and processing techniques.

Each of these laboratories are accredited by the Canadian Association of Laboratory Accreditation Inc. as meeting general requirements for the competence of testing and calibration laboratories. The laboratories are independent of E3.

11.3 Sample Preparation and Analyses

In the laboratory, samples were first degassed to primarily get rid of hydrogen sulfide. Samples from the same unique well identifier were combined into a large beaker in a fume hood for hydrogen sulfide degassing. A reference beaker of water was placed beside each sample to measure the degree of evaporation over the degassing period. This evaporation was found to be <1% for all samples and was reported along with the lithium result.

After hydrogen sulfide removal, the larger sample was stirred using a stir-bar for at least one minute prior to subsampling to ensure sample homogeneity. Then 100 ml or 125 ml of sample was discharged into two opaque amber glass or high-density polyethylene bottles for trace metals testing at SGS Lakefield (assay laboratory) and Bureau Veritas Calgary where routine water analyses were run, providing duplicate testing to verify trace metal results. The degassing laboratory (Bureau Veritas Edmonton, Bureau Veritas Calgary, or SGS Lakefield) packed and shipped samples to their respective destinations with chain of custody documents, as the trace metal lab testing facilities are not equipped to handle sour samples.

Samples received at the individual laboratories were vigorously mixed and a subset of sample was placed in a digestion tube. All samples taken prior to 2022 were first digested with hydrogen peroxide, and then digested again with a mixture of nitric acid and hydrochloric acid. The purpose of the hydrogen peroxide digestion was to break down humic acid and various organics in the sample that are believed to interfere with the lithium measurement. Third-party operator samples collected in 2022–2023, did not undergo a double digestion and were only digested once with the nitric acid and hydrochloric acid step.

Post-digestion, samples were then diluted and run through an inductively coupled plasma–optical emission spectrometry (ICP–OES) machine for trace metal analysis. Samples collected from the three E3 wells had trace metals measured by SGS Lakefield. The samples were diluted with 20% HCl for the ICP-OES and 2% HCl for the inductively coupled plasma–mass spectrometry (ICP-MS) method. A combination of both practices is used for the 30 trace metal analyses. A list of the analytes and the corresponding detection limits is provided in Table 11-1.

11.4 Quality Assurance and Quality Control

E3's minimum standard for QA/QC is to analyse one standard for every 10 samples. Since 2022, E3 has run one standard, one duplicate, and one blank for every 10 samples.

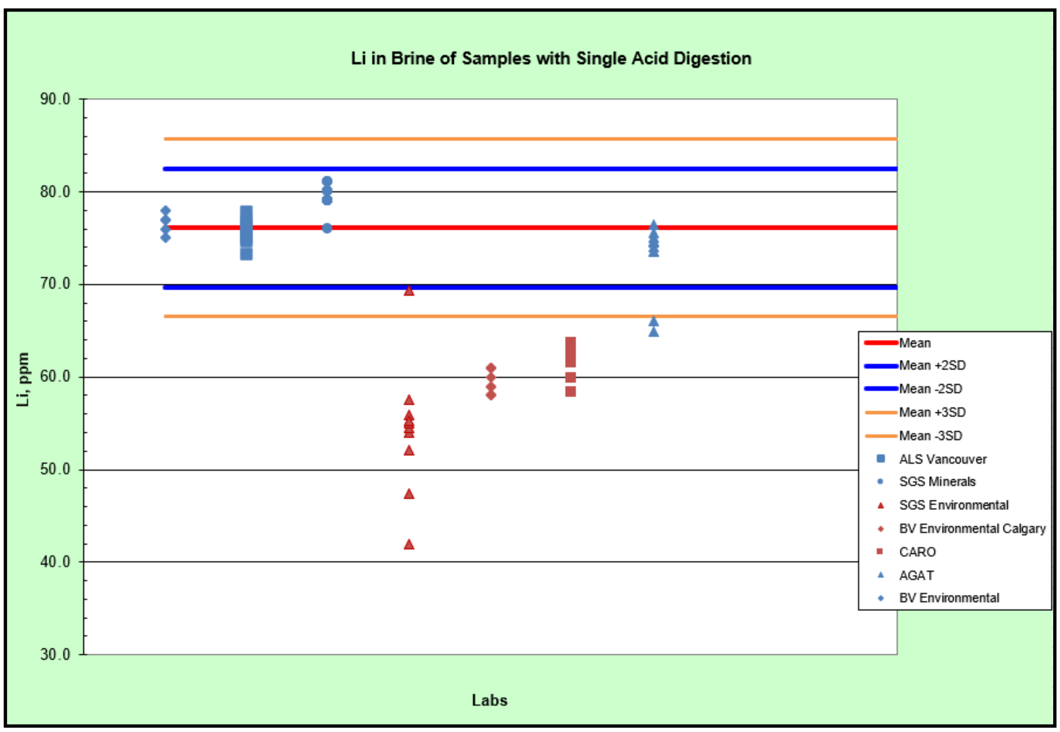
11.5 Certified Reference Material Verification

A round robin was completed in Q4 2021, as a process to get a certified reference material (standard) lithium concentration for resource brine from the 100/10-29-030-27W4/00 well. A total of 70 samples of produced Leduc brine were sent to a total of seven laboratories. Laboratories included Bureau Veritas Calgary; Bureau Veritas Mineral Laboratory (Vancouver); ALS Environmental (Vancouver); CARO Analytical Services (Vancouver); SGS Minerals (Lakefield); SGS Environmental (Lakefield); and AGAT. Ten samples were sent to each of these laboratories, and samples were processed using a double digestion- first digested with hydrogen peroxide, and then digested again with a mixture of nitric acid and hydrochloric acid; and standard single digestion for ICP with nitric acid and hydrochloric acid mixture (Figure 11-1).

Table 11-1: Multi-Element Package Element Suite and Detection Limits

Element	Lower Detection Limit (ppm)	Element	Lower Detection Limit (ppm)	Element	Lower Detection Limit (ppm)
Ag	0.001	Cu	0.008	Pb	0.002
Al	0.2	Fe	0.2	Sb	0.004
As	0.05	K	1	Se	0.05
Ba	0.007	Li	2	Sn	0.01
Be	0.002	Mg	0.07	Sr	0.002
Bi	0.003	Mn	0.04	Ti	0.02
Ca	0.9	Mo	0.003	Tl	0.002
Cd	0.001	Na	2	V	0.009
Co	0.003	Ni	0.1	Y	0.001
Cr	0.01	P	5	Zn	0.01

Figure 11-1: Lithium Concentrations from Laboratory Results Run With A Single-Standard Digestion



Note: Figure prepared by Dr. Barry W. Smee , 2022

Of the seven laboratories used, three (SGS Environmental, BV Environmental and CARO) did not use ICP–OES, instead they used ICP–MS which does not accurately measure lithium concentration. Due to this inconsistency, lithium concentration results from these three laboratories were not used to determine the values of the standard.

Out of the seven laboratories, only three were able to run samples with the double digestion (Figure 11-2). Of the three laboratories, only AGAT used the preferred method of analysis-direct aspiration of the brine into an ICP–OES. The little variation in lithium concentrations between the AGAT samples ran with a single standard digestion and those run with a double digestion showed this extra digestion step is unnecessary for the Leduc brine (sourced from well 100/10-29-030-27W4/00).

In summary, the certified mean of 76.1 mg/L was signed off and assigned, largely based on the single digestion sample subset, of the four laboratories that used the appropriate methods for analyses. This certificate was signed off by a recognized sampling expert, Dr. Barry W. Smee, P.Geo, in March 2022. Results are discussed in the following sub-section.

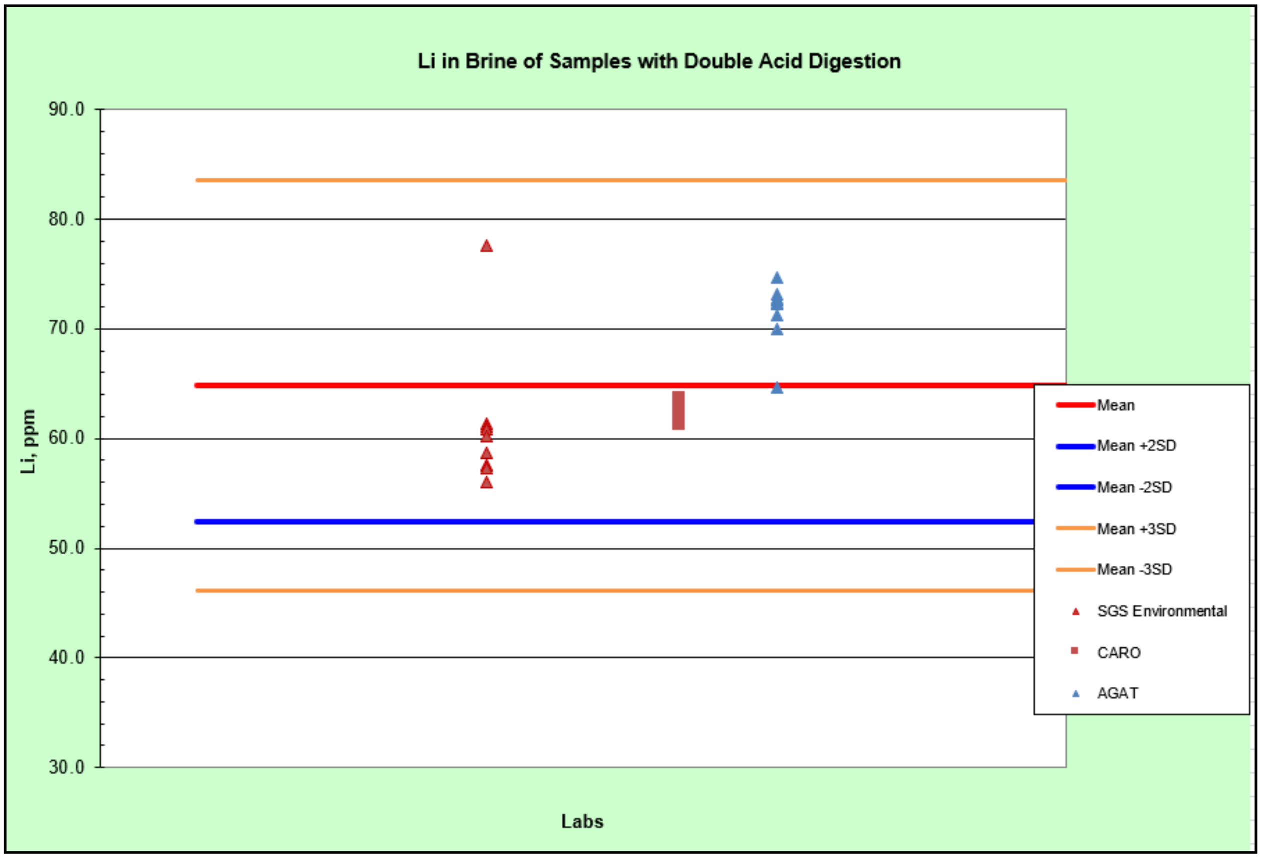
11.6 Program Results

A total of 102 Leduc brine samples were collected by E3 across the Bashaw District (Figure 11-3) at the Report effective date.

E3 excluded publicly-available brine data from estimation support because it is unclear if the samples were subject to an equivalent of E3's standard operating procedure or if a chain of custody to ensure sample security was used.

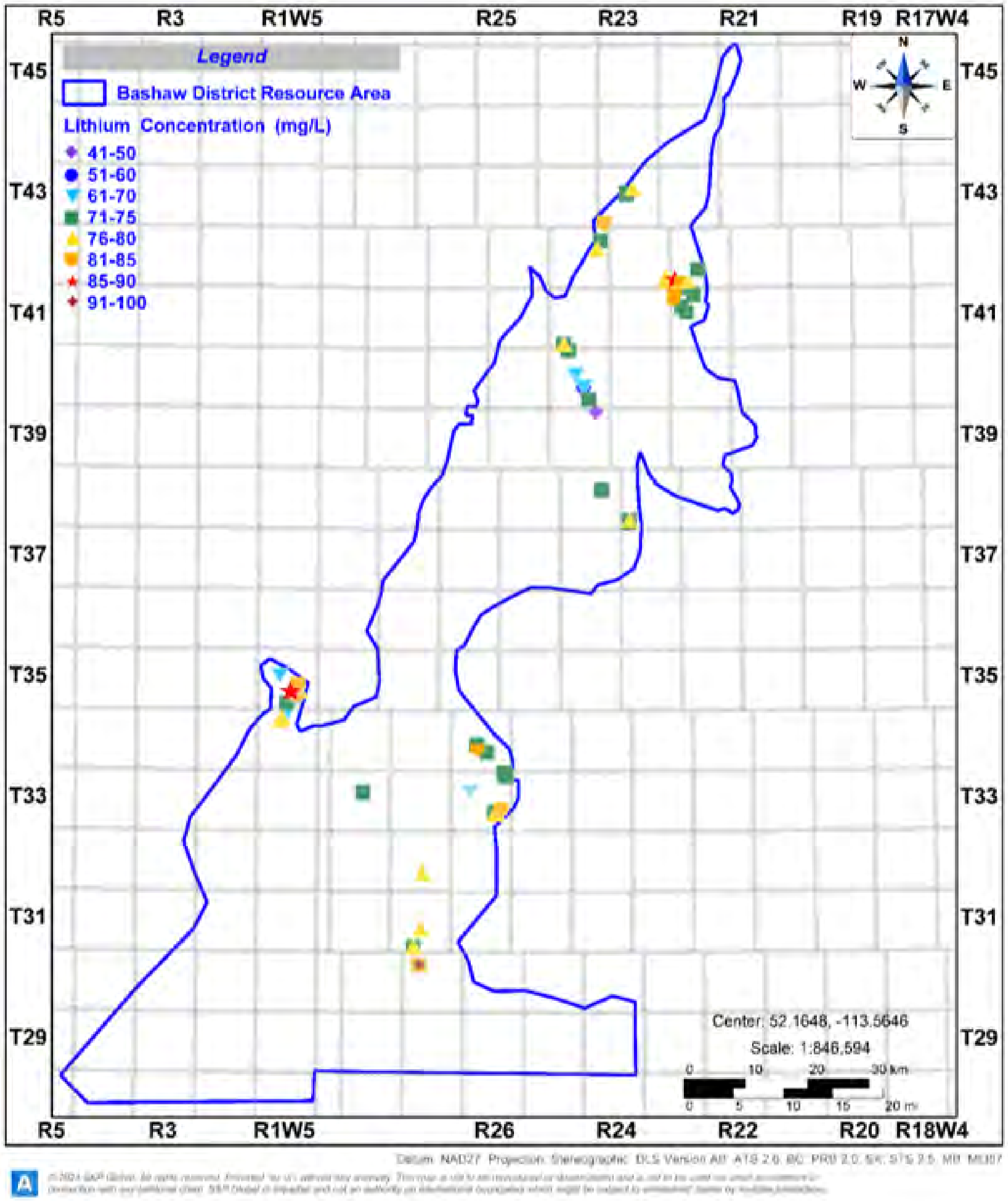
Of the sample data contained in this Report, a subset of these samples come from the same well (55 unique locations sampled over the Bashaw District). At each well location, there may be different vertical intervals of the Leduc Aquifer that were sampled (six intervals at 01-16-033-27W4 and three intervals at 16-16-031-27W4) and there are also samples that were collected from the same well and interval over time (47 repeat samples). The methodology for evaluating the lithium concentration at each location has changed in this technical report as compared to historical technical reports. In past analysis, samples were aggregated at each location including temporally different samples and those collected at different depths vertically in the reservoir. In this updated analysis, vertically different samples were treated as unique samples so that vertical heterogeneity within the reservoir could be evaluated. For intervals with multiple samples over time, a mean value was calculated after a qualitative review that the samples had low variance in the temporal scale.

Figure 11-2: Lithium Concentrations from Laboratory Results Run With A Double Acid Digestion



Note: Figure prepared by Dr. Barry W. Smee , 2022

Figure 11-3: Lithium Results Across Bashaw District



Note: Figure prepared by E3, 2024.

Based on the sampling results, the Leduc Formation is enriched in lithium in sampled wells across the Bashaw District, and the data demonstrate consistency throughout both horizontally and vertically. Table 11-2 shows the minimum, maximum and P50 values for lithium grade across the Bashaw District. Figure 11-4 shows the histogram of the sampling data.

Of the 104 samples reviewed, 102 were considered valid, based on a comparison between calculated total dissolved solids of the brine and lithium concentrations (Figure 11-5). The low outlier sample, containing 130,000 mg/L total dissolved solids, has a complicated well completion history including comingled production with the Nisku Formation. As such, the sample was excluded from the analysis as the total dissolved solids content marks it as unrepresentative of the Leduc Formation.

The average brine chemistries from routine and trace metals scan analysis in the Bashaw District are presented in Table 11-3.

11.7 Temporal Variation

Sampling includes samples from 44 individual wells, with four or more repeat samples collected at several locations. A graphical summary of lithium concentration measurements in three wells with repeat samples is shown in Figure 11-6. All analytical results fall within acceptable limits as prescribed by the laboratory. These graphs suggest lithium concentrations remain steady in a relatively narrow P90 to P10 distribution over time in the Bashaw District.

11.8 Density Determinations

Elemental lithium was measured from brine samples in mg/L. Conversion between elemental lithium and lithium carbonate equivalent and lithium hydroxide monohydrate tonnes was based on the information summarized in Table 11-4.

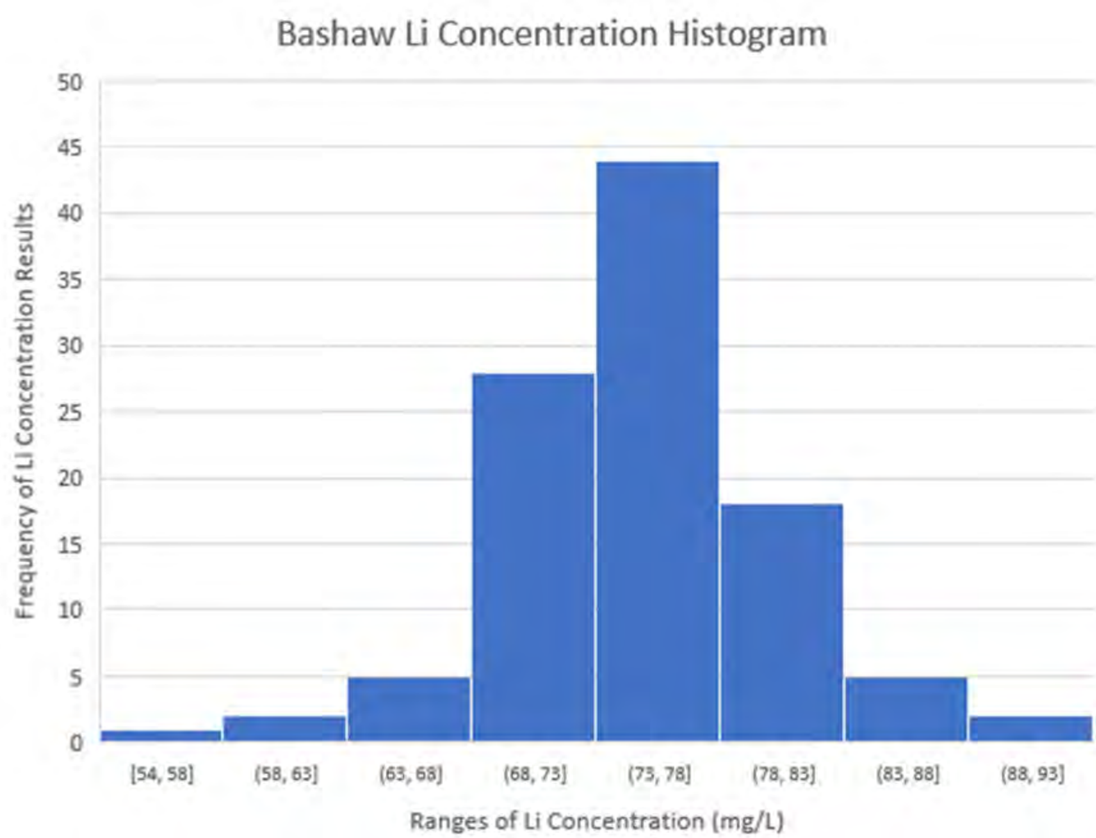
11.9 Sample Security

Samples were kept secure in a cooler with their chain of custody information and delivered to the relevant laboratory.

Table 11-2: Sampling Results from E3's Programs (2017–2023)

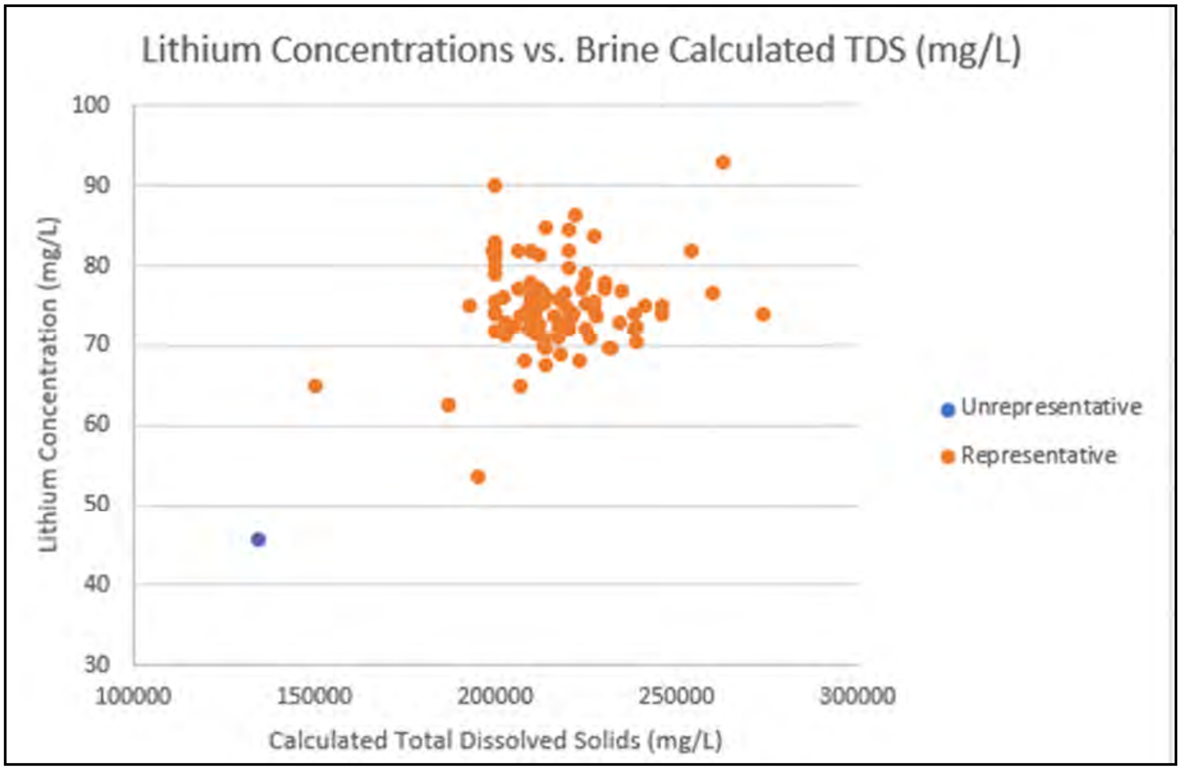
Resource Area	Min Li (mg/L)	P50 Li (mg/L)	Max Li (mg/L)
Bashaw District	53.5	75.5	93

Figure 11-4: Bashaw District Lithium Concentration Histogram



Note: Figure prepared by E3, 2024. Averaged value for sampled interval per wells with repeat samples.

Figure 11-5: Sampled Lithium Concentrations Plotted Against Total Dissolved Solids



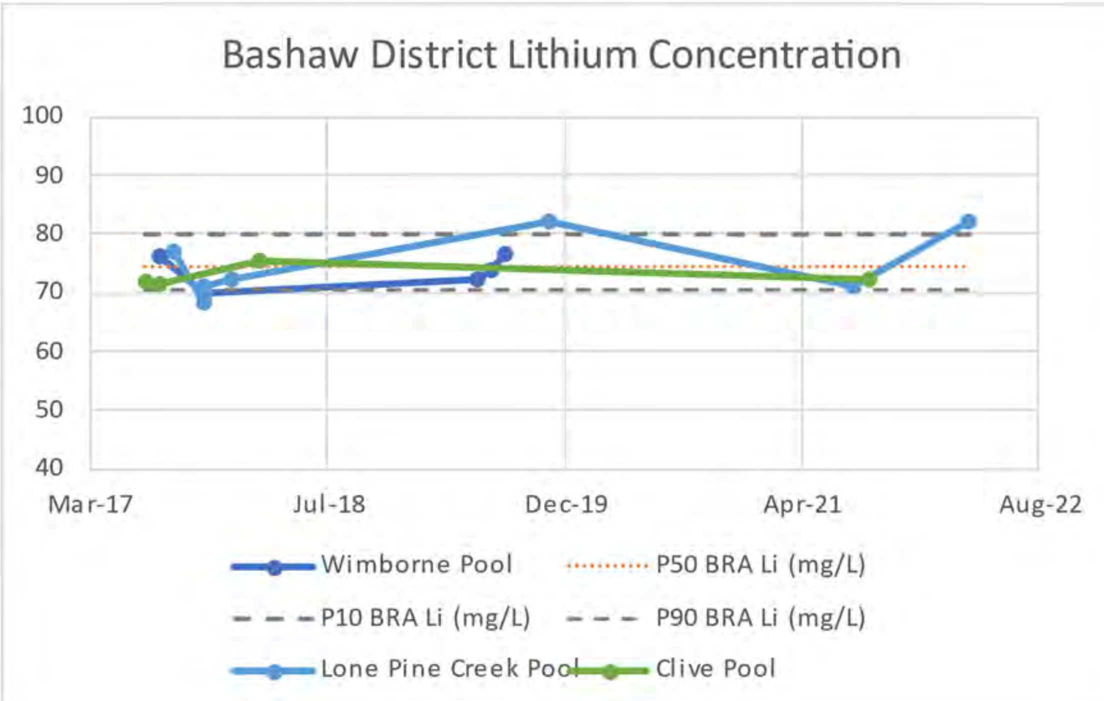
Note: Figure prepared by E3, 2024.

Table 11-3: Average Chemical Analyses Across the Bashaw District

Method	Element/Analyte	Units	P50 Lithium
Trace metals analysis	Total arsenic	mg/L	<2
	Total barium	mg/L	1.45
	Total boron	mg/L	274
	Total lithium	mg/L	74.65
	Total manganese	mg/L	0.17
	Total silicon	mg/L	11.6
	Total strontium	mg/L	956
	Total calcium	mg/L	21,900
	Total magnesium	mg/L	2,950
	Total sodium	mg/L	49,000
	Total potassium	mg/L	6,530
Routine water analysis	pH		7.03
	Alkalinity *	mg/L	458
	Bicarbonate	mg/L	570
	Conductivity	µS/cm	333,000
	Dissolved chloride	mg/L	133,000
	Fluoride	mg/L	4.00
	Dissolved sulphate	mg/L	379.40
	Dissolved calcium	mg/L	21,100
	Dissolved magnesium	mg/L	2,910
	Dissolved sodium	mg/L	49,000
	Dissolved potassium	mg/L	6,130
	Dissolved iron	mg/L	<2
	Dissolved manganese	mg/L	0.15
	Calculated total dissolved solids	mg/L	213,600
	Sodium adsorption ratio	mg/L	83.20
	Hardness	mg $CaCO_3$/L	64,700
	Total Suspended Solids	mg/L	333

Note: *Total as $CaCO_3$.

Figure 11-6: Lithium Concentrations in the Bashaw District Over Time



Note: Figure prepared by E3, 2024.

Table 11-4: Conversion Considerations and Factors, Volume to Tonnage

	LCE Conversion Factor: 5.323	**Lithium Hydroxide Monohydrate Conversion Factor: 6.046**
Lithium density: 534 kg/m^3 Lithium molecular weight: 6.941 g/mol	Li_2CO_3 molecular weight: 73.891	$LiOH.H_2O$ molecular weight: 41.96

Note: LCE = lithium carbonate equivalent.

11.10 QP Comments on Section 11

The QP verified that the data presented in this section resulted from adequate sample preparation, security and analytical procedures. Data are suitable to support Brine Resource and Brine Reserve estimation.

The laboratory analysis work completed by E3 demonstrates that the range in lithium concentrations from the samples collected is narrow and that the majority of samples fall within a range of 15 mg/L which is within a similar range of variability of the analysis of the certified reference material. This suggests that the variability of lithium in the samples collected is very low despite coming from different lateral and vertical areas of the reservoir.

12.0 DATA VERIFICATION

12.1 Data Verification by Qualified Persons

The Qualified Persons verified the data that forms the basis of the 2024 PFS, including sampling, analytical, and test data.

12.2 Mr. Daron Abbey

Mr. Abbey verified the data used to estimate the Brine Resource volumes, including:

- E3's 2017–2024 sampling programs (lithium concentrations);
- Public well data such as logs, core analysis, and drill stem tests that were interpreted to evaluate formation depths and thicknesses, geological facies, lithology, total and effective porosity, and permeability;
- E3's 2022 evaluation well program including production tests;
- Core analysis for total porosity, effective porosity and permeability; facies descriptions;
- Brine chemical analysis;
- Confirmation of reservoir lithology and pressure.

The data were considered acceptable for use in Brine Resource estimation.

12.3 Mr. Alex Haluszka

Mr. Haluszka verified the data used to estimate the Brine Resource volumes, including:

- E3's 2017–2024 sampling programs (lithium concentrations);
- Historical production and injection volumes of hydrocarbons and brines (regional pressure measurements, rate data);
- Public well data such as logs, core analysis, and drill stem tests that were interpreted to evaluate formation depths and thicknesses, geological facies, lithology, total and effective porosity, and permeability;
- E3's 2022 evaluation well program including production tests;
- Core analysis for total porosity, effective porosity and permeability; facies descriptions;

- Brine chemical analysis;
- Confirmation of reservoir lithology and pressure.

The data were considered acceptable for use in Brine Resource estimation.

12.4 Ms. Meghan Klein

Ms. Klein verified the data used to estimate the mineral reserve volumes, including: geostatistical static model; dynamic model; reservoir simulation; capital and operating cost estimates; price forecasts; market studies; and economic model.

The data were considered acceptable for use in Brine Reserve estimation and the economic analysis that supports the Brine Reserves.

12.5 Mr. Antoine Lefaivre

Mr. Lefaivre verified the data used to validate the mineral processing, recovery methods, and project infrastructure, including: laboratory and field test results; analytical methods; process calculations; block flow diagrams; process flow calculations; facility design; equipment specifications; and energy, water, and process material requirements.

The data are acceptable for use in Brine Resource and Brine Reserve estimates and can be used for process facility design.

12.6 Mr. Keith Wilson

Keith Wilson P. Eng verified the data used to validate the environmental studies, permitting, and social/community impact, including: regulatory requirements; CO_2e emissions calculations; remediation and reclamation costs.

The data are acceptable for use in Brine Resource and Brine Reserve estimates.

12.7 Lithium Grade Sampling

One component of the quality assurance program was for a QP to witness sample collection in the field.

Mr. Haluszka, having reviewed the field sampling standard operating procedure and the laboratory testing standard operating procedure developed by E3 to achieve consistent and accurate sample collection and analysis, witnessed the sampling and authenticated the standard operating procedures and chain of custody, for the 2022 sampling program and the 2022 drill program.

Bureau Veritas employees collected samples from a 3-phase test separator facility on April 28, 2022. Mr. Haluszka observed that Bureau Veritas employees demonstrated a competency of the E3 standard operating procedures and executed sampling accordingly. The site was in the southern area of the Bashaw District, within the Lone Pine Creek hydrocarbon pool, and the produced water sampled flowed from the 100/10-29-030-27W4. Samples were delivered to AGAT for degassing, trace metal and routine water analyses by a courier (Rebel Hotshot Courier Services) upon the completion of the sampling program.

Mr. Haluszka reviewed the quality assurance/quality control results provided by E3 and reviewed the reports provided for each lithium sample by the laboratory. He is satisfied that data presented in this Report are adequate for the purposes of estimating Measured and Indicated Brine Resource volumes.

Starting in 2019, Bureau Veritas Laboratories (then Maxxam Laboratories) and E3 worked with the same field staff for ongoing sampling programs.

There are a series of historical sampling results throughout the mineral property. These historical data were collected by Lyster, et al. (2021). The specific circumstances under which the samples were taken are unknown and accordingly these data were not included in the resource estimation.

12.8 Flow Test

Mr. Alex Haluszka witnessed a flow test during a site visit on September 15, 2022, and reviewed the validated and authenticated report provided by IHS Markit. The site visit included observation of the flow rates, discussions with the third-party Schlumberger field engineer who was operating the electric submersible pump, and discussions with Grant Production Testing personnel who were providing quality control and assurance on the rate measurements.

The flow test analysis was independently validated by Mr. Haluszka, who undertook an independent analysis of the data using hydrogeological pressure transient data analysis software.

13.0 MINERAL PROCESSING AND METALLURGICAL TESTING

13.1 Introduction

Testwork for the Clearwater Project was conducted by, or supervised by SGS Lakefield, Bureau Veritas Calgary and Bureau Veritas Edmonton, as well as vendor and E3 in-house laboratories and piloting facilities during the period of 2019–2024 and remains ongoing. To date testing has focused on the direct lithium extraction process for the extraction of lithium from the Leduc reservoir brine. Other technologies to be incorporated into the process flowsheet include reverse osmosis, ion exchange for polishing and removal of cations, precipitation, evaporation and crystallization processes to produce battery-grade lithium hydroxide monohydrate.

The proposed process for the purposes of the 2024 PFS was refined and modified over time, with the current preferred option representing a direct lithium extraction flowsheet followed by impurity removal and concentration of lithium chloride solution, precipitation of lithium as a solid lithium carbonate followed by dissolution of lithium back into solution, further impurity removal and lithium and reprecipitation as lithium hydroxide monohydrate. The 2024 PFS uses information from earlier programs in support of flowsheet design and simplification and is based on additional testwork completed in support of the study.

13.2 Direct Lithium Extraction

A significant amount of lithium extraction testing has been completed using brine sourced from the Leduc reservoir. The sample brine from the Leduc reservoir was mechanically sweetened by AMGAS using their CLEAR technology to remove hydrogen sulfide without introducing chemicals to the brine. The sweetened brine was subjected to testing of different sorbent technologies at bench scale and later at pilot level using selected preferred technologies.

Multiple manganate ion exchange and aluminate sorbent systems were evaluated at bench scale to demonstrate lithium recovery from the Leduc brine. Manganate ion exchange achieved lithium extraction recoveries from 89.1– 90.8% while the aluminate sorbents achieved recoveries from 90.0–95.0%.

A manganate ion exchange and an aluminate sorbent technology were each selected for pilot testing at E3's field pilot plant facility. The pilot project was to demonstrate the two technologies at larger scale and to further understand and demonstrate lithium recovery under continuously operating conditions. In addition to their extraction performance, these technologies were proven to significantly reject other brine species (Na, K, Ca, Mg, B) to facilitate impurity removal producing a high-quality lithium chloride eluate, and have been used in commercial applications. Elevated temperature and the presence of chloride led to the corrosion of ferrous surfaces.

Following piloting, an aluminate sorbent was identified as the preferred technology. Aluminate sorbent extracted approximately 92% of the lithium while rejecting over 99% of the magnesium, sodium, potassium, and calcium and over 92% of the boron. Subsequent testing on lithium extraction under process conditions (temperature and pressure) and in the presence of sour gas were conducted. Hydrogen sulfide was not observed to be adsorbed by the aluminate sorbent indicating no risk to either process or safety in operation and it did not prevent lithium from being loaded and stripped from the sorbent. However, sorbent performance over the long term have not been tested under sour conditions; this step is included in future test planning.

13.3 Lithium Chloride Solution Concentration and Polishing

The eluate solution following direct lithium extraction is comprised primarily of lithium and chloride, but contains impurities that must be removed to produce a battery grade lithium product. Laboratory-scale testing has confirmed that ion exchange can be used to soften the direct lithium extraction eluate reducing levels of barium, magnesium and strontium to levels <1.0 mg/L and calcium to below <2.0 mg/L. The results of the ion exchange indicated small quantities of lithium was adsorbed during the process and therefore the regenerate solution should be recycled to recover this lithium.

Reverse osmosis testing was completed at 1,000 pounds per square inch gauge (psig) on the ion exchange treated direct lithium extraction eluate to concentrate the lithium in solution. The reverse osmosis concentrate contained approximately 6,000 mg/L of lithium while the permeate contained only 8 mg/L indicating <1% of lithium losses in the reverse osmosis process while achieving approximately a 7.5 times increase in lithium concentration. As silicon was not present in the permeate, and only concentrated at approximately five times, indicating silicon precipitated during concentration, and potentially fouled the membrane.

Lithium was tested for further concentration by evaporating the reverse osmosis concentrate solution. Following initial acidification to remove carbonate alkalinity in the sample the sample was neutralized. Initially during evaporation sodium and lithium concentrations increased until reaching 18% lithium chloride (LiCl) and 9.1% sodium chloride (NaCl) at which point sodium chloride precipitation began. Calcium and silicon levels in the evaporator concentrate were lower than expected, indicating these species also partially precipitated.

13.4 Precipitation of Lithium Carbonate and Conversion to Lithium Hydroxide Monohydrate

Lithium chloride concentrate solution following evaporation was reacted with sodium carbonate to crystallize lithium carbonate ($LiCO_3$). Mother liquor was found to contain unprecipitated lithium and high concentration of sodium. As a result, a recycle stream of mother liquor was passed through an ion exchange to separate sodium from lithium with the lithium product stream able to return to the lithium chloride evaporation step for additional lithium precipitation.

Lithium carbonate was then redissolved and reacted with hydrated lime resulting in a 2.85% lithium hydroxide (LiOH) solution containing solid calcium carbonate. Following the removal of calcium carbonate solids, the remaining calcium in the lithium hydroxide solution was removed to <1.0 mg/L through ion exchange.

Evaporation testing of the lithium hydroxide solution showed that it could be concentrated to 13% LiOH with the concentrated brine then sent to a crude lithium hydroxide monohydrate crystallizer which was operated under vacuum. Analysis of the mother liquor showed a concentration factor of approximately 11.85 times. Carbonate did not concentrate, indicating that some lithium carbonate precipitate was formed. Washing of the crystal demonstrated the ability to reduce impurities on the crystal including aluminum, iron, potassium, silicon, sodium, zinc, carbonate, chloride, and sulfate.

The produced crystals were dewatered, washed and redissolved to produce a feed to the pure lithium hydroxide monohydrate crystallizer. The solution was covered in a nitrogen blanket to minimize carbon dioxide pick up. The feed brine contained 9.8% LiOH. The final crystallization produced crystals with a d50 of 800–850 µm, and washed crystals met the battery grade specification.

13.5 Recovery Estimates

Testing demonstrated consistent direct lithium extraction lithium recovery from brine with a reported average of 95.04% ±0.79% observed during testing. The low variability of the brine chemistry will enable consistent lithium recovery.

Downstream of the direct lithium extraction process, it is anticipated that 98% of the lithium recovered by the direct lithium extraction will be converted into solid lithium carbonate. The redissolution of lithium carbonate and precipitation of lithium hydroxide will recover 96.9% of the lithium for a final overall process recovery of 90.4% lithium into a lithium hydroxide monohydrate product.

13.6 Metallurgical Variability

Brine chemistry across the Bashaw district is relatively consistent with a narrow range of concentrations for lithium as well as for other species. E3 has collected samples across 65+ townships and has also collected a vertical brine profile in their most recent test wells and found the composition to have low variability. Descriptions of the brine chemistry as summarized in Section 7 and Section 11, show the consistency of the lithium grade measurements over time as well as across a large geographic area (refer to Figure 11-6).

13.7 Deleterious Elements

Silicon, boron, sodium, magnesium and calcium are the expected deleterious elements present in the Leduc brine. The concentrations of these elements are expected to be steady during plant operations. In compliance with battery grade lithium hydroxide monohydrate specifications, product is to contain <0.01 mg/L each of silicon, boron, sodium, magnesium and calcium.

13.8 QP Comments on Section 13

Additional testing on the direct lithium extraction process is anticipated to include long term repeated cycling of adsorption-rinse-desorption-rinse, including under sour brine conditions, to observe the sorbent longevity and susceptibility of thermal shock, any sorbent performance variability or loading limitation, and optimal column configuration.

Other testing will focus on de-risking unit operations. These other tests are anticipated to include ion exchange and evaporative processes that consider the unique brine chemistry, any potential for scaling or fouling of reverse osmosis membranes in the production of concentrated lithium chloride solution. Precipitation reactions, including lithium carbonate and lithium hydroxide, will be completed using previously-produced lithium chloride solution to confirm solubility equilibria.

14.0 MINERAL RESOURCE ESTIMATES

14.1 Introduction

The Brine Resource estimate for the Bashaw District is based on reservoir geometries and properties populated in a 3D geological and reservoir model developed using Petrel™ (Schlumberger Information Solutions, undated). Petrel™ is a commercial software platform that integrates geological and reservoir data.

The geological model included the following reservoir characteristics: area geometry, structure, thickness, porosity, permeability, and lithium concentrations (grade). The 3D geological model was used to geostatistically simulate and evaluate scenarios of connected porosity in the reservoir that were used as the basis for the resource estimate in the model domain. The model was validated in part based on existing and project developed maps and cross-sections of depositional environments, facies, diagenesis and oil and gas pools as described in Sections 6 and 7 of this Report. Additional validation by the QPs was completed by detailed review of the raw input data to the geological model, suitability of the geostatistical approaches applied, and output grids from the model.

14.2 Key Assumptions

The key assumptions for the Brine Resource estimate are listed in Table 14-1. The subsections that follow provide more detailed discussion.

Confined saline aquifers represent a distinct resource type for brine-hosted lithium deposits. The resource estimation methodology used is a new approach that the QPs believe honours the existing CIM Definition Standards and 2019 Best Practice Guidelines and incorporates methodology that has long been used in Canada through the NI 51-101 framework, the industry and national standard for resource estimation of petroleum liquids (or near liquids).

A CIM Best Practice Guideline exists for brine-hosted deposits, based on salar-based deposits which are hosted in unconfined aquifers subject to significantly different responses to pumping than confined aquifers.

Table 14-1: Estimation Assumptions and Rationale

Assumption	Rationale
Confined saline aquifers containing brine-hosted mineral resources can be estimated using effective porosity instead of specific yield	Reservoir will not be dewatered during production and confined conditions will be maintained through life of production.
The effect of reservoir compressibility (specific storage) is also not relevant to the resource estimate.	The project will be operated as a secondary recovery scheme supported by reinjection of the depleted brine.

Confined saline aquifers can leverage a methodology that has long been utilized in oil & gas development, where resource estimation of liquids (including high viscosity near liquids) is common practice and standardized in Canada through the NI 51-101 standard. Brine-hosted resources have more in common with petroleum resources than they do with hard-rock mining – but not all brine-hosted resources are created equal. Unconfined aquifers, which are connected to atmospheric pressure, are under a different pressure regime than confined aquifers, which are disconnected from atmospheric pressure due to the presence of low permeability confining layers (aquitards or seals) above the aquifer. There are often gases (generally dissolved but sometimes free in certain structures) present in confined aquifers that provide pressure support. Additionally, as required by regulation (e.g., Alberta Energy Regulator Directive 90) artificial pressure support is provided to the reservoir during production through reinjection of the depleted brine. In petroleum reservoir engineering, the ratio of injected volume (corrected to reservoir temperature and pressure conditions) to produced volume (corrected to reservoir conditions) is known as the "voidage replacement ratio", production that occurs without reinjection is referred to as "primary recovery", and with reinjection is called "secondary recovery". These pressure regimes and reservoir drive mechanisms are fundamentally different and therefore different resource estimation methodologies should be applied to each.

The original in place mass, specific to lithium resource estimation, has been termed "original lithium in place", representing the total mass present in the subsurface. Original lithium in place is the basis for the Brine Resource estimate.

Subsequently, the producible lithium mass has been termed "producible lithium in place", representing the total mass that can be brought to the plant inlet for processing. The final recoverable mass, termed "recoverable lithium in place" accounts for any losses during the processing stage and represents the total sales volume. These parameters are assessed as part of the Brine Reserve estimate in Section 15.

14.3 Parameters

Parameters required to estimate the confined aquifer Brine Resource are shown in Table 14-2.

14.4 Estimation Methods

The estimation methodology is presented in the following sub-sections for the key input parameters.

14.4.1 Pore Volume

Pore volume quantifies the space available within the rock formation that contains the Brine Resource. It was estimated from the reservoir model grid by summing the porosity values from all the cells above a minimum porosity threshold connected to an adjacent cell also meeting the threshold (and for defining the resource, containing a measured lithium sample within the connected pore volume).

Area Geometry: Area and Thickness

The reservoir model grid was spatially constrained by the extent of the reservoir and vertically by the thickness of the reservoir. Petroleum well data, described in Sections 6 and 7, were used to define the shape and extent of the Leduc reservoir. Defining the geometry of the Leduc reservoir was an iterative process which involved analysis of existing wells drilled for the exploration and production of hydrocarbons in the resource area. The geological mapping process using well data has been in practice in Alberta's petroleum industry for over 70 years to define geological formations. The Leduc Formation base and top were determined from well logs and seismic interpretation (see Section 7).

The boundary of the Leduc reef complex is challenging to define in the study area for three main reasons:

- The bias in well control preferentially in the carbonate reef complex with only a few minor penetrations that define the margin to basin transition;
- Extensive dolomitization tends to obliterate the primary textures, making it difficult to recognize typical facies, diagenetic fabrics and organisms characteristic of the margin (e.g. frame builders and fibrous marine cement);
- Limited seismic data.

Table 14-2: Estimation Parameters

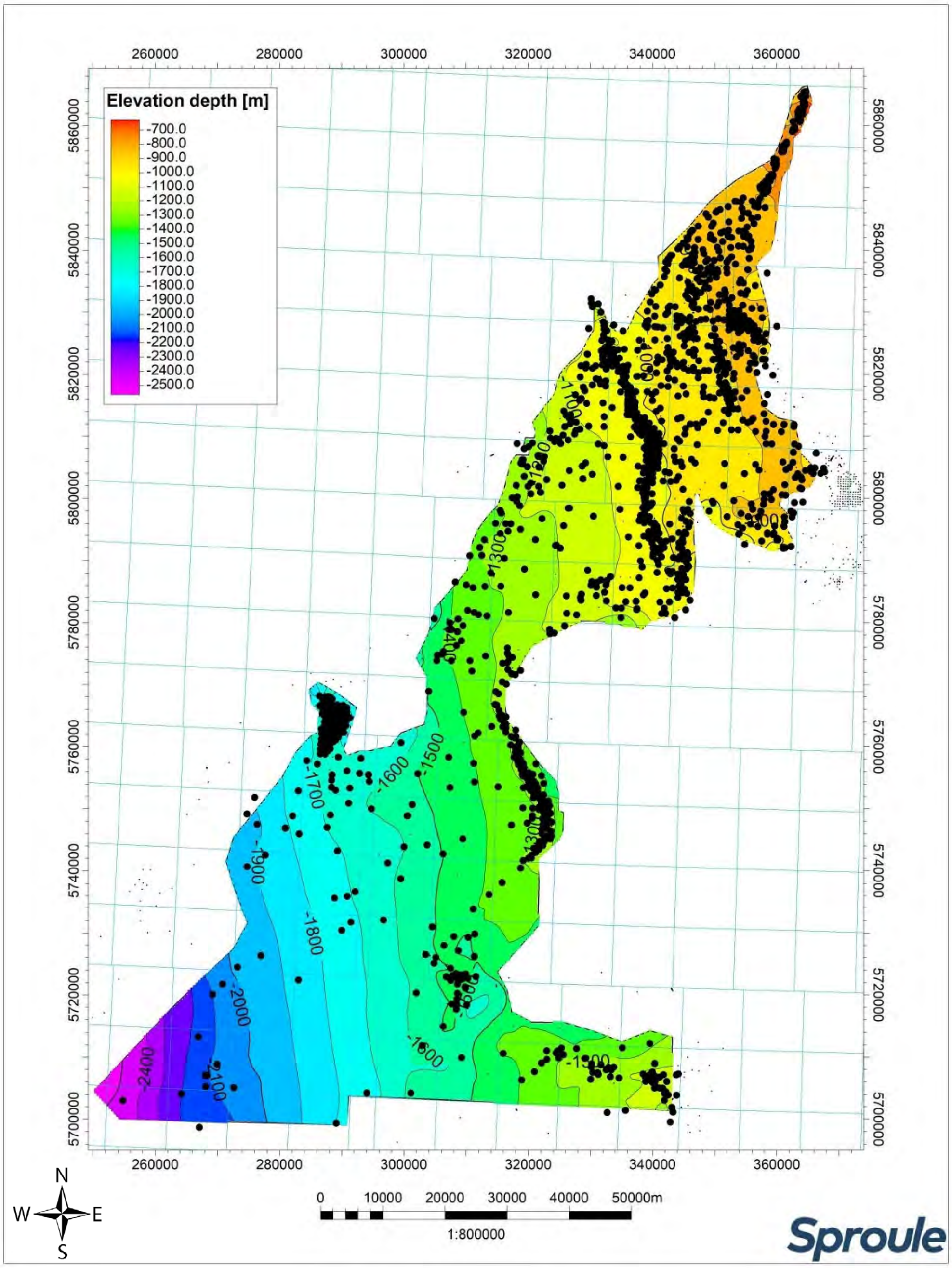
Parameter	Description
Original lithium in place	The total amount of lithium contained in the brine-hosted confined aquifer
Producible lithium in place	The total of amount of lithium that can be produced to surface from the brine-hosted confined aquifer
Pore volume	At the reservoir model scale, the volume of effective porosity represented by the model.
Connected pore volume	At the reservoir model scale, the volume of the cells that connect to other cells with a specified minimum porosity threshold.
Area	The areal extent of the confined aquifer
Thickness	The thickness of the confined aquifer
Total porosity (PhiT)	The total percentage of pore volume within a given rock volume
Effective porosity (PhiE)	The percentage of connected pore volume within a given rock volume
Water saturation	The percentage of pore volume filled by water/brine
Lithium concentration	The quantity of lithium dissolved in the brine in the confined aquifer by mass concentration. Also used interchangeably with the term “grade”.

As such, the “zero-edge” for the Leduc resource area is defined based on the change from high porosity Leduc carbonate reef complex from the surrounding low porosity carbonate muds and shales of the deep-water basin sediments occurring in the Ireton and Duvernay Formations. In the absence of well data and seismic interpretations, existing industry-standard Leduc edge interpretations were consulted (Potma et al., 2001; Hearn et al., 2011; Hearn and Rostron, 1997; Potma and Weissenberger, 2013; Mossop and Shetsen, 1994; and geoLOGIC Systems, 2022). The local and regional geological context was also taken into consideration when making interpretations.

Structure and Thickness

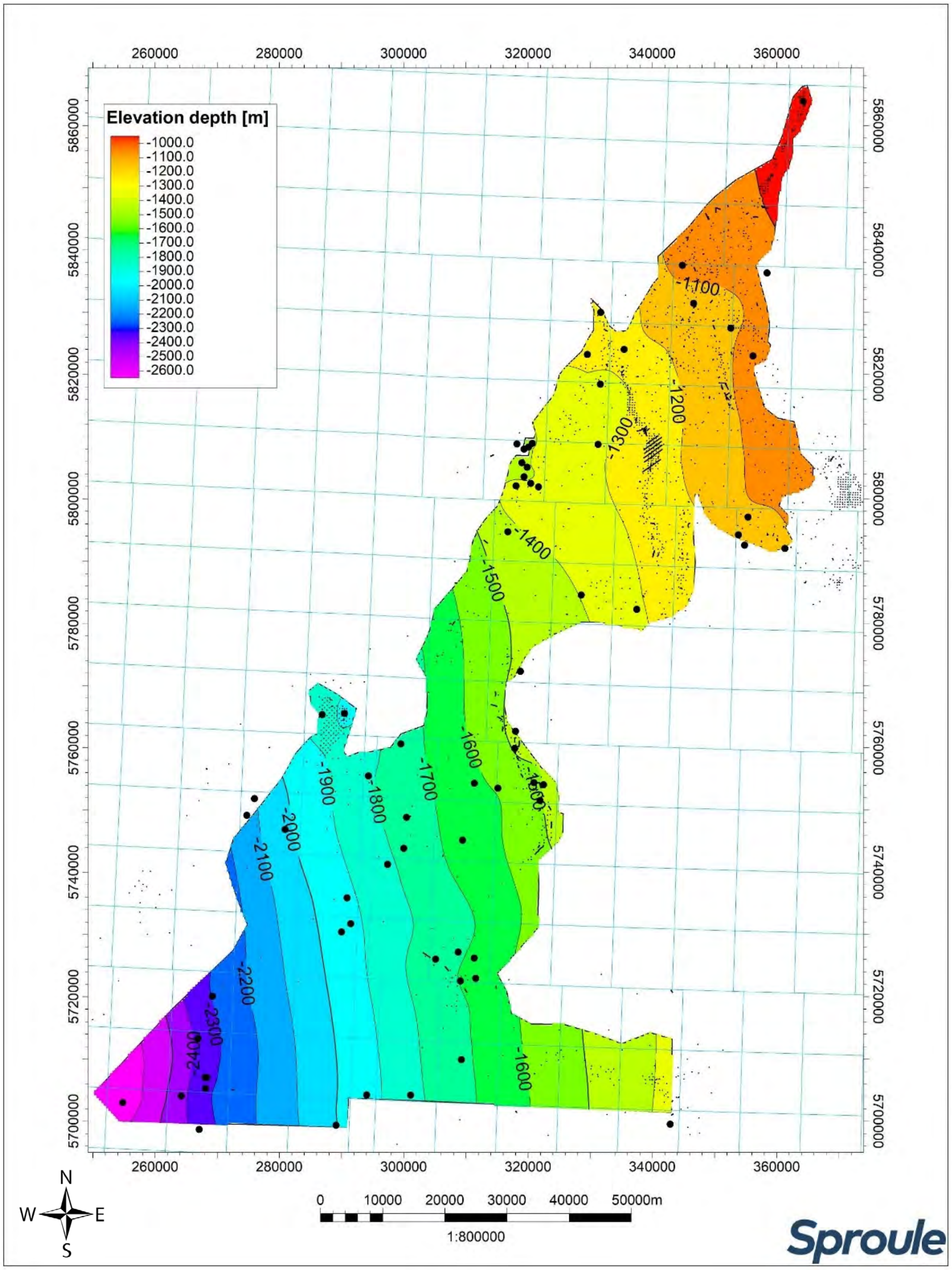
Geological interpretation was completed by E3 via the vetting and selection of geological formation tops over the Leduc, and Cooking Lake Formations. The Leduc Formation top was selected at the base of the Ireton Formation, which is predominantly shale. The Cooking Lake Formation was selected using a regional shale at the base of the Leduc Formation, and a combination of isopach thickness, and the gamma log where the regional shale was less distinguishable (discussed in Section 7). These formations were used for mapping structure and thickness for the Leduc and Cooking Lake Formations. The geological data set used to construct the maps was comprised of 2,397 wells with Leduc Formation structure tops (Figure 14-1), and 101 wells with Cooking Lake Formation structure tops (Figure 14-2).

Figure 14-1: Structure Top of the Leduc Formation



Note: Figure prepared by Sproule Associates Limited, 2024.

Figure 14-2: Structure Top of the Cooking Lake Formation



Note: Figure prepared by Sproule Associates Limited, 2024.

The model uses ordinary kriging for structure and thickness for the Leduc Formation across the Bashaw District. This methodology was considered by the QPs to be appropriate for spatially continuous data and is a deterministic method with a single result, with uncertainty qualitatively evaluated through interpretation of the variogram. The result was based on a spatial correlation between data points, capturing spatially variable mapped thickness of the formation at each grid column.

The geological tops and original maps were used as the framework inputs for the 3D geological model. New surfaces were imported in the Petrel model for the Leduc and Cooking Lake Formations. The model was constructed of individual cell blocks 400 x 400 x 0.5 m in size. This grid cell size was deemed appropriate to honour the potential heterogeneity in geological properties informed by the input data (i.e. well logs, core, and seismic data) and also be manageable computationally for completing additional analysis and future flow simulations. The model represents the entire range of thicknesses and accounts for the thinner edges and the thickest part of the reef complex (Figure 14-3).

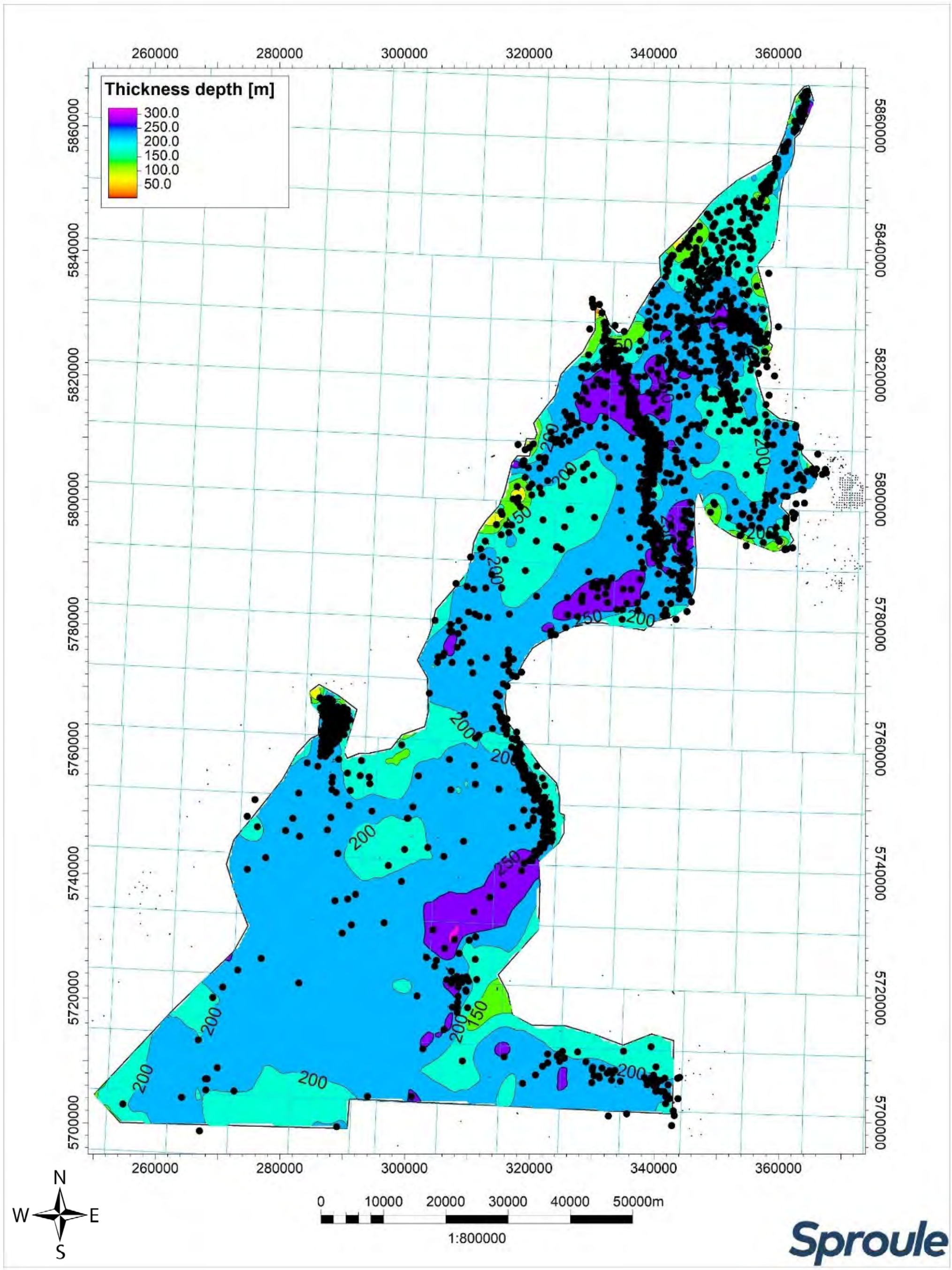
The confidence in the reservoir structure and thickness is high at the locations where it was picked at boreholes, as the interpretations are made from geophysical logs that are calibrated to the borehole depth, and have a relatively high vertical resolution of measurement. Given the range in depths of the formation picks and the number of control points available in the Bashaw District area, the uncertainty in the structure between the measured points is relatively low and would have a lower impact on the resource volume as compared to other input parameters like porosity and grade.

Porosity

Multiple techniques were used to evaluate the porosity of the reservoir. Porosity estimates of lithofacies units in the Bashaw District were informed by facies-based porosity estimates published by Atchley et al. (2006) and further constrained by core plug measurements and wireline data. Wireline photoelectric curve data was used to determine lithology, specifically in this case between limestone and dolomite (Kennedy, 2002).

This distinction is important to the characterization of porosity as dolomite typically has a higher porosity than limestone. The majority of the porosity measurements were determined using petroleum industry standard neutron/density open hole logs, which measure hydrogen concentration and electron density, respectively (Asquith and Krygowski, 2006). There are multiple methods for measuring porosity from core samples in the oil and gas industry, and some evaluate effective porosity while some evaluate total porosity (American Petroleum Institute, 1998). The most common routine core porosity analysis used in Western Canada are completed on dried samples and use injection of helium gas to estimate the connected porosity using Boyle’s Law. This would be an estimate of effective porosity.

Figure 14-3: Gross Isopach Map of the Leduc Formation



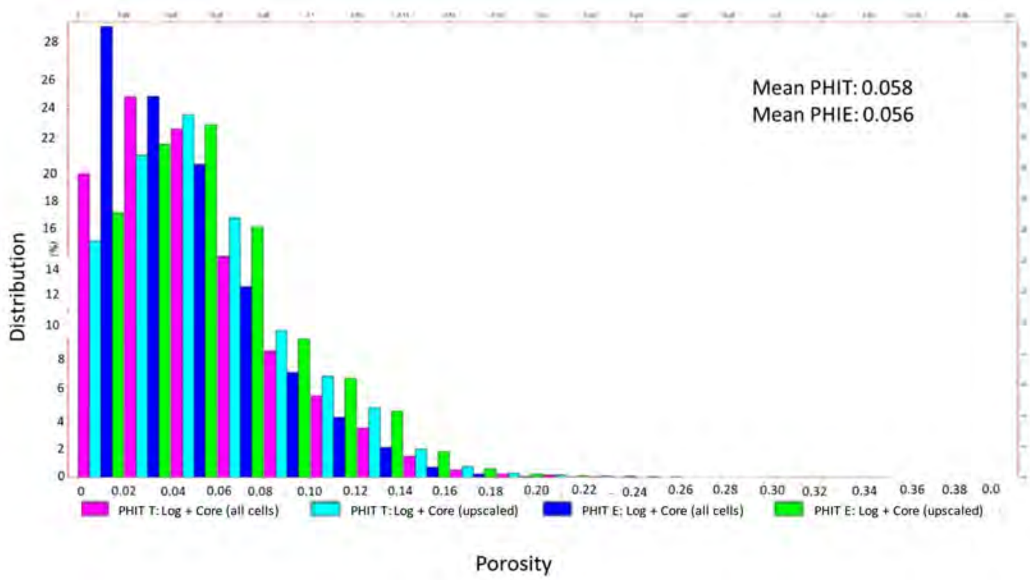
Note: Figure prepared by Sproule Associates Limited, 2024.

Modelling of porosity in the 3D in Petrel used sequential gaussian simulation to populate 50 equiprobable three-dimensional realizations for porosity. The model allowed for quantification of 3D spatially connected volumes, described in Petrel as “geobodies”, above a given porosity cut-off and connected to a lithium grade sample location. Connected cells that were separated from other areas of connected cells are modelled as unique geobodies and identified as such in the model outputs. Effective porosity was the input parameter used in these simulations and a sensitivity case based on total porosity was completed for validation purposes. The method for establishing the input dataset for effective porosity for the simulation was as follows:

- Compile all available porosity measurements from geophysical logs and core analyses in the model domain;
- Perform petrophysical analysis and corrections on available geophysical logs to establish a PhiT log where possible (57 wells);
- Correct the PhiT measurements from geophysical logs to PhiE. In this study, effective porosity for geophysical measurements was estimated by using a shale volume (Vshale) correction applied from the gamma ray log. This assumes that clay content would be the major influence total vs. effective porosity, which has not been confirmed for the Leduc reservoir and introduced some uncertainty that log derived effective porosity represents the true formation effective porosity. To reduce the uncertainty in this correction, the corrected PhiE was validated against the core measured porosity where available. The results of this validation showed that the estimated PhiE was a reasonable representation of the core porosity;
- The data were declustered and a corrected PhiE histogram was developed. Data declustering is a standard geostatistical tool used to remove bias from a given data set (Deutsch, 2021). During the declustering, each data point was assigned with a specific weight reflecting the relative percentage of reservoir area or volume which this data represents (Pyrcz and Deutsch, 2007). The data points remained unchanged, but the contribution to the modelled histogram and mean changed and depended on the assigned weight. his methodology reduced the weighting in the higher density areas of the dataset, which are generally coincident with the reef margin lithofacies;
- The declustered porosity data was then upscaled to the reservoir model grid prior to running sequential gaussian simulation. For model grid cells that contained multiple measurements, an average of all the values in that grid cell were calculated.

All of the individual measurements of porosity from the PhiE curves and core analysis were used as input data for the geostatistical analysis. A histogram illustrating the porosity distribution of the raw input data for both PhiE and PhiT relative to the final upscaled porosity input data is illustrated in Figure 14-4.

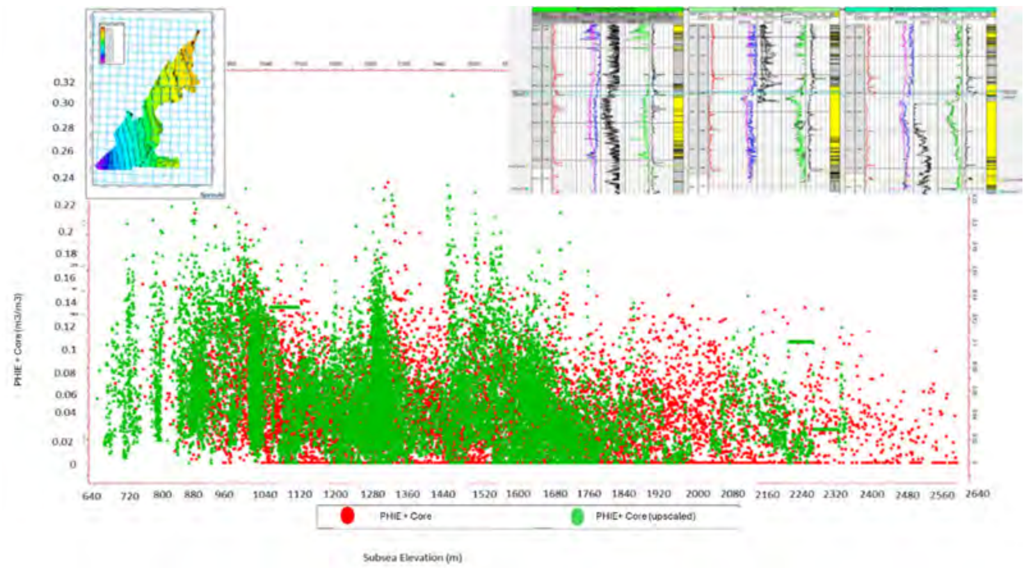
Figure 14-4: Porosity Histogram from Core and Log Data



Note: Figure prepared by E3, 2023. PhiT = total porosity; PhiE = effective porosity.

With the sequential gaussian simulation method, the input data points are honoured as well as the mean and standard deviation of measured effective porosity dataset (after upscaling to the model grid scale size). Following a randomised path through the grid, kriging is used to estimate/simulate the mean porosity and standard deviation based on the local data and variogram and assign values to each node. Within each simulation using sequential gaussian simulation the expected heterogeneity represented by the measured data is better represented than when using deterministic kriging. Additionally, multiple simulations were performed to evaluate the parameter uncertainty in porosity and the connected porosity volume (which was deemed to be a key parameter to constrain for the resource estimate). Fifty unique three-dimensional realizations of porosity were completed to quantitatively evaluate the uncertainty in these parameters, with each one of these realizations honouring the data and the variogram. In addition to honouring the distribution of the input data, an additional function was included in the reservoir modeling of porosity, to apply a decrease in porosity versus depth in the reservoir as this was observed in the input data (Figure 14-5). This was based on a linear regression model established from the PhiE data versus elevation in the reservoir.

Figure 14-5: Declustered Porosity Data Showing Porosity-Depth Relationship In The Geological Model



Note: Figure prepared by E3, 2023. PhiT = total porosity; PhiE = effective porosity.

For this Report, the resource estimate is based on effective porosity, as total porosity includes disconnected pores which are not accessible for fluid flow. To evaluate the difference between total and effective porosity, and to help provide additional confidence whether total or effective porosity was being provided by a given dataset, a crushed rock analysis was performed on three core plugs collected from E3's test well program.

This analysis first measured the porosity using standard helium displacement into the pore space. As the helium can only move into connected pore space, it represents effective porosity. The density of the sample is measured, with the volume and density of the helium known. The analysis then crushes the core sample, and again measures the density. The difference between the density of the intact sample and the crushed sample represents the total porosity of the sample. Any density difference between the gas injection results and the crushed sample results quantifies the isolated pore space.

The analysis determined that the total and effective core porosities were approximately equivalent above 6% porosity, meaning that there was no significant amount of isolated porosity for samples with a total porosity above 6%. This information, in addition to the QP's understanding that most of the historical core analysis are expected to have been measured using gas injection (McPhee et al., 2015), provides sufficient confidence that the entire core porosity dataset can be considered as effective porosity, and was implemented as such in the geological model.

As the difference between total and effective porosity has been measured to be minimal at 6% and above, the uncertainty around whether a given input data set is representing total or effective porosity for porosities above this threshold becomes less important for resource estimation. Quantification of the difference between total and effective porosity above 6% supports increased confidence that the log porosity measurements, in addition to the core samples, at this value and higher would be representative of the effective porosity of the reservoir.

Two separate porosity cut-offs were applied to estimate the pore volumes associated with the Measured and Indicated Brine Resource estimates, to represent a differing level of confidence in what porosity values can be associated with permeability values that would readily produce brine:

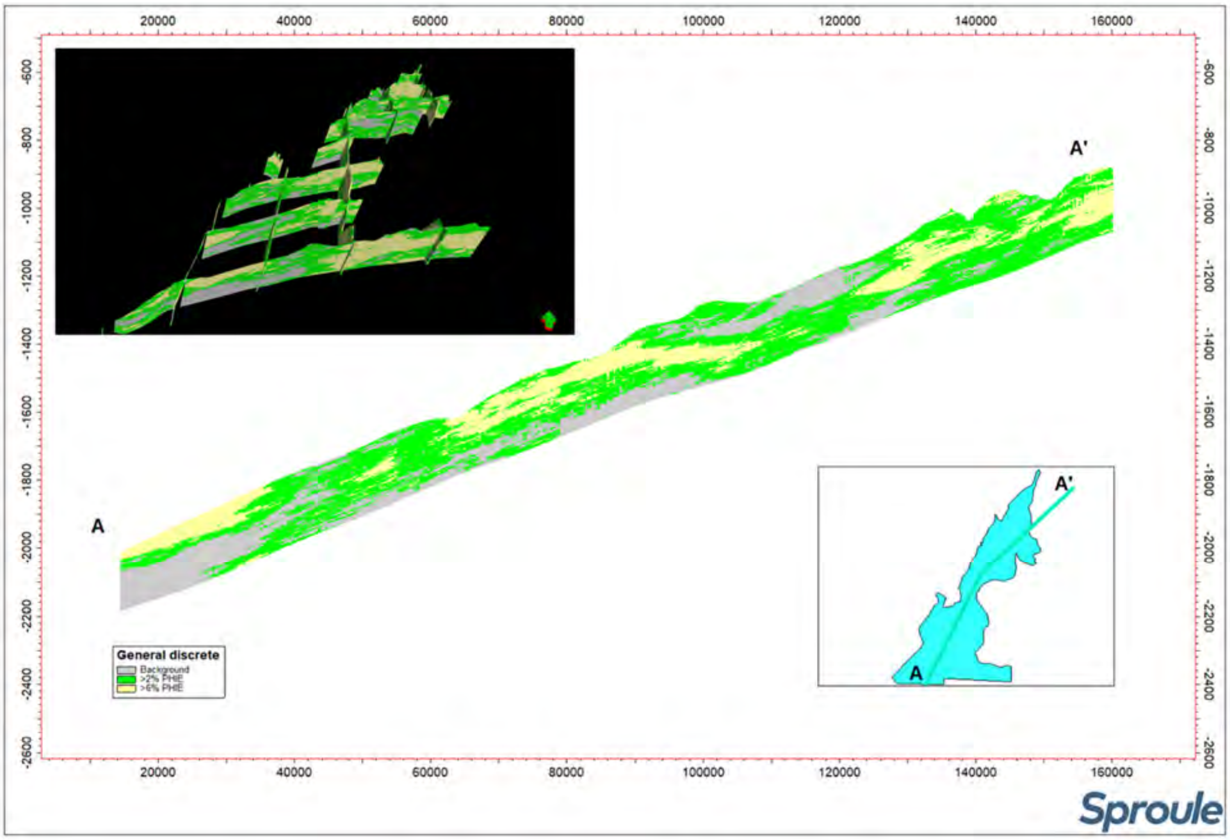
- A 6% porosity cut-off was determined for the Measured Brine Resource estimate because there was higher confidence that higher porosity intervals will have higher permeability and will preferentially flow fluid first when a well is put into production;
- A 2% porosity cut-off was determined for the Indicated Brine Resource estimate because there was sufficient confidence that porosity above this value would flow to a well for production over the economic lifetime of a brine production well (i.e. decades).

Further discussion of the justification of the porosity cut-offs are provided in the proceeding sections. A fence diagram through the geomodel, from a single realization showing the 3D distribution of the porosity cut-offs, is provided in Figure 14-6.

14.4.2 Water Saturation

Direct measurement of dissolved gas saturation in the brine from fluid samples collected at reservoir conditions increased confidence in the input value of 99% water saturation used in the resource estimate, with as the brine saturation was >99%, and the entrained gas saturation was <1%. The samples were collected at reservoir conditions (90°C and ~20,000kPa) via a controlled displacement tool.

Figure 14-6: Fence Diagram Illustrating Distribution Of Porosity Cut-Offs Across The Bashaw District



Note: Figure prepared by Sproule Associates Limited, 2023.

The samples were maintained at reservoir conditions and transported to Core Laboratories Advanced Technology Centre for analyses.

14.4.3 Lithium Concentration (Grade)

The individual measured lithium concentrations in the Bashaw District have a P90–P10 range of 69.8–82.0 mg/L with a P50 of 74.6 mg/L. When the samples were spatially aggregated (samples from the same location at different times were averaged), the P90–P10 range was 70.1–82.2 mg/L with a P50 of 75.5 mg/L. E3's vertical sampling was included in this data set, which addressed a key uncertainty noted in previous Brine Resource estimates. The lack of variation in measured vertical lithium grade supported the overall continuity of lithium across the Bashaw District as was previously indicated by the lateral sample distribution. This was consistent with the emplacement model discussed in Section 8 and validated the assumption that the grade was homogeneous in the vertical and lateral directions.

In addition to the vertical profiling of the Leduc Formation, E3 reviewed the entire lithium dataset and refined the elevation of the intervals that were previously sampled. E3 evaluated two approaches to investigate the spatial continuity and statistical distribution of the revised grade dataset: variography; and descriptive statistics.

Vertical and horizontal variograms were examined for the grade dataset. Qualitatively, these variograms indicated that variance in the input dataset was low, and near-distance variance was greater than further-distance in the dataset. This was interpreted by the QPs to represent variance in the sample laboratory analysis as opposed to actual grade variance in the reservoir. Ultimately, it was determined that there was an insufficient variance and inappropriate spatial distribution of sampling data to apply variography (and therefore kriging) to evaluate the grade distribution in the reservoir.

While geostatistical approaches such as kriging and variography evaluate spatial continuity in a dataset, for descriptive statistics it must be assumed that the samples are representative of the population. E3 evaluated two descriptive statistical measurements to further evaluate the confidence in the assumption that the lithium grade distribution is homogeneous:

- The coefficient of variation for the sample set was calculated for both the raw samples dataset (n = 102) and the sample set with temporally averaged samples (n=55) and found to be very low (0.08 and 0.07) in both cases. The fact that temporal averaging reduced the coefficient of variation supports the finding from the variography work that laboratory measurement error may be resulting in much of the current variance observed in the samples, as these samples were collected from the same well completion interval;
- A confidence interval following Student's t-distribution was constructed, based on the assumption that samples were drawn from the same population. For the temporally averaged dataset, the mean lithium grade was estimated at 75.5 ± 1.36 mg/L throughout the Bashaw District.

Based on the statistical evaluation and the completion of the vertical grade profiling, the QP determined that the sample dataset represented a large regional area across the Bashaw District and within this dataset, lithium grade variance was small and there were no mappable spatial trends in the grade. This result is expected for a regionally continuous, hydraulically connected aquifer, where the emplaced lithium has been regionally distributed through advective and dispersive groundwater flow over a long period of geological time. Based on this analysis, the QPs believe it is reasonable to apply the P50 lithium concentration of 75.5 mg/L as the lithium grade across the Bashaw District to estimate the volumes for Measured and Indicated Brine Resource volumes.

14.4.4 Permeability

Permeability was evaluated to support development of porosity cutoffs and to determine if the resource has a reasonable prospect of eventual economic extraction. Linear regression analysis was done on the core data to evaluate the relationship between porosity and permeability.

Multiple techniques were used to evaluate the reservoir permeability (Table 14-3).

Core plugs are mainly confined to wells cored within the hydrocarbon producing pools, meaning that they are confined to the upper part of the Leduc reservoir and represent predominantly the reef margin, reef flat to open lagoon facies. Core from E3 Lithium's 2022 drill program was gathered specifically to evaluate the interior restricted lagoon lithofacies and the lower Leduc, which are underrepresented in the publicly available dataset.

Drill stem test analysis was completed by Melange Geoscience Inc. on a subset of what was considered to be high-quality drill stem test data. Pressure build-up curves were analyzed on five drill stem tests in the Leduc Formation in the Bashaw District. Drill stem tests were performed over reservoir classified as Facies-1, reef flat to reef margin and Facies-2, and reef interior to open lagoon. This analysis was performed in 2019 and remains valid at the Report effective date.

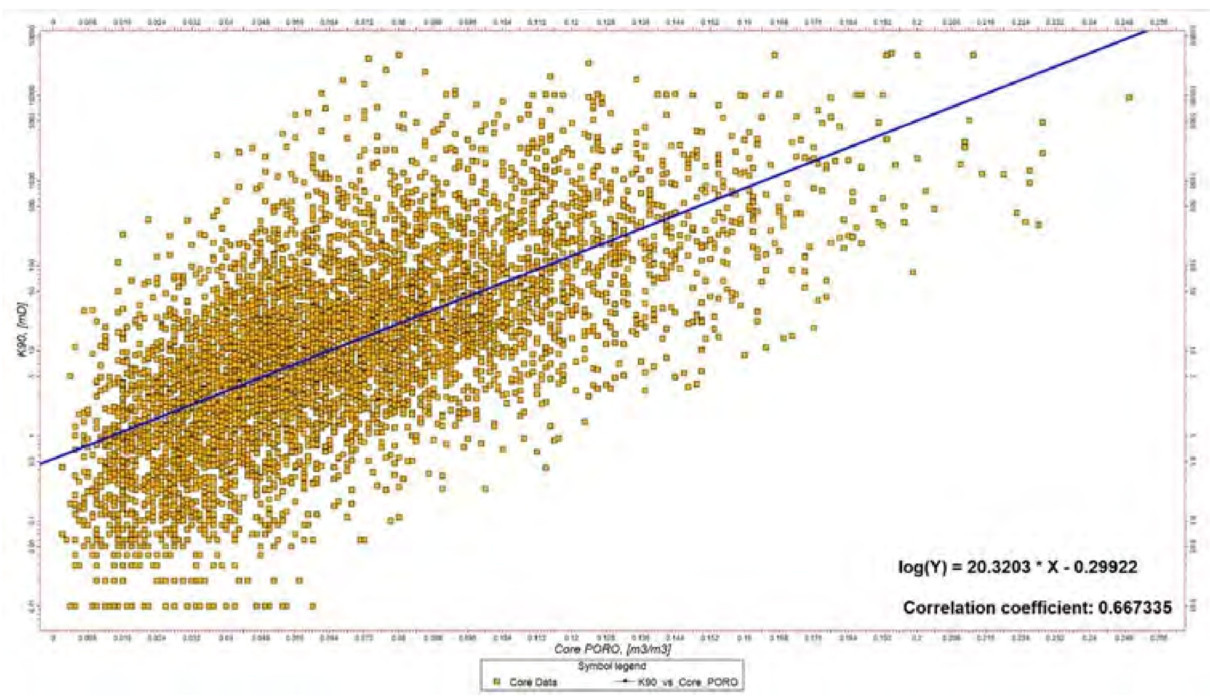
The core plug permeabilities reflect high quality estimates of permeability on a sub-wellbore-scale (cm-scale) and the drill stem test-derived permeabilities reflect high quality estimates of permeability on a near wellbore-scale (m-scale to 10s of m-scale). Both historical data sets tend to be biased towards the "best reservoir" as they were completed to analyze hydrocarbon potential within a reservoir, and as such typically provide the highest results for permeability measurements. The QPs decided that, based on the large range of permeabilities within the core plugs, a more conservative representation of reservoir permeability exclusive of the fracture permeability (because core plugs typically represent unfractured rock samples) was the core K90 measurement of permeability. The K90 permeability was measured at 90º to the maximum permeability direction within the core plug. This was interpreted to represent reservoir permeability that was dominated by the rock matrix driven by intercrystalline porosity associated with replacement sucrosic dolomite texture (euhedral dolomite crystal shapes). The regression model is illustrated in Figure 14-7.

Because a large volume of core analysis results were available that corresponded to measurements of effective porosity, a regression analysis was completed to evaluate a relationship between these parameters.

Table 14-3: Permeability Data Sources and Range of Values

Data Source	Estimated Permeability Range [mD]
Published permeability estimates of the Leduc and Cooking Lake Formation reservoirs	Leduc Formation: 5–6,000 Cooking Lake Formation: 0.13–3
Core plug test analysis	0–31,392
Drill stem test analysis	1,721–4,646
Petrophysical analysis (linear regression porosity-permeability comparisons)	0–27,127
E3's 2022 flow test (production/injection)	20–100

Figure 14-7: Cross-Plot of the Porosity-Permeability Relationship



Note: Figure prepared by Sproule Associates Limited, 2023.

Long-term production tests or actual production data provide data to estimate an average formation permeability that covers hundreds of metres or kilometres of scale in the reservoir. To provide this information, E3 completed a 10-day flow and build-up test in the reservoir at E3's 102/01-16-033-27W4 well. This location was also strategically selected to provide permeability and porosity data for the lower energy lagoon facies. Data recorders measured the reservoir pressure response from the production and injection, which was analyzed by an independent third-party expert (IHS Markit, part of S&P Global) to determine the reservoir permeability within the interior lagoon facies.

The porosity/permeability relationship was interpreted to indicate a high confidence that 6% porosity could be associated with an extractable resource volume and 2% a moderate confidence.

14.5 Grade and Mineral Equivalent

Lithium concentration is expressed as a mass concentration (mg/L), as measured in the laboratory analyses. The concentration converts to mineral tonnage of elemental lithium using the brine volume multiplied by mass concentration. The tonnage of elemental lithium can be converted into various mineral equivalent forms using scaling factors based on the molar ratio, which is the proportion of lithium in the mineral forms relative to their total molecular weights. For example, elemental lithium tonnage is converted to the industry standard value of lithium carbonate equivalent using a conversion factor of 5.323. This factor is derived using a molar ratio of 0.188, which represents the proportion of lithium in lithium carbonate by molecular weight. As the Project will be producing lithium hydroxide monohydrate, the tonnage of elemental lithium is also converted to lithium hydroxide monohydrate, using a conversion factor of 6.046, which is based on a molar ratio of 0.165 lithium content in this compound.

14.6 Brine-Hosted Mineral Resource Estimate

The Bashaw District resource area was treated as a single continuous reservoir based on continuity in porosity (>2% effective porosity connected pore volume), consistency in lithium grade, and observed pressure dynamics. A cut-off grade was not used in this assessment because the grade within the reservoir was determined to be homogeneous and therefore the factor controlling the resource volume will be the effective porosity distribution and connectivity in the reservoir.

Development of the methodology to estimate the resource and determination of the final resource estimate was completed by the QPs in consultation with the project technical team. It was an iterative process directed by the QPs. The general approach adopted by the QPs for methodology development and validation was as follows:

- Discussion between QPs and technical team of the conceptual model for the reservoir, continuity of porosity and grade, and possible methodologies to evaluate the confidence in the key input parameters (porosity and grade);
- QP review of all input data and variograms for key input parameters;
- Generation of model realizations of porosity using sequential gaussian simulation by the technical team;
- QP review of the model output grids. Specific aspects of the review included:
  - Ability of the model to fit input data through spot checks and confirming that the range and mean of the model represented porosity was consistent with the inputs;
  - Consistency of the model outputs with the geological conceptualization of the reservoir including higher porosity margin areas and a general decrease of porosity with depth;
  - Evaluating the range of outcomes of connected porosity volume and associated sensitivity on the resource estimate;
  - Confirming accounted pore volume would be within either the freehold or crown land extents of E3's mineral claims;
- Estimation of the resource volumes by the technical team based on the model outputs for connected porosity volumes and the selected grade value;
- Validation of resource estimate calculations by the QP's through independent calculation.

The geostatistical simulation of 50 equally plausible 3D effective porosity distributions for the resource quantified the uncertainty in the estimated brine connected pore volume (and by extension resource volume) accounting for the uncertainty in the measured data. Specifically, based on the current data locations, density and range in the effective porosity values, the difference in overall P10 and P90 brine connected pore volume using a 2% porosity cut-off between all 50 realizations is 12% (Table 14-4). Based on the low range in variance of the connected pore volume and validation of the output results described above, the QPs selected the P50 volume calculated from the 50 realizations that evaluated the connected effective porosity as the basis for the estimate.

Table 14-4: Bashaw District Brine Volume above 2% Effective Porosity Cut-Off

<table>
<tr><th>Connected Pore Volume (m^3)</th><th>Bashaw Original Oil In Place (m^3)</th><th>Brine Volume (m^3)</th></tr>
<tr><td>P50: 55,853,000,000
P90: 53,600,000,000
P10: 60,770,000,000</td><td>54,299,410</td><td>P50: 40,355,000,000
P90: 38,125,000,000
P10: 45,223,000,000</td></tr>
<tr><th>Li-Rich Brine Saturation (%)</th><th>Bashaw Original Gas In Place (m^3)</th><th>Brine Volume (km^3)</th></tr>
<tr><td>99</td><td rowspan="3">15,036,100,000</td><td rowspan="3">P50: 40
P90: 38
P10: 45</td></tr>
<tr><th>Li Concentration (mg/L)</th></tr>
<tr><td>75.5</td></tr>
</table>

Note: Significant digits were used for table formatting purposes, but no rounding occurred until the final step of the resource estimate (mass calculation of original lithium in place in tonnes of lithium).

The Brine Resource estimate excludes hydrocarbons and any pore volume associated with them. The hydrocarbon pore volumes from the Leduc Formation oil and gas fields in the project area were obtained from public data and the sum of the original oil in place and original gas in place from Leduc pools in the Bashaw District were removed from the total connected pore volume.

As oil in place and original gas in place volumes are reported at surface conditions and both fluids are significantly more compressible than water, the formation volume factors (average of values reported by the Alberta Energy Regulator for each pool) were applied to calculate the pore volume at reservoir conditions.

The following methodology was used for the total brine volume estimate:

- Step 1: export the total connected pore volume from 50 realizations of the geological, and calculate the P50 value from 50 realizations for areas greater than 2% effective porosity cut-off;
- Step 2: subtract the oil in place and original gas in place from the P50 total connected pore volume to determine non-hydrocarbon saturated pore volume;
- Step 3: multiply the non-hydrocarbon saturated pore volume by the brine saturation of 99% to determine brine volume.

The brine volume in the Bashaw District was calculated to be about 40 km^3 of brine with a reasonable prospect of economic extraction (Table 14-4). The numbers for the Clearwater Project area are reported in Table 14-5.

Table 14-5: Clearwater Project Area Brine Volume Above a 2% Porosity Cutoff as a Subset of the Bashaw District Brine Volume

<table>
<tr><th>Connected Pore Volume (m^3)</th><th>Bashaw Original Oil In Place (m^3)</th><th>Brine Volume (m^3)</th></tr>
<tr><td>P50: 7,548,000,000
P90: 6,737,000,000
P10: 8,918,000,000</td><td>14,300,660</td><td>P50: 7,454,000,000
P90: 6,651,000,000
P10: 8,810,000,000</td></tr>
<tr><th>Li-Rich Brine Saturation (%)</th><th>Bashaw Original Gas In Place (m^3)</th><th>Brine Volume (km^3)</th></tr>
<tr><td>99%</td><td rowspan="3">4,570,237</td><td rowspan="3">P50: 7.5
P90: 6.7
P10: 8.8</td></tr>
<tr><th>Li Concentration (mg/L)</th></tr>
<tr><td>75.5</td></tr>
</table>

For the current Clearwater Project area, oil in place and original gas in place numbers were compiled from the Innisfail, Lone Pine Creek and Wimborne hydrocarbon pools (Government of Alberta Public Data, via Accumap, 2024). While these pools are mostly located outside of the current project area boundary, it was considered conservative for the purposes of the resource estimate to incorporate these pool volumes in the estimate as described in the methodology.

14.6.1 Measured Brine Resource Criteria

Based on the porosity-permeability relationship presented in Figure 14-7, permeability values at reservoir core porosities (which represent effective porosity) of 6% or greater range from 0.1–to 30,000 mD with a regression fit of approximately 10 mD. For reservoir permeability >10 mD the QPs have:

- High confidence that this rock volume has permeability that will support pumping rates that have reasonable prospects for eventual economic extraction;
- High confidence that this rock volume has been adequately sampled and assessed via the information compiled to date by E3 to provide sufficient confidence in the continuity of these zones to support a Brine Reserve estimate.

The QPs note that there are measurements <10 mD at this porosity but a significant number of measurements exceed this threshold and therefore the QPs have moderate confidence that the rock volume represented in the 3D geomodel with an effective porosity of at least 6% has permeability of at least 10 mD.

Through the core analysis completed by E3, physical measurements for porosity values of 6% or greater, demonstrate that the difference between total and effective porosity is negligible. Therefore, the QPs have high confidence that for the input data used to parametrize the 3D porosity model, whether derived from geophysical log measurements or physical core measurements, are representing the effective porosity of the reservoir.

For these reasons, the 6% or greater connected effective porosity geobodies containing at least one measurement of lithium grade were defined as Measured Brine Resources.

14.6.2 Indicated Brine Resource Criteria

Based on the porosity permeability relationship presented in Figure 14-7, permeability values at reservoir core porosities (which represent effective porosity) of 2% or greater range from 0.04–1,000 mD with a regression fit of approximately 1 mD. For reservoir permeability >1 mD the QPs have:

- Moderate confidence that this rock volume has permeability that will support pumping rates that have reasonable prospects for eventual economic extraction;
- Moderate confidence that this rock volume has been adequately sampled and assessed via the information compiled to date by E3.

The QPs note that there are measurements <1 mD at this porosity but a large number exceed this threshold and therefore the QPs have moderate confidence that the rock volume represented in the 3D geomodel with effective porosity of at least 2% has a permeability of at least 1 mD.

Through the geomodelling analysis, E3 demonstrated that a single connected effective porosity geobody of 2% or greater exists that is continuous over about 99.5% of the Bashaw District area in all 50 stochastic realizations of effective porosity. These realizations support the interpretation that the 2% and greater effective porosity geobody may represent the regionally connected reservoir system that is evidenced by the regional pressure continuity and homogeneous lithium grade distribution in the reservoir.

For these reasons, the 2% and greater connected effective porosity geobodies containing at least one measurement of lithium grade were classified as Indicated Brine Resources.

14.6.3 Measured and Indicated Volumes

The steps to estimate the Measured Brine Resource volume were:

- Step 1: for each of 50 realizations, generate a geobody showing all connected porosity above 6% porosity that intersects a measured lithium grade data point;

- Step 2: extract the P50 pore volume (net pore volume-Measured) from the 50 realizations;
- Step 3: calculate the net brine volume-Measured (net pore volume-Measured from step 2 minus the hydrocarbon pore volume) x brine saturation of 99%. For the resource estimate, it was considered to be conservative to exclude 100% of the free hydrocarbon saturated pore volume (original oil in place + original gas in place) from the Measured Brine Resource portion of the reservoir;
- Step 4: calculate the original lithium in place (tonnes) (net lithium volume = net brine volume (m^3) x 1,000 (L/m^3)) x P50 Li concentration (mg/L])/one billion (mg/t));
- Step 5: calculate the original lithium in place lithium carbonate equivalent (lithium tonnes from Step 4 x 5.323)

The steps to estimate the Indicated Brine Resource volume were:

- Step 1: for each of 50 realizations, generate a geobody showing all connected porosity above 2% porosity that intersects a measured lithium data sampling point;
- Step 2: extract the P50 pore volume from the 50 realizations and subtract the net pore volume-Measured to calculate the net pore volume-Indicated;
- Step 3: calculate the net brine volume-Indicated (net pore volume-Indicated from step 2 minus the hydrocarbon pore volume) x brine saturation of 99%;
- Step 4: calculate the original lithium in place (tonnes) (net lithium volume = net brine volume (m^3) x 1,000 (L/m^3)) x P50 Li concentration (mg/L])/one billion (mg/t));
- Step 5: calculate the original lithium in place lithium carbonate equivalent (lithium tonnes from Step 4 x 5.323).

For reference, the net pore volume–Measured value that was used as inputs to this workflow for the Bashaw District was 31,898,000,000 m^3 and for Clearwater Project was 4,571,000,000 m^3. The resulting net brine volume–Measured values were 16,640,000,000 m^3 and 4,507,000,000 m^3 for the Bashaw District and Clearwater Project area, respectively.

The net brine volume–Indicated was 23,715,000,000 m^3 and 2,947,000,000 m^3 for the Bashaw District and Clearwater Project, respectively.

14.7 Brine Resource Statement

The estimates are reported inclusive of those Brine Resources converted to Brine Reserves using the 2014 CIM Definition Standards. Brine Resources that are not Brine Reserves do not have demonstrated economic viability.

The Qualified Persons for the Brine Resource estimates are Mr. Daron Abbey, P. Geo and Alex Haluszka, P. Geo, both of Matrix Solutions Inc.

The estimates have an effective date of June 20, 2024.

A summary of the Measured, Indicated and Measured + Indicated Brine Resource volumes for the Bashaw District is provided in Table 14-6 and for the Clearwater Project area in Table 14-7. Table 14-7 is not additive to Table 14-6.

For calculated parameters (lithium carbonate equivalent and lithium hydroxide monohydrate), rounding occurred after conversion. The reported volumes are for the entirety of the Bashaw District and Clearwater Project areas as defined in Section 4 of this Report, which comprise a contiguous perimeter around E3's brine hosted mineral permits within these areas inclusive of both freehold and Crown land parcels.

A visual representation of the Measured and Indicated volumes are shown in Figure 14-8, based on a single realization where the volumes are closest to the P50 volumes. As the P50 volumes were calculated from the exports across all 50 realizations, no single realization is an exact match to the reported resource volume estimate. The visual representation projects the vertical variation to a plan view, based on the ratio of measured and indicated volumes occurring in a given column of model grid cells. Where the ratio is above 0.5, the representation shows green for Measured; below 0.5, the representation shows yellow for Indicated.

Table 14-6: Bashaw District Total, Measured, and Indicated Resource Estimates

Confidence Category	Original Lithium In Place (t Li)	Original Lithium In Place (t lithium carbonate equivalent)	Original Lithium In Place (t lithium hydroxide monohydrate)*
Clearwater Measured Brine Resource (excluding hydrocarbon pore volumes)	1,256,300	6,687,200	7,595,500
Clearwater Indicated Brine Resource (excluding hydrocarbon pore volumes)	1,790,500	9,530,900	10,825,500
Clearwater Measured and Indicated Brine Resources OLIP (excluding hydrocarbon pore volumes)	3,046,800	16,218,100	18,421,000

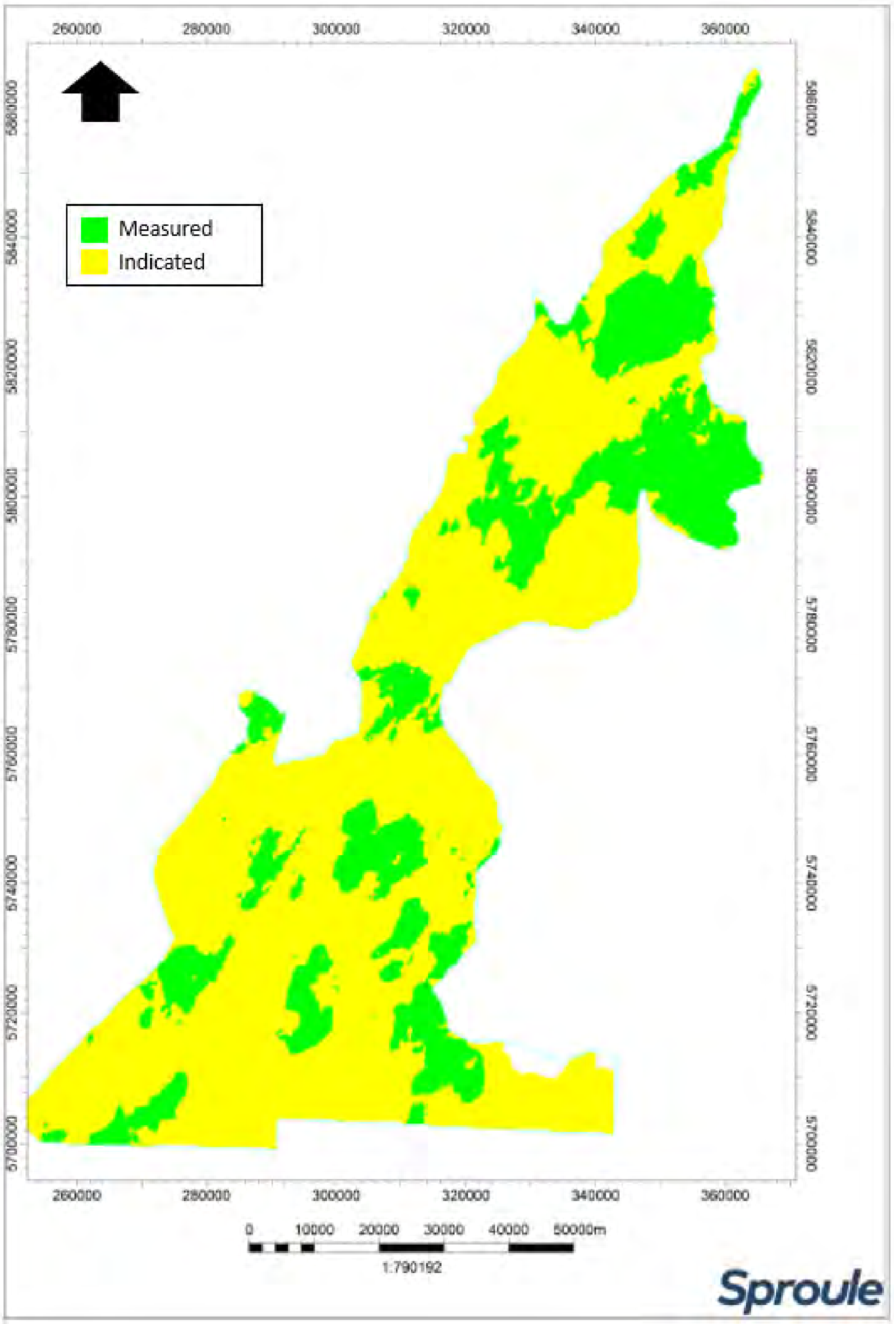
Table 14-7: Clearwater Project Area Total, Measured and Indicated Resource Estimates as a Subset of the Bashaw District

Confidence Category	Original Lithium In Place (t Li)	Original Lithium In Place (t lithium carbonate equivalent)	Original Lithium In Place (t lithium hydroxide monohydrate)*
Clearwater Measured Brine Resource (excluding hydrocarbon pore volumes)	340,200	1,811,100	2,057,100
Clearwater Indicated Brine Resource (excluding hydrocarbon pore volumes)	222,500	1,184,500	1,345,300
Clearwater Measured and Indicated Brine Resources OLIP (excluding hydrocarbon pore volumes)	562,800	2,995,600	3,402,500

Notes to Accompany Brine Resource Tables

1. Brine Resources are reported using the 2014 CIM Definition Standards, and are inclusive of those Brine Resources converted to Brine Reserves. Brine Resources that are not Brine Reserves do not have demonstrated economic viability.
2. The Qualified Persons for the estimate are Daron Abbey, P. Geo and Alex Haluszka, P. Geo, both of Matrix Solutions Inc.
3. The estimates have an effective date of June 20, 2024.
4. Brine Resources are confined within the Leduc Formation within the Bashaw District.
5. Numbers have been rounded.
6. Table 14-7 is not additive to Table 14-6.

Figure 14-8: Visual Representation of Indicated and Measured Resource Volumes Across the Bashaw District



Note: Figure prepared by Sproule Associates Limited, 2024.

14.8 QP Comments on Section 14

Brine Resources were reported using the 2014 CIM Definition Standards. The CIM brine guidance document was not explicitly followed for the reasons discussed in Section 14.2.

The following are comments and discussion from the QPs on factors and risks that may affect the potential development of the Brine Resource:

- The resource estimate methodology is dependant on the assumption that the depleted brine will be reinjected into the host reservoir. It is important to note that emerging regulations in some jurisdictions, and currently in the Project jurisdiction, mandate fluid reinjection as part of brine production schemes. Reinjection brings challenges as well as benefits, as lithium depleted brine will be added to the reservoir and dilution of the resource over time will need to be managed. However, this type of production scheme has been used for oil and gas reservoir development for decades and fluid breakthrough can be managed, with the field optimized in real time. These aspects of production need to be evaluated as part of the reserves analysis, as by-passed brine will need to be excluded from the Brine Reserves versus the Brine Resource;
- The Brine Resource estimate used a geostatistical approach accounting for uncertainty in porosity measurements that leveraged a significant amount of publicly available data from historical petroleum exploration in the reservoir. Therefore, existing porosity, permeability, and grade measurements are still mainly concentrated in the hydrocarbon saturated portions of the reservoir. E3's exploration drilling in the central, water saturated portion of the reservoir, has improved the confidence that the reservoir properties inferred from this data are still representative of the full reservoir area but it is important to note that the relationship of porosity to permeability is variable across the Bashaw District area. The specific factors controlling variability (geological facies, diagenetic processes) were not discretely represented in the current reservoir model other than a linear decrease of porosity versus depth inferred from the broad dataset. While the P50 connected porosity volume may be an overestimate of the actual connected porosity in the reservoir, the QPs believe that the geostatistical approach captured the potential range of uncertainty in connected porosity that could impact the resource estimate which was found to be 12% (P10–P90);
- It is known that there are fractures in the reservoir that make up a component of the connected porosity system. For the purposes of this Report, the porosity system has been treated as a single continuum of porosity, and de-weighted the fracture porosity by using the K90 core permeability measurements rather than the maximum permeability. If the exchange between matrix and fractures is delayed, this could affect the ability to extract the Brine Resource from the matrix porosity. This can be evaluated through additional flow testing and operational monitoring of production.

There are no other environmental, legal, title, taxation, socioeconomic, marketing, political or other relevant factors known to the QP that would materially affect the estimation of Brine Resources that are not discussed in this Report.

15.0 MINERAL RESERVE ESTIMATES

15.1 Introduction

Brine Reserve estimates were reported using the 2014 CIM Definition Standards, and estimated using guidance in the 2012 and 2019 Guidelines.

The proposed mining method will use production wells to pump brine from the Leduc Formation. The reference point for the Brine Reserves is defined as the point of saleable product from the Central Processing Facility.

The Brine Reserve estimate was conservatively modeled and stated as a Proven Brine Reserve for Year 1 through Year 5 of full-scale extraction, and a Probable Brine Reserve for Year 6 through Year 50 of full-scale extraction.

The distinction between Proven and Probable Brine Reserves is based on industry precedent from similar projects.

15.2 Lithium Grade

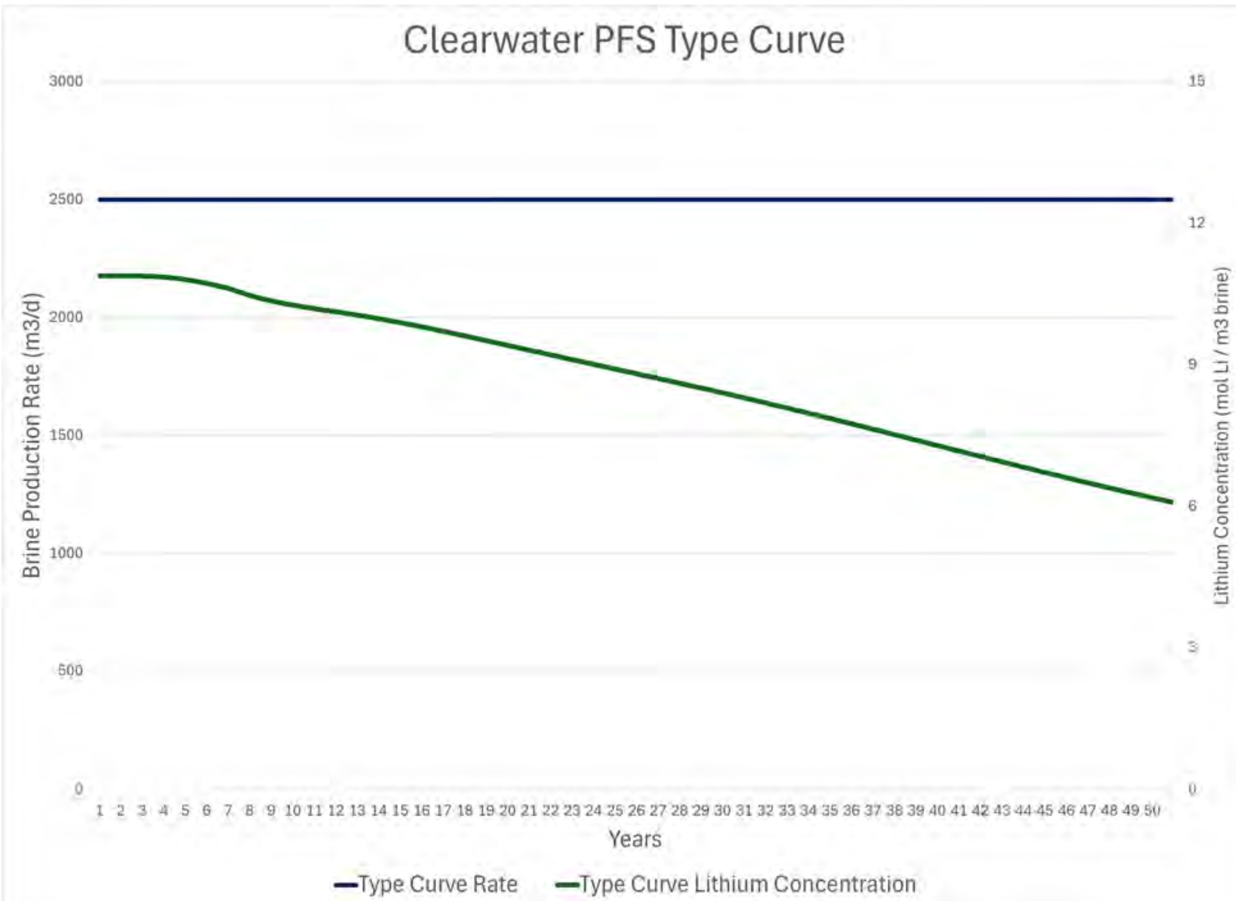
The P50 lithium grade averages 75 mg/L. Within the simulation model (see Section 16), the lithium is represented as a molar mass within the brine, as required for the equations of state functionality that account for lithium diffusion from the original brine to the reinjection brine. The diffusion occurs very slowly within the reservoir and does not make a material difference to the results.

Lithium grade will decline over time as the reinjection brine makes its way to the production well (Figure 15-1).

A conservative approach has been taken which allows both the production and injection wells to be perforated across the entire Leduc Formation thickness, to maximize overall recovery.

Optimization of the production and injection well completions are discussed in Section 16.

Figure 15-1: 2024 PFS Type Curve Showing Rate and Lithium Grade



Note: Figure prepared by E3, 2024.

15.3 Modifying Factors

In estimating the Brine Reserves for the Clearwater Project, the following modifying factors were applied:

- Mining: production wells will be the mining method for this brine-hosted lithium project. The production rollup is based on a type curve that balances production and injection rates for each drainage pattern. Reinjection of spent brine into the formation of origin is a regulatory requirement (AER 090). The physical limitations of drilling and completing the wells were included in the drainage pattern and well pad design. Hydraulic considerations were included in the well design process. Artificial lift mechanisms were evaluated. These modifying factors are discussed further in Section 16;

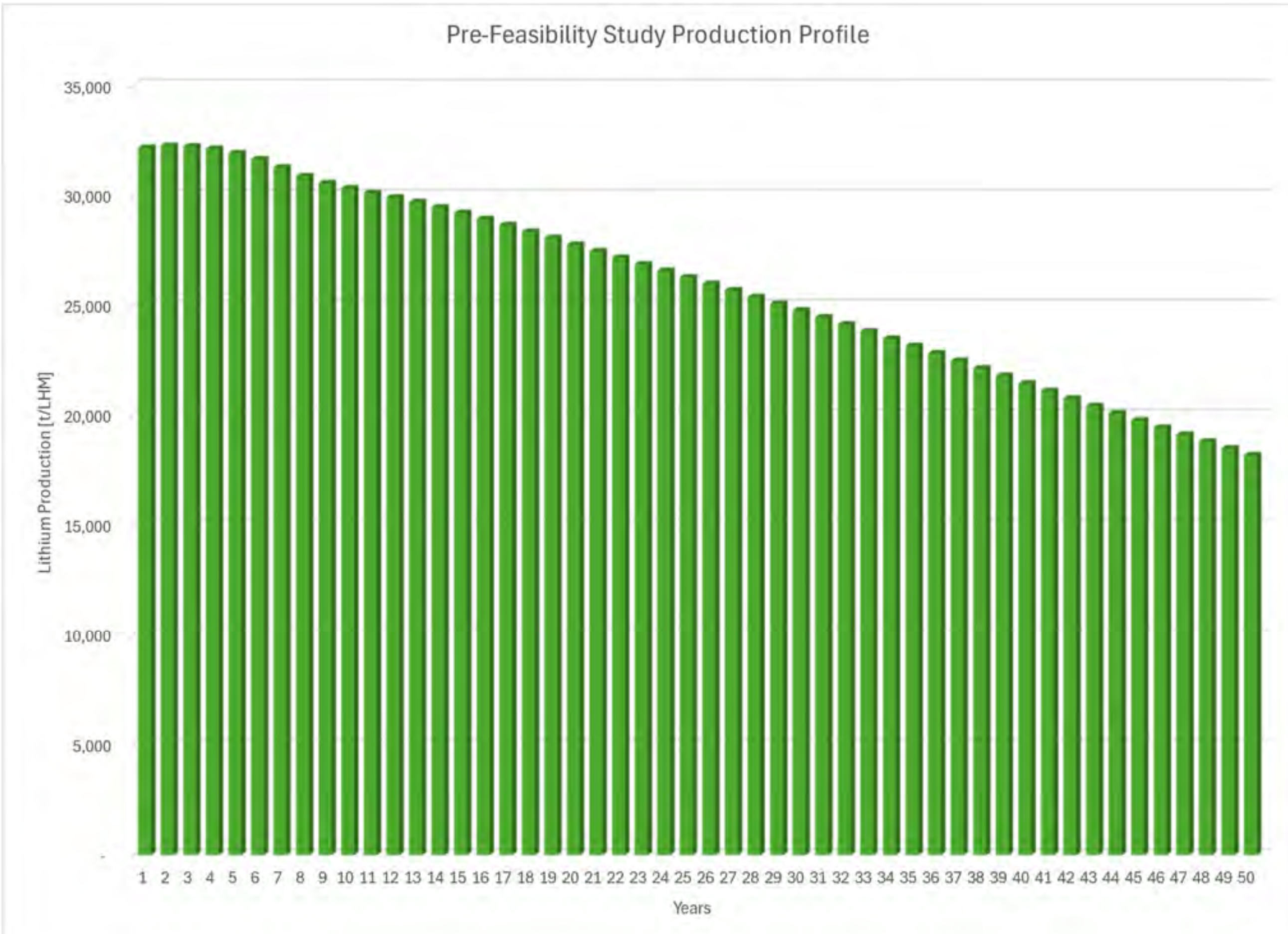
- Processing using direct lithium extraction: two key factors associated with direct lithium extraction and processing through to a battery grade lithium hydroxide monohydrate sales product were the overall "on-time" of the Central Processing Facility, and the lithium losses through the extraction and conversion processes. Both factors were used to determine the facility inlet of 232,500 m^3/d of brine (refer to Section 17 for additional information). The roll-up of the type curve production profiles, including the on-time and lithium recovery factors, are shown in Figure 15-2 and Table 15-1;
- Infrastructure: the infrastructure required for the mineral reserve includes wells, pads, pipelines, and the Central Processing Facility, and are described in Section 18;
- Economic: Section 19 describes the market studies outlining the projected lithium market, with demand exceeding supply. The economic analysis that supports the Brine Reserves is included in Section 22. The Brine Reserve estimate uses an average lithium price of $31,344/t lithium hydroxide monohydrate, and uses negative cash flow as the economic cut-off. A negative cashflow was not realized within the 50-year production life of the project in the 2024 PFS;
- Marketing: the product specification for battery-grade lithium hydroxide monohydrate can vary depending on customer requirements. E3 designed a product specification that is expected to meet or exceed common customer requirements; a subset of the criteria area shared in Section 17;
- Legal, environmental, social and governmental factors: The framework for mineral resource development in Alberta is well established and understood and is discussed in Section 20.
- Infrastructure: in addition to design constraints included in the mining method (wells), pipeline infrastructure was modelled to minimize pressure drop between the well pads and the inlet of the Central Processing Facility. Additional infrastructure considerations are discussed in Section 18;
- Economics: Brine Reserves are by definition constrained by economics. An evaluation of the economics is provided in Section 22, with pricing information in Section 19, and capital and operating costs in Section 21.

15.4 Brine Reserves

Brine Reserves are reported at the point of saleable product from the Central Processing Facility, using the 2014 CIM Definition Standards, and have an effective date of June 20, 2024. The Qualified Person for the estimate is Ms. Meghan Klein, P. Eng., of Sproule Associates Limited.

The Proven and Probable Brine Reservice estimate for the proposed 50-year production period is summarized in Table 15-2, and includes both on-time and lithium recovery.

Figure 15-2: 2024 PFS Production Profile



Note: Figure prepared by E3, 2024.

Table 15-1: Annual Production Rate

Year	Sales Volume (t lithium hydroxide monohydrate)	Year	Sales Volume (t lithium hydroxide monohydrate)
1	32,163	26	25,975
2	32,250	27	25,677
3	32,220	28	25,377
4	32,115	29	25,073
5	31,919	30	24,764
6	31,643	31	24,451
7	31,273	32	24,133
8	30,870	33	23,810
9	30,562	34	23,481
10	30,318	35	23,148
11	30,110	36	22,811
12	29,907	37	22,471
13	29,690	38	22,128
14	29,454	39	21,785
15	29,198	40	21,443
16	28,927	41	21,101
17	28,644	42	20,761
18	28,352	43	20,424
19	28,056	44	20,090
20	27,757	45	19,761
21	27,458	46	19,435
22	27,159	47	19,114
23	26,862	48	18,799
24	26,567	49	18,488
25	26,271	50	18,181

Table 15-2: P50 Proven and Probable Brine Reserves for the Clearwater Project

Clearwater Project Reserves	Li (t)	Lithium Carbonate Equivalent (t)	Lithium Hydroxide Monohydrate (t)
Proven Reserves (initial 5 years)	26,550	141,450	160,700
Probable Reserves (6 to 50 years)	187,200	996,400	1,131,700
Total Proven and Probable	***213,750***	***1,137,850***	***1,292,400***

Note:

1. Brine Reserves are reported at the reference point of the saleable product from the Central Processing Facility, and have an effective date of June 20, 2024. Brine Reserves are reported using the 2014 CIM Definition Standards.
2. The Qualified Person for the estimate is Ms. Meghan Klein, P. Eng., of Sproule Associates Limited.
3. Brine Reserves are reported assuming 2,500 m^3/d/well, initial capital of $2,465 million, average operating costs of $7,250/t lithium hydroxide monohydrate, 92% on-time and 90.4% lithium recovery.
4. Numbers have been rounded.

The Measured and Indicated Mineral Resources (refer to Section 14) correspond to the total producible lithium in place in the Bashaw District and the Clearwater Project Area while the Proven and Probable Brine Reserves represent the recoverable lithium in place, which is a subset of the producible lithium in place demonstrating the portion of producible lithium in place that can be extracted and sold during the planned life of the project.

For the Clearwater Project, the cumulative sales volume of produced lithium for Years 1 through 5 is 160,700 t lithium hydroxide monohydrate, which is ~8% of the P50 Measured Brine Resource in place.

The cumulative sales volumes of produced lithium for Years 6 through 50 is 1,131,700 t lithium hydroxide monohydrate, which represents ~33% of the P50 total Measured + Indicated Brine Resource in place. It is expected that Probable Reserve volumes will convert to Proven Reserve volumes as production and processing data become available. The portion of Measured Resource that has been transferred to Probable Reserve follows precedent for brine-hosted lithium projects.

15.5 Factors that May Affect the Brine Reserves

Factors that may affect the Brine Reserve estimate include reservoir deliverability, lithium concentration, capital and operating expenses, facility on-time factor and lithium processing recovery losses.

15.6 QP Comments on Section 15

Brine Reserves were reported using the 2014 CIM Definition Standards.

The following are comments and discussion from the QP on factors and risks that may affect the potential development of the Brine Reserves:

- The development of the Brine Reserves is dependent on a number of factors including E3's ability to raise sufficient capital to develop the Clearwater Project as outlined in Section 16. Should insufficient capital be available, a smaller-scale development could be considered, which would recover fewer Brine Reserves than those included in the 2024 PFS Report;
- Other factors that could affect development of the Brine Reserves are changes in the assumptions regarding reservoir factors (brine volume, reservoir deliverability, lithium concentration); cost factors (operating and capital costs); processing factors (facility on time, processing losses); lithium market and pricing; supply of materials (both building materials and process materials and chemicals); environmental, social license, and regulatory considerations (approvals and licenses).

There are no other environmental, legal, title, taxation, socioeconomic, marketing, political or other relevant factors known to the QP that would materially affect the estimation of Brine Reserves that are not discussed in this Report.

16.0 MINING METHODS

16.1 Reservoir Development Plan

To produce lithium, the reservoir brine will be pumped to the surface from a production well as produced brine. The produced brine will be processed at the surface to remove the lithium, leveraging direct lithium extraction technology (refer to Section 17). The lithium-depleted brine will be injected into the reservoir using injection wells for pressure support and to maintain the reservoir voidage replacement ratio.

The reservoir development plan is to drill up to five wells from each of 38 pads in the project area, for a total of 93 producers and 93 injectors, each with a rate of 2,500 m^3/d. This approach allows for the centralized gathering of fluids, reducing road and pipeline construction. The inlet volume required to the Central Processing Facility is 232,500m^3/d, which can be met and maintained from the 93 wells for the full 50 years of production, without requiring sustaining well capital.

Multiple well and pump design scenarios were evaluated to determine the optimal design for the project. The optimal was determined by balancing total project costs with executability, including lead-time for casing, tubing, and pumps, to deliver a total bring production of 232,500 m^3/d to the facility inlet. The evaluation included the reservoir deliverability and injection capacity of a variety of well network patterns and downhole spacing scenarios.

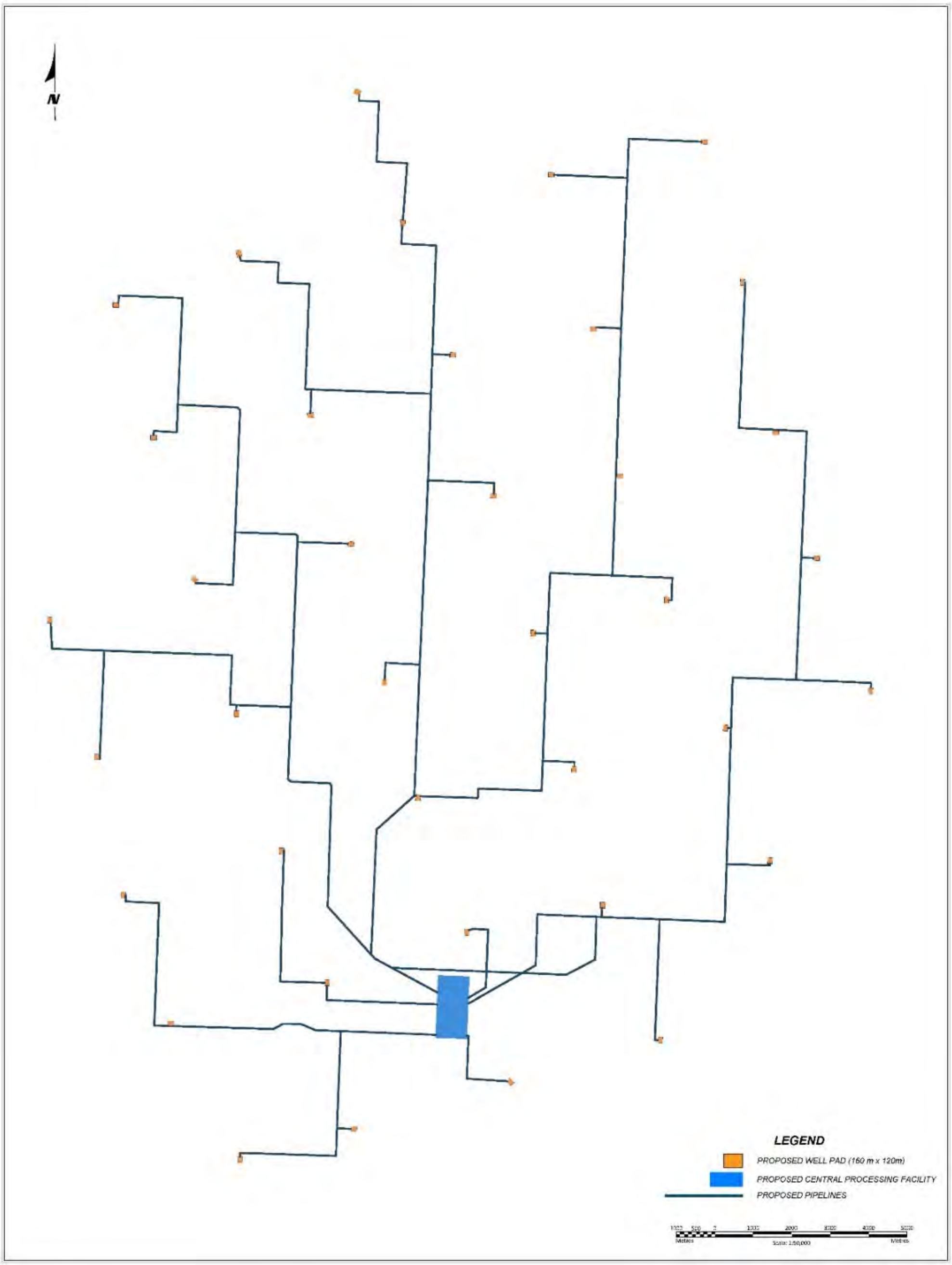
The total field development program will require about 1,300 days of drilling. With six rigs, this would take approximately six months of drill time. This includes the initial survey, clearing, and civil work required for well pad construction and access.

The preliminary locations of the 38 multi-well pads are not being publicly disclosed at this time, to ensure that E3's engagement and stakeholder consultation can occur in the appropriate sequence. The pads will be located using the configuration shown in Figure 16-1.

16.2 Model Overview

A simulation model formed the basis for the reservoir development plan, which in turn formed the basis for the production profile associated with the Brine Reserve estimate. The simulation model was developed using a numerical simulation to generate a type curve for well performance, which was rolled up go generated full project production, and input into an economic model. Processing constraints such as on-time and lithium recovery were accounted for in the cashflow analysis in Section 22.

Figure 16-1: Overview of Proposed Clearwater Project Layout



Note: Figure prepared by E3, 2024.

The simulation model was run using Computer Modelling Group Ltd.'s GEM software, a leading reservoir simulation software for compositional equation of state modelling. The model grid is centered on the 102/01-16-033-27W4 well location, which enabled model calibration using the 2022 flow test data. To be conservative, the model assumes "no flow" boundaries on all sides, meaning that the production rates and lithium grade do not benefit from regional aquifer recharge bringing undiluted lithium grade into the pore space. The production rate was determined by artificial lift constraints, to honour the 2024 PFS design and cost estimates.

16.3 Model Basis

The field development layout in the model is based on a standard "five-spot" well network pattern (Figure 16-2) where the production well is in the center of the pattern and drains the reservoir within its pattern boundary. The boundaries are described as "no-flow" as the fluid on the opposite side of the pattern boundary is pulled towards the production well in the center of its pattern.

The model contains 769,677 grid blocks (35 x 35 x 430). Each block is 66 x 66 x 0.5 m. The planned distance between the production well and the injection well is 1,600 m. The average permeability across the model is expected to be 30 mD. The wells (both producers and injectors) will be vertical within the Leduc Formation, and will be perforated across the full reservoir thickness. Assumptions include a rock compressibility value of 3^{e-6} 1/kPa and a lithium diffusion coefficient of 2^{e-5} cm^2/s.

16.4 Drainage Area

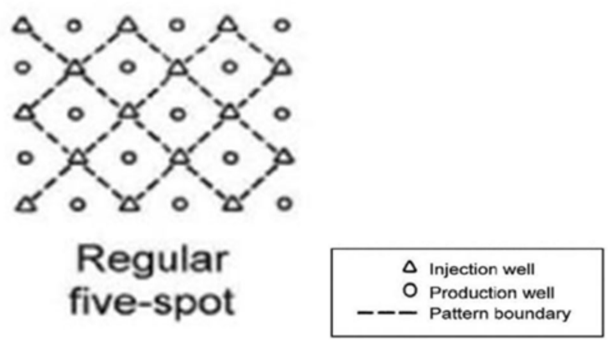
The drainage area for the type curve is 2,262 x 2,262 m, which represents a 2-section equivalent area. Thirty-eight pads, accessing 93 drainage patterns, fit within the project area with more than sufficient buffer sections to account for the small portion of freehold mineral title not owned by E3 or available to E3 via their agreement with Imperial Oil Limited.

16.5 Porosity Cutoff

All blocks with a porosity value below the 2% cutoff were set to zero in the model. This is a conservative approach that excludes the brine volume from those grid blocks, bringing the number of active grid blocks to 478,972.

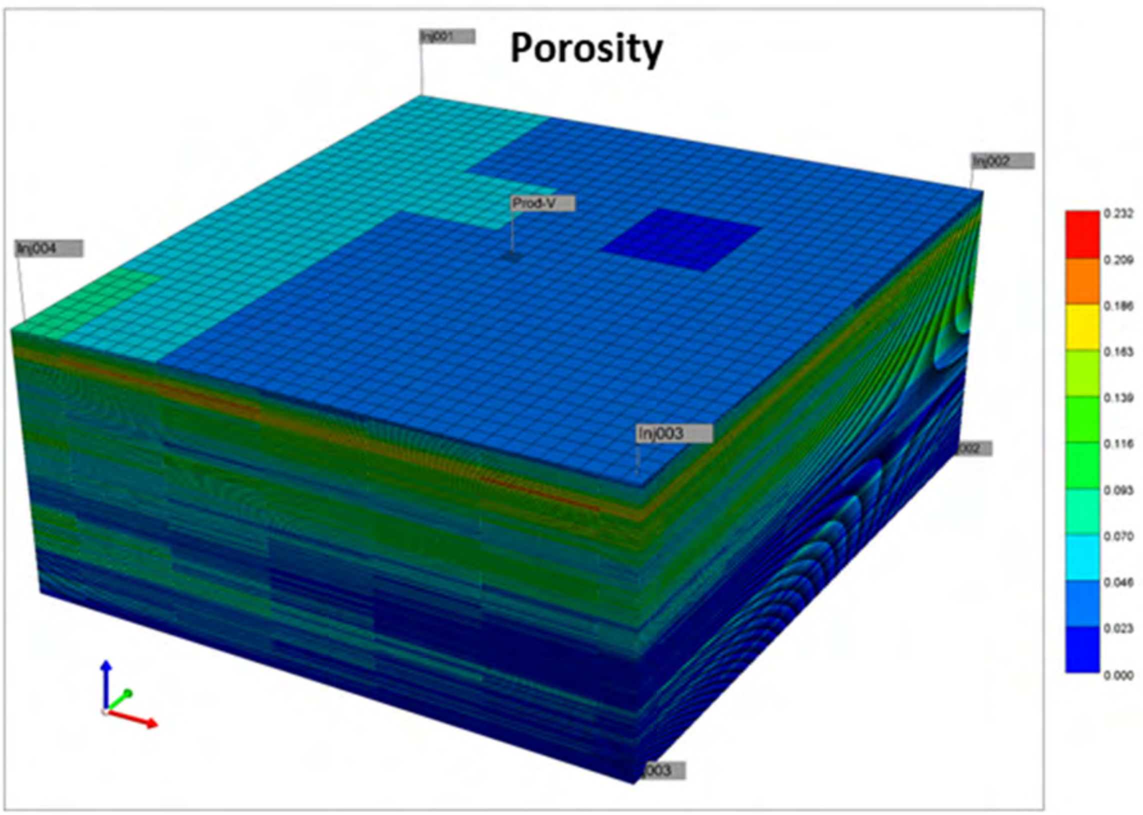
The overall model uses a P50 porosity case from the static model as the volumetric basis for simulations (Figure 16-3). The resource volumes use a 2% effective porosity cut-off at the Indicated level and a 6% effective porosity cut-off at the Measured level.

Figure 16-2: Five-Spot Well Network Pattern



Note: Figure modified by E3 Lithium, 2024.

Figure 16-3: Simulation Model Showing Porosity Across Grid Blocks



Note: Figure prepared by E3, 2024.

16.6 Model Calibration

The model was calibrated using the rates and pressure data from E3's 2022 flow test. The test was performed on the 102/01-16-033-27W4 well and consisted of production at 400 m^3/d for four days, followed by a 10-day build up test, a one-day injection test, and a two-day falloff test.

Having a calibrated model enabled an extensive set of simulation cases to be run to determine the optimal type curve for the project, as well as stress test the various input parameters. These sensitivities resulted in the selection of the field development layout described in Section 16.3 (five-spot pattern, 93 producers and 93 injectors, from 38 pads).

16.7 Well and Pad Design Considerations

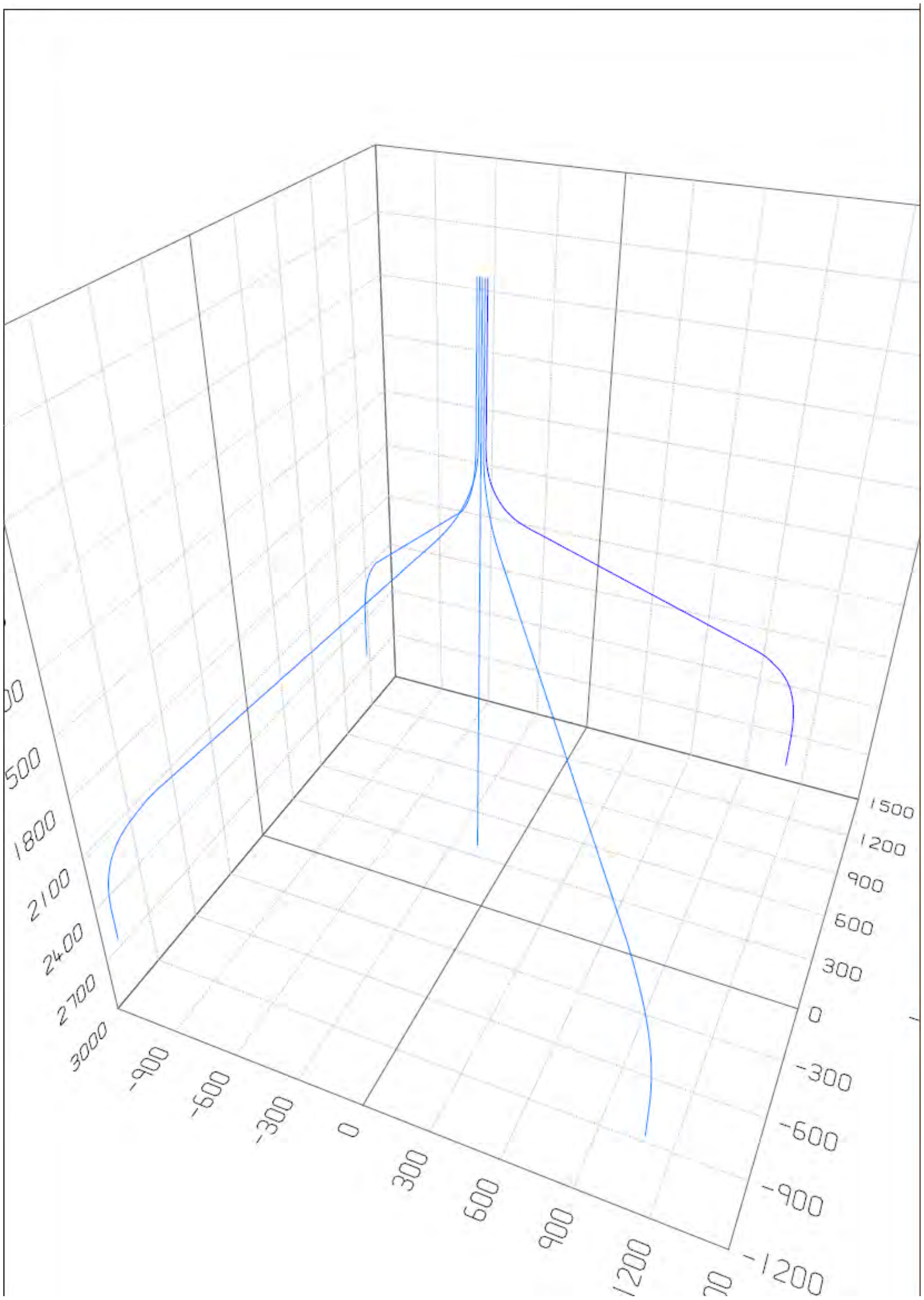
Vertical and deviated wells are required for production and injection. The project layout selection of up to five wells per pad for 38 pads balances the size of the wellbores, the production and injection rates, and the maximum drilling reach to minimize the surface land and environmental disturbance and optimize capital costs.

Drilling wells for brine production and injection will use the same practices and proven technology as hydrocarbon drilling. Preliminary directional drilling programs, including torque and drag analysis, were completed for a type well in the shallowest portion of the Clearwater Project area, to be conservative on the maximum reach (Figure 16-4) and ensure executability. Time to drill each well was estimated at seven days on average, to account for the range of depths expected across the project area.

16.8 Type Curve Optimization

To offset lithium grade decline, a workover is planned for each injection well in Year 5, taking effect in Year 6, across the well network to shut in the top quarter of the reservoir. The upper portion of the Leduc Reservoir has higher porosity and permeability, and the reinjected lithium-depleted brine, will reach the production well through that upper portion more quickly than the lower three-quarters of the reservoir. This workover, applied across the field, will optimize the drainage across each pattern as the lower portion of the reservoir will be swept more efficiently.

Figure 16-4: Directional Profile for Five-Well Pad



Note: Figure prepared by Phoenix Technology Services, 2024.

16.9 Artificial Lift

Lithium-enriched brine from the Leduc Formation will be produced to surface using a downhole artificial lift system installed in the subsurface wells, known as electric submersible pumps. E3 has worked extensively with downhole electric submersible pump vendors to determine the optimal artificial lift system for the brine.

The selected pump consists of multiple centrifugal pump stages, mounted in series, within a housing attached to an electric motor. Each stage contains a rotating impeller and stationary diffusers, using either premium metallurgy or coatings to minimize damage from abrasion or corrosion.

Power will be provided from the surface to the downhole motor via a three-phase electric cable designed for downhole environments. To limit cable movement in the well and to support its weight, the cable will be banded to the production tubing. A step-down transformer will convert the electricity provided via commercial power lines to match the voltage and amperage requirements of the electric submersible pump motor.

The selected electric submersible pump will move brine from the Leduc Formation depth to surface and maintain sufficient pressure to flow into the gathering pipeline system to the Central Processing Facility. The pumps will be set above the producing interval, based on the expected reservoir flowing pressure and rate. Metering, in compliance with AER regulations, will be done on a per well basis for each multi-well pad. The selected pump size is 5 5/8” (142.8 mm), and can be installed in standard oilfield casing of 7 5/8” (193.7 mm). Each pump will be 940 horsepower. The directional plan for the deviated wells, described above, include a straight tangent section for electric submersible pump placement and to manage dogleg severity to optimize the pump life.

16.10 Health, Safety, and Environment

A risk management program that manages the safety of the well with respect to Health, safety and the environment incorporates well integrity considerations. The program will encompass the full well life, from installation through drilling, operation, and finally abandonment. Well integrity will include material selection, drilling practices, cementing practices, preventative maintenance, and monitoring programs, including pad-level hydrogen sulfide detection. The well integrity program will ensure protection of groundwater and zonal isolation within the subsurface.

17.0 RECOVERY METHODS

17.1 Introduction

The Clearwater Project will produce battery-grade lithium hydroxide monohydrate from Leduc Formation brine. The merits of the Clearwater Project and properties of the Leduc brine reservoir support flowsheet development centered around a direct lithium extraction approach to lithium recovery. Brine will be extracted from brine supply wells and transferred by pipeline to the Central Processing Facility. The Central Processing Facility will process 232,500 m^3/d of brine to produce battery grade lithium hydroxide monohydrate at the expected combined lithium recovery performance of 90.4% from the direct lithium extraction technology, lithium refining and conversion steps in the process. The brine will have an average lithium concentration of 75 mg/L ±5 mg/L. The planned production life is 50 years. Applying the Central Processing Facility assumed availability of 92%, the initial facility production rate will be 32,250 t/a.

The processing facility will include the following major process units:

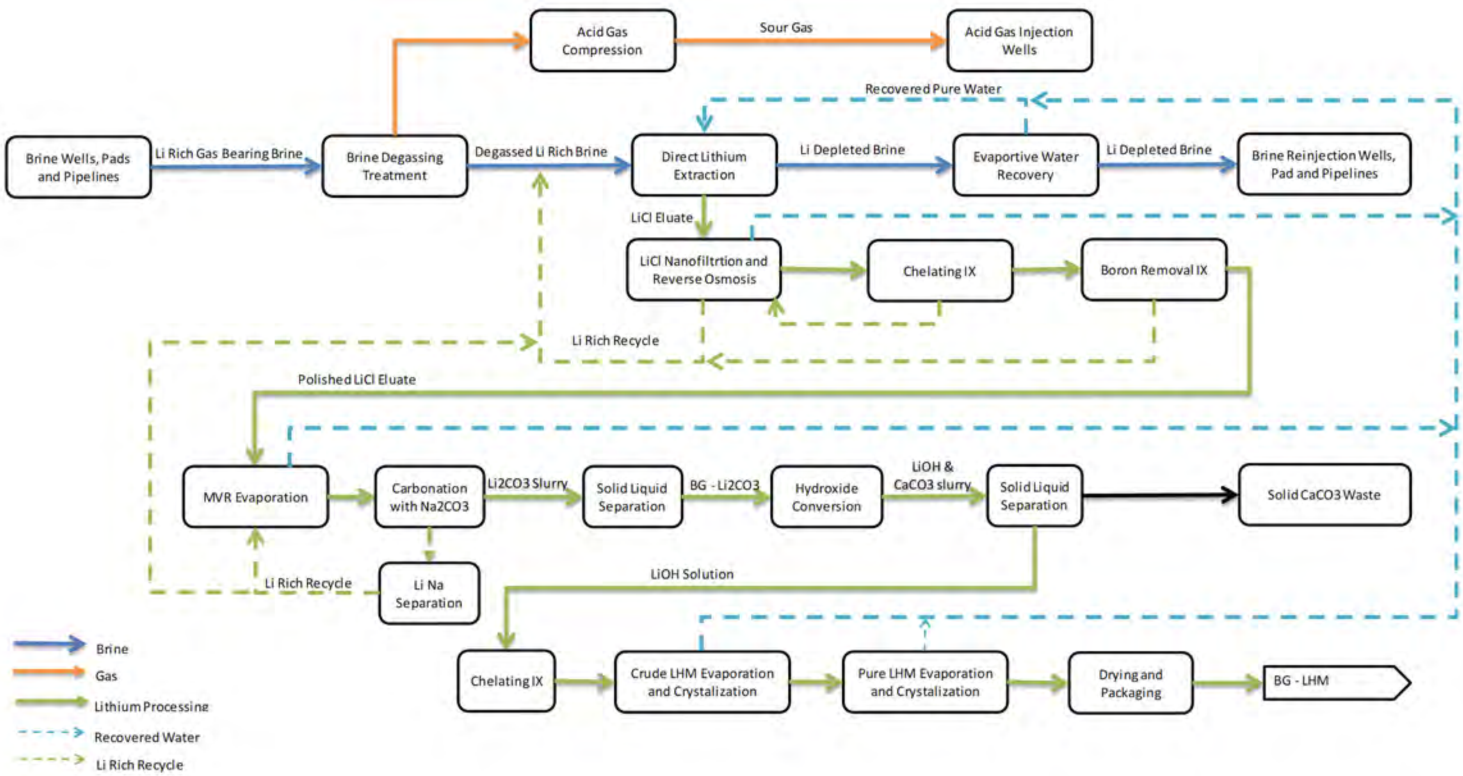
- Brine degassing treatment and acid gas handling;
- Lithium recovery from the brine by direct lithium extraction;
- Lithium depleted evaporative water recovery and reinjection;
- Lithium chloride purification and concentration by nanofiltration, reverse osmosis, ion exchange, and mechanical vapor recompression evaporation;
- Lithium chloride carbonation to lithium carbonate;
- Lithium carbonate conversion to lithium hydroxide monohydrate;
- Lithium hydroxide monohydrate evaporation, crystallization, drying and packaging.

17.2 Process Flowsheet

The overall process block flow diagram for the proposed facility is depicted in Figure 17-1.

The process design criteria are summarized in Table 17-1.

Figure 17-1. Central Processing Facility Block Flow Diagram



Note: Figure prepared by E3, 2024.

Table 17-1: Overall Process Design Criteria

Description	Units	Values	
Feed Conditions			
Brine flowrate	m^3/day	232,500	
Lithium concentration (average)	mg/L	75.5	
Direct Lithium Extraction			
Sorbent type		Aluminate based	
Load volume per sorbent volume	m^3 brine/m^3 sorbent	12 to 22	
Sorbent loading capacity for adsorption and desorption	g Li/L sorbent	1.0–1.5	
Load flowrate	BV/hr	4.0–5.0	
Extraction efficiency	% Li	92	
Eluate flow rate	m^3/hr	800–1,000	
Lithium Chloride Purification and Concentration			
Impurity	mg/L	**DLE Eluate**	**Polished LiCl**
Calcium (Ca)	mg/L	350	<2.0
Magnesium (Mg)	mg/L	40	<2.0
Silicon (Si)	mg/L	<10	<100
Boron (B)	mg/L	250	5.0
Li concentration	mg/L	600–1,000	6,000–8,000
Lithium Chloride Conversion to Lithium Hydroxide			
LiCl to Li_2CO_3 conversion w/recycle	%	98.2	
Li_2CO_3 solid mass flowrate	kg/hr	3,000–3,500	
Li_2CO_3 concentration	g/L	65–70	
Solid–liquid separation method		Centrifuge	
Li_2CO_3 to LiOH conversion	%	96.0	
LiOH solid mass flowrate	kg/hr	2,000–2,500	
LiOH concentration	g/L	30–35	
Solid–liquid separation method		Hydrocyclone Pressure filtration	
Crystallization stages	#	2	
Lithium Production			
Lithium recovery	%	90.4	
Central Processing Facility availability	%	92	

Description	Units	Values
Lithium hydroxide monohydrate production	t/a	32,250
Final product specifications		
Calcium (Ca)	wt %	<0.002
Potassium (K)	wt %	<0.003
Sodium (Na)	wt %	<0.003

Note: DLE = direct lithium extraction; LiCl = lithium chloride; Li_2CO_3 = lithium carbonate; LiOH = lithium hydroxide.

17.3 Brine Treatment and Acid Gas Handling

The brine delivered to the Central Processing Facility is estimated to have the composition as described in Table 7-3. The estimated temperature of the brine upon arrival at the Central Processing Facility will be 70°C.

The brine treatment process will receive 232,500 standard m^3/d of produced fluid from the brine wells and will separate gas from the brine. The gas to water ratio of the brine will be approximately 7:1. The brine will arrive at the separator vessel at a pressure of approximately 800 kPa before being depressurized and flashed between 300 and 400 kPa in the two-phase separator. This flashing will evolve approximately 80% of the dissolved gas from the brine, resulting in a gas stream containing >80% H_2S on a dry basis. The other components will primarily be methane, carbon dioxide and nitrogen, along with small amounts of hydrogen and heavier hydrocarbons. The brine will be further depressurized to near atmospheric pressure in the raw brine tanks. The remaining gas that is flashed off in these tanks will be captured in the vapour recovery unit.

The acid gas from the vapour recovery unit will be compressed and water is condensed out. Following a second compression step, this gas will be combined with the gas from the two-phase separator. The combined gas stream will be compressed and condensed into a dense-phase state for disposal at a wellhead pressure of about 5.5 MPa. Three acid gas disposal wells will be located on the proposed Central Processing Facility site to provide sparing capacity. The disposal formation will be determined following a minimum of one well, with testing across the stratigraphic column, and regulatory applications as required.

The brine coming from the wells will have <350 mg/L total suspended solids with a fine particle size distribution of <20 µm. At this particle size, filtration will not be required prior to direct lithium extraction as particles this size will remain in the brine.

17.4 Direct Lithium Extraction

Lithium chloride will be extracted from the degassed brine through the direct lithium extraction process. The direct lithium extraction process will use an aluminate based sorbent in a continuous separation process with groups of 30 columns operating in a carousel configuration service with four different operating modes (Table 17-2).

Control valves will be used to distribute the fluid to each column depending upon the carousel stage. There will be no rotating equipment or rotary valves distributing flow in the continuous separation process. The sorbent beds and column will be fixed and flow will be manipulated with dedicated valves.

17.5 Lithium Chloride Purification and Concentration

The lithium chloride (LiCl) eluate stream from the direct lithium extraction phase will move through purification and concentration processes to remove contaminants and recover water. Suspended solids will be removed by multimedia filtration and ultrafiltration upstream of the membrane process area. Within the membrane process area multistage reverse osmosis and nanofiltration will be used to incrementally concentrate and purify the LiCl eluate. The reverse osmosis stage will recover 78% of the water received at the membrane process and will recycle this recovered water to the direct lithium extraction to be used for desorption. The LiCl eluate will flow through multi-stage nanofiltration to separate divalent calcium and magnesium cations from the LiCl eluate. The LiCl eluate will be discharged from the reverse osmosis and nanofiltration membranes will be a lithium concentration of approximately 6,000 mg/L with a remaining 6 mg/L Ca and 6 mg/L Mg.

The calcium- and magnesium-enriched rejection stream will contain 99.8% of the calcium and magnesium that enters the membrane process. This reject stream will contain about 4% of lithium, which will be recycled and blended with the brine upstream of the direct lithium extraction to provide additional lithium recovery.

The LiCl eluate stream from the membrane process will be polished by chelating ion exchange resin to remove the remaining calcium and magnesium cations to ≤1 mg/L. Approximately 42% of the boron will be removed through the membrane process. The ion exchange vessels will be operated in groups of three in a lead-lag-regeneration arrangement. Chelating resin will be regenerated with hydrochloric acid and sodium hydroxide. The calcium- and magnesium-enriched regenerant stream will be recycled to the front and blended with the LiCl feed to the first reverse osmosis to allow the water to be recovered from this stream and to concentrate all calcium and magnesium into a single stream. The lithium recovery through the membrane process is forecast to be 96%.

Table 17-2: Carousel Configuration Service Operating Modes

Operating Mode	Note
Adsorption	Lithium containing brine will be pumped through the sorbent beds loading the sorbent with lithium and chloride ions. Columns will be configured so that the columns with recently regenerated sorbent initially operate as parallel single stages. As the sorbent loads with lithium and approaches maximum loading less sites will be available for adsorption therefore the column configuration will be changed by actuating vales and a lag column will be placed in series to capture any breakthrough. This system will allow the process to reduce the total number of columns required while managing the column operating pressure. The majority of the vessels will be operating in adsorption at any given time.
Brine displacement rinse	Once the sorbent bed is fully loaded with lithium and chloride, the brine will be rinsed from the bed using desorbed LiCl solution in preparation for desorption
Desorption	Recovered water from the process will be used to desorb the lithium and chloride ions from the sorbent. The eluate stream leaving the sorbent bed will have approximately 600–1,000 mg/L of Li at approximately 93% recovery with minimal contaminants. The contaminant rejection will be >99% for sodium, calcium and magnesium, and 92.1% for boron. The desorption operating mode will be completed in series to maximize the efficiency of desorption and decrease the water used in this mode.
LiCl displacement rinse	The eluant in the sorbent bed will be displaced from the column and recycled to regenerate the sorbent and prepare the column to receive lithium rich brine. The direct lithium extraction process will produce no waste streams and will require no chemical treatment.

Polished LiCl solution free of calcium and magnesium will flow from the chelating ion exchange to a boron ion exchange resin for removal of boron to <5 mg/L. The boron removal resin will be regenerated with hydrochloric acid and sodium hydroxide. The boron regenerant will include approximately 1% of the lithium and will be recycled to the brine feed. The ion exchange vessels for boron removal will also be operated in a continuous separation process built around teams of 12 resin columns.

The final polished LiCl eluate stream will report to a mechanical vapor recompression unit for additional water removal. Approximately 75% of the solution is evaporated and the condensate recovered from the mechanical vapor recompression evaporator is reused within the process. The mechanical vapor recompression will increase the concentration of the lithium to 24 g/L.

Lithium containing recycle streams will be combined with the fresh brine in the feed to the direct lithium extraction process. The flow rate of the combined recycle streams will be about 1.3% of the brine flow rate with negligible effects of recycling calcium, magnesium, boron, and sodium, due to the high rejection rate of the sorbent.

17.6 Lithium Chloride Carbonation

The purified and concentrated LiCl eluate will leave the mechanical vapor recompression and be directed into the carbonation reactor where it will be combined with a saturated sodium carbonate (Na_2CO_3) solution to precipitate lithium carbonate (Li_2CO_3) and generate a sodium chloride (NaCl) solution. The equation is:

- $2LiCl + Na_2CO_3 = 2NaCl + Li_2CO_3 \downarrow$

The Li_2CO_3 precipitate stream will be thickened then dewatered in a centrifuge. The dewatered precipitate will be re-slurried in a washing kettle where hot recovered water will be used to remove impurities. The resulting slurry will be transferred to the final centrifuge produce battery-grade product.

The carbonation process will convert 88% of the lithium from LiCl to Li_2CO_3. The NaCl solution from the carbonation reactor, known as the mother liquor, will contain approximately 14% w/w NaCl and a significant concentration of soluble Li_2CO_3.

A mother liquor recovery system is designed to enhance lithium yield by employing a continuous separation process using a specialized organic resin to extract lithium from the mother liquor. The mother liquor recovery system will recover approximately 85% of the lithium in the mother liquor for a total conversion of approximately 98% of lithium into solid Li_2CO_3. The spent mother liquor will be recycled back to the brine feed tank to recover unconverted lithium.

17.7 Conversion to Lithium Hydroxide

The solid lithium carbonate will be continuously fed to an agitated tank, where it will be mixed with process condensates to create an aqueous slurry. The slurry will be pumped to a set of lithium hydroxide conversion reactors. The setup of three conversion reactors in series will enable the required residence time with a by-passing possibility of one of the reactors at any time.

Hydrated lime slurry will be added at a controlled rate to the first reactor and will react with the lithium carbonate to form soluble lithium hydroxide and sparingly soluble calcium carbonate via a double replacement reaction. The reaction will occur at elevated temperature to improve reaction kinetics and decrease calcium carbonate solubility. Slurry from the conversion will be fed to pressure filtration to remove calcium carbonate solid with lithium hydroxide containing filtrate pumped to the polishing filtration step.

- $Li_2CO_3 + Ca(OH)_2 = 2LiOH + CaCO_3 \downarrow$

The ion exchange process will target the removal of multivalent impurity metal ions (mainly Ca^{2+}) from solution with chelating resin. Ion exchange will be completed in three fixed-bed columns operating as a lead-lag-regeneration arrangement, in the same manner as the chelating ion exchange vessels downstream of the carbonation process.

Regeneration will include a displacement wash with cooled process condensate to displace the LiOH solution from the vessel. After the first displacement wash, a short backwash with process condensate will be performed to backwash the resin bed and remove any air bubbles and possible channeling. The backwash return water will also be collected and recycled to the upstream conversion process. The resin will be washed with an excess of hydrochloric acid solution to regenerate. The acidic regenerate stream, containing mainly calcium, as chlorides, will be combined with the depleted brine stream. This will be followed by a second displacement wash with cooled process condensate before neutralization.

Lithium hydroxide from the ion exchange will be concentrated in tubular falling film evaporator before being crystallized in a mechanical vapor recompressor. The concentrated lithium hydroxide at about 11% will be extracted from the falling film evaporator and pumped to a hydrocyclone where solid particles will be separated from the liquid by centrifugal force to be used as falling film evaporator seeding material. The hydrocyclone overflow will be collected and then filtered in the candle filter to avoid the transfer of fines into the crystallization process.

The undersaturated feed solution coming from the falling film evaporator unit will be collected in a crude LiOH mother liquor tank, which will be equipped with an agitator to provide sufficient mixing of the solution. The solution will be pumped to the lithium hydroxide monohydrate forced circulation crystallization unit. The crude lithium hydroxide monohydrate forced circulation crystallization unit will crystallize an unpurified lithium hydroxide monohydrate. The LiOH solution will be evaporated, and solids will be crystallized in the forced circulation crystallizer.

The vapor produced from this unit will be separated from droplets via a demister. The droplet-free vapor will be recompressed via the mechanical vapor recompressor turbofans and reused as heating media for the heat exchanger.

The crystal suspension from this unit will be pumped to the hydrocyclone. The underflow will enter the washing thickener and be washed in a counter-current flow against a portion of the fresh mother liquor from the falling film evaporator filtrate tank. The overflow of the washing thickener will be collected in a storage tank equipped with an agitator to provide sufficient mixing of this solution. The solution will be pumped to a candle filter to remove turbidity from the solution. The filtered solution will then be transferred to the mother liquor tank.

The washed and thickened underflow of the wash thickener will be separated by a pusher centrifuge where crystals will be separated from the mother liquor and washed with condensates. The filtrate from the pusher centrifuge will be collected in the crude LiOH mother liquor tank. The wet cake will be discharged to the dissolution tank where the washed crystals will be redissolved with condensate.

The crude lithium hydroxide monohydrate will be dissolved in an agitated tank with condensate. The overflow from this dissolution tank will be transferred into a pure LiOH overflow tank. The dissolved crude will then be pumped to a candle filter to remove fine particles. If any particles are separated, they will be collected in a filter discharge tank. The filtrate will then be collected in the pure LiOH filtrate tank. The filtrate will be pumped to the preheater to be heated by the process condensate coming from the pure LiOH crystallization unit. The dissolved and heated crude will be transferred to a pure LiOH mother liquor tank to be crystallized in the pure LiOH crystallization unit to reach the expected concentration.

The pure lithium hydroxide monohydrate forced circulation crystallization unit will crystallize a purified lithium hydroxide monohydrate. The feed coming from the crude LiOH crystallization unit will be transferred from the mother liquor tank to the pure LiOH crystallizer. The LiOH solution will be evaporated, and solids will be crystallized in the forced circulation crystallizer.

The crystal suspension from the pure crystallizer system will be withdrawn by pump and transferred to a hydrocyclone to pre-thicken the slurry. The hydrocyclone overflow will be collected and recycled back to the crude crystallizer mother liquor tank and to the crude dissolution tank. The underflow of the pure LiOH hydrocyclone will be transferred into the pusher centrifuge where crystals will be separated from the mother liquor and washed with condensates and the overflow will be fed back to the pure LiOH mother liquor tank. The wet crystals will be discharged to the conveyor and then transported to the dryer system.

The dryer system will begin with a closed cycle static fluid bed system including a supply fan processing carbon free air. The product will enter the fluid bed into the first-stage back mix zone, where it will be fluidized and dried using heated air. The dry product will overflow into the second-stage cooling zone, where cool and dry gas will lower the product temperature to meet the design requirement. The final product will be collected at the fluid bed discharge to the packaging system by airlock.

Process condensate streams from the falling film, crude, and pure crystallizer systems will be collected in process condensate collection tank. The process condensate will be used in a pressurized ring line for redissolving crude crystals, spraying demisters in the crude and pure crystallizers, spraying demister in the falling film evaporator, de-superheat (return to saturation) steam for the mechanical vapor recompression turbofans, as well as seal water for mechanical seals via a separate seal water cooler. The condensate surplus will be reused in the direct lithium extraction process for desorption.

17.8 Lithium Hydroxide Monohydrate Packaging

The dried lithium hydroxide product will be packaged in bulk bags. Once the lithium hydroxide product exits the drier, the product will be transferred to one of two product storage silos through a closed-loop carbon dioxide-free system. Screening of the product will take place before the product enters the silos. The oversized material will be returned to the upstream process. The product packaging system will include an automated bag-filling station at the bottom of each silo. Nitrogen conveyance systems will ensure a carbon dioxide-free environment during the product transfer, storage and packaging processes. The filled bulk bags will be placed on a pallet and conveyed to the loading station for storage and transportation.

17.9 Lithium Depleted Brine

To maintain the water balance and satisfy the pure water demand, water will be recovered from the lithium depleted brine using falling film evaporators. The evaporators will operate in parallel, each in a once through configuration to minimize the retention time of the brine in the evaporator. The evaporator will run under vacuum to minimize temperature change of the brine. The water recovered from the brine will be combined with the other pure recovered water to meet the Central Processing Facility pure water requirements.

The lithium depleted brine downstream of the water recovery evaporator will be pumped to reinjections wells. The lithium-depleted brine will be a combination of the brine pumped to the Central Processing Facility and the lithium-rich recycled streams that will be added to the brine upstream of the direct lithium extraction process. It is estimated that the disposal brine will remain a Class 2 fluid, as defined by the Alberta Energy Regulator, and can be readily reinjected back into the Leduc Aquifer.

17.10 Equipment

The following equipment will be required across the major process areas:

- Brine degassing treatment and acid gas handling: four 2-phase separators, four gas compressors, three vapour recovery units;
- Lithium recovery from the brine by direct lithium extraction: direct lithium extraction vessels, ion exchange vessels, mother liquor recovery unit;
- Lithium depleted evaporative water recovery and reinjection: three evaporators; 14 reinjection pumps;

- Lithium chloride purification and concentration: nanofiltration membrane unit, reverse osmosis membrane unit, ion exchange, and mechanical vapor recompression evaporation;
- Lithium chloride carbonation to lithium carbonate: filtration vessels; carbonation reactor; soda ash silo and slurry system;
- Lithium carbonate conversion to lithium hydroxide monohydrate: six mechanical vapour recompression evaporators, two centrifuges, three hydrocyclones; hydroxide conversion reactor, a falling film evaporator, two washing thickeners, acid storage system, caustic storage system, lime silo and slaking system;
- Crystallization, drying and packaging: two forced circulation crystallizers, a drying system, and a packaging system.

17.11 Energy, Water, and Process Materials Requirements

17.11.1 Energy

Energy requirements are discussed in Section 18.2.

17.11.2 Water

Under normal operations, the Central Processing Facility will not be reliant on fresh water to meet the process water demands. All process demands for pure water will be met by recycling reverse osmosis and evaporator distillates.

17.11.3 Reagents and Consumables

The hydrated lime slurry will be prepared from slaked quick lime. Solid quick lime (calcium oxide) will be stored as a solid powder in silos. The solid quick lime will be blended with pure water in a temperature controlled slaker to achieve full conversion to hydrated lime (calcium hydroxide).

Raw materials used in the process will include hydrochloric acid and sodium hydroxide for pH control and ion exchange regeneration, soda ash (Na_2CO_3) for the carbonate conversion process and lime (CaO) for hydroxide conversion process. The estimated raw material requirements for the process are summarized in Table 17-3.

Table 17-3: Reagent Consumption Forecasts

Description	Consumption Rate	
	(kg/hr)	(t/a)
Hydrochloric acid (31 wt%)	7,733	62,322
Sodium hydroxide (50 wt%)	2,140	17,247
Soda ash	7,808	62,926
Quick lime	3,237	26,088

18.0 PROJECT INFRASTRUCTURE

18.1 Introduction

The key infrastructure required in support of the mine plan includes:

- Power supply (grid tie-in and third-party cogeneration unit);
- Access road(s);
- Storm water pond;
- Central Processing Facility (gas compression and injection; pre-treatment – degassing; direct lithium extraction and post-direct lithium extraction treatment; lithium hydroxide plant);
- Office space, control room, laboratory, security, first aid;
- Warehouse for storage of spares and sales product;
- Communications (fibre-optic cable);
- Multi-well pads;
- Pipelines.

A conceptual infrastructure location plan was provided as Figure 16-1. A conceptual layout plan for the Central Processing Facility is shown in Figure 18-1.

18.2 Power Supply

The Central Processing Facility will require an electrical power supply of approximately 85 MW, and field production infrastructure, dominated by downhole pump requirements, will require approximately 80 MW.

E3 is seeking a third-party to construct and operate a cogeneration facility to be located adjacent to the Central Processing Facility to supply power. E3 will enter into a power purchase agreement with the third-party supplier.

The cogeneration facility will be connected to an existing transmission power line in close proximity to the Central Processing Facility to provide redundancy and reliability for power supply in the event of a cogeneration facility outage. Power for the well pads will also be supplied by the cogeneration facility through power infrastructure built and operated by a local power distribution company.

Figure 18-1: Conceptual Layout Schematic of the Central Processing Facility

Note: Figure prepared by E3, 2024.

The facility will include natural gas fired turbines. The turbines will operate in a combined cycle to maximize generation efficiency, and a portion of the steam generated from waste heat will be used within the Central Processing Facility to satisfy all utility steam requirements during normal operations.

Carbon dioxide capture is being investigated on the turbine exhaust stacks. The installation of emissions recovery equipment will be the responsibility of the third-party supplier. E3 will receive high pressure, dense phase carbon dioxide and retain responsibility for sequestration. The carbon dioxide is expected to be disposed in the same formation as the solution gas separated in the pre-treatment phase of the Central Processing Facility.

An operating cost for power consumed was included in the operating cost estimate (see Section 21). The power cost includes the carbon dioxide capture and associated compression equipment but excludes sequestration wells.

18.3 Wells

The brine will be extracted from the Leduc reservoir using a series of wells (see Section 16). A total of 38 pads will be built, with an initial approximate size of 160 m by 120 m. Each pad will host five wells, each drilled using direction techniques in an "S" pattern so that they intersect the Leduc reservoir vertically and will be completed across the entire Leduc interval. The well configuration will be four producers and one injector for 19 of the pad locations and one producer and four injectors for the remaining 19 pad locations for a total of 93 producers and 93 injectors across the Project.

Once the drill activities are complete, the production wells will have an electric submersible pump installed and each pad site will have a transformer, local motor control centre and electrical building. The pipeline will be tied into the pad site and further tied into the main pipeline gathering system for the Central Processing Facility.

Upon completion of all well drilling and equipment installation, the well pad will be reclaimed to an operating size of approximately 100 x 80 m. The subsoil and topsoil removed from the site will be stored for the duration of the well pads' service life. Once the wells on the pad are no longer in service, the pad site will be reclaimed back to its original use using the stored subsoil and topsoil. All well pads will be completely reclaimed upon decommissioning.

18.4 Pipelines

Brine from the well network will be collected in a brine production gathering system. The major constraints on the gathering system design are the electric submersible pump performance characteristics, the plant inlet operating pressure and the maximum nominal pipeline diameter available in the fiberglass materials selected for the pipelines.

The produced brine contains dissolved gas at reservoir conditions, and at the pipeline conditions gas evolves as the pressure drops. The pipeline therefore will operate in a two-phase flow regime along its length. This is not uncommon in the oil and gas industry, and operating a two-phase pipeline operation is well understood.

The brine production and reinjection pipelines will be constructed of a fibreglass-reinforced plastic composite material that is resistant to corrosion and erosion. The pipelines will be installed along pipeline right-of-way corridors that will be negotiated with surface landholders and approved through the regulatory process.

The pipeline corridors and trench for the brine supply pipelines will be shared with the brine reinjection pipeline network. Based on the 2024 PFS design, the brine supply pipelines and the brine reinjection pipelines will range in diameter from 8-inch (20.3 cm) to 24-inch (61 cm). There will be approximately 200 km of brine production pipelines and about 200 km of brine reinjection pipelines.

An active leak detection system will be installed in the trench with the gathering and reinjection pipelines. The fiber optic leak detection system will be capable of very low flow leak detection and it will also serve as the communication system enabling remote operation from the Central Processing Facility control room.

The pipelines will be buried in the trench, as is common for oil and gas production pipelines. For significant road and water-course crossings, a process of directional drilling, installing a casing pipe and pulling the pipeline through the casing will be used. The pipeline segments will be below the frost line, and will be insulated below grade using a spray-applied polyurethane foam insulation.

18.5 Central Processing Facility

18.5.1 Logistics

The potential proposed Central Processing Facility site location was selected due to its strategic location, which will benefit from its proximity to existing infrastructure including roads, and rail, facilitating efficient transport of chemicals and supplies to the Central Processing Facility and from the Central Processing Facility to offtake customers. The specific location has not been included in this Report and will be outlined upon completion of the local stakeholder engagement adjacent to the Central Processing Facility location; local stakeholder engagement is currently underway.

E3 hired an external company to complete a comprehensive assessment of transportation and logistic options for operation in both the short and long term.

The options reviewed for transport of materials required during operation to the proposed site were:

- A new rail line: construct a new rail line connecting the Central Processing Facility to either the Canadian National or Canadian Pacific + Kansas City Southern mainline to load and unload reagents and finished products directly from or to the rail at the plant site;
- New transload terminal: build a new transload facility connected to one of the railways' mainlines and use trucks to access the Central Processing Facility;
- Existing transload site: use or upgrade an existing transload site. Use trucks to transport reagents and lithium hydroxide monohydrate product between the transload site and the Central Processing

Facility. There are multiple transloading providers in the area within a radius of 100 km that could be used to transload the various products.

The recommended and selected option for the 2024 PFS was to use an existing transload site and truck materials to and from the Central Processing Facility.

18.5.2 Roads

The potential proposed Central Processing Facility location will be located strategically within 50 km of existing high load corridors with 9.0 m height clearance for transport of heavy equipment during construction and deliveries to and from the proposed site during operation.

There are paved roads to the potential proposed Central Processing Facility site, save for a final section. This will be upgraded as part of the project, and an allowance has been included in the capital cost estimate for the upgrade.

18.5.3 Waste

Known waste streams include gas and calcium carbonate solid waste. Solid waste will be transferred by truck to a local waste handling disposal facility. Gas will be injected into disposal wells co-located on the proposed Central Processing Facility site.

There is a local market for calcium carbonate and E3 is exploring ways to sell this product into the cement industry and eliminate this product as waste. This would enable the project to generate no physical waste product. The viability and cost benefits of selling this product have not been included this Report, the cost estimate in Section 21 or the cashflow in Section 22, and remains a potential opportunity for the project.

18.5.4 Natural Gas

Power for the Central Processing Facility and the well pads will be from the cogeneration facility to be located adjacent to the Central Processing Facility. Natural gas will be sourced from local distribution and/or transmission infrastructure and delivered to site. A new natural gas pipeline up to 25 km in length will be constructed.

18.6 Support Services

18.6.1 Topsoil Stockpiles

Topsoil will be conserved into stockpiles to be located at both the well pads and the Central Processing Facility.

18.6.2 Buildings

Non-process buildings at the Central Processing Facility will include:

- Office space;
- Control room;
- Warehouse for storage of spares and sales product;
- Laydown area;
- Laboratory;
- Security;
- First aid.

18.6.3 Camps and Accommodation

The Central Processing Facility will be located in close proximity to the Calgary–Edmonton corridor. Personnel to construct, operate, maintain, and support the operation are expected to come from local towns and cities, and a camp will not be required at the Central Processing Facility.

Parking during operation with plugins for block heaters and electric vehicles will be provided at site.

18.6.4 Water Supply

Potable water will be trucked into the plant site for domestic and laboratory use.

18.6.5 Wastewater Disposal

Domestic and sanitary (grey and black) wastewater will be stored at the Central Processing Facility and trucked from the plant site to a local municipality for treatment.

18.6.6 Fire Protection

A fire protection system, including fire detection and water distribution, will be provided. The fire protection system will adhere to the National Fire Protection Association standards. There is an opportunity to use stormwater collected in the site's stormwater collection pond as firewater with appropriate regulatory approval.

18.6.7 Stormwater Management

Surface water will be collected on site in a stormwater pond. Runoff not collected in the pond will be directed around the site using ditches and culverts. Natural grades will be used on the site wherever possible to minimize cut and fill requirements at the Central Processing Facility.

18.6.8 Security

The Central Processing Facility will be fenced and operations personnel will be present on site 24 hours per day. A truck scale will be located at the plant to audit delivery volumes trucked to and from site.

18.6.9 Safety

Safety will be the top priority for the operation. First aid will be provided on site at the Central Processing Facility, and safety training will be provided to all staff.

19.0 MARKET STUDIES AND CONTRACTS

19.1 Market Studies

19.1.1 Introduction

Lithium is a key element in the production of batteries for electric vehicles, consumer electronics, and grid-scale energy storage. Lithium is the lightest and most reactive alkali metal and typically found in mineral rich brines or in minerals like spodumene and lepidolite found in pegmatites. Figure 19-1 shows a simplified diagram of the lithium value chain from the source and extraction to the main intermediate compounds and typical applications.

Given the wide variety of lithium products in the market, a common unit of measurement has been devised for easier comparison; the lithium carbonate equivalent. This is also the unit that is typically used to measure the size of the global lithium market. Lithium hydroxide and lithium hydroxide monohydrate are the other common lithium products in the market.

The demand for lithium has been growing rapidly in recent years, driven by the global transition to sustainable energy solutions and the rapid adoption of lithium-ion batteries. Market studies indicate a robust upward trend, with lithium demand expected to triple by 2030.

However, the supply of lithium in the long term may not be sufficient to meet the rising demand, especially for high-quality battery-grade lithium compounds. The majority of current lithium production comes from brine extraction in South America and hard rock mining in Australia. These producers are facing challenges in scaling operations to the required levels, leading to potential supply shortages. This scenario presents a compelling opportunity for new projects to play a crucial role in bridging the supply-demand gap and potentially reduce the environment and social impacts of lithium production.

While global economic growth was severely affected by the COVID-19 pandemic in 2020, Russia’s invasion of Ukraine in 2022 and the inflation-driven dip in 2022–2023, the current market drivers of battery demand and raw material supply override the general macroeconomic fluctuations.

The global economic growth (measured by real gross domestic product, purchase power parity) according to the International Monetary Fund (IMF) decreased to 3.0% in 2023 before rising to 3.2% in 2024 and 3.2% in 2025. The expected higher overall global economic growth has the potential to boost consumer demand for grid-scale energy storage and consumer products such as power tools.

Figure 19-1: Lithium Compound Development and Use

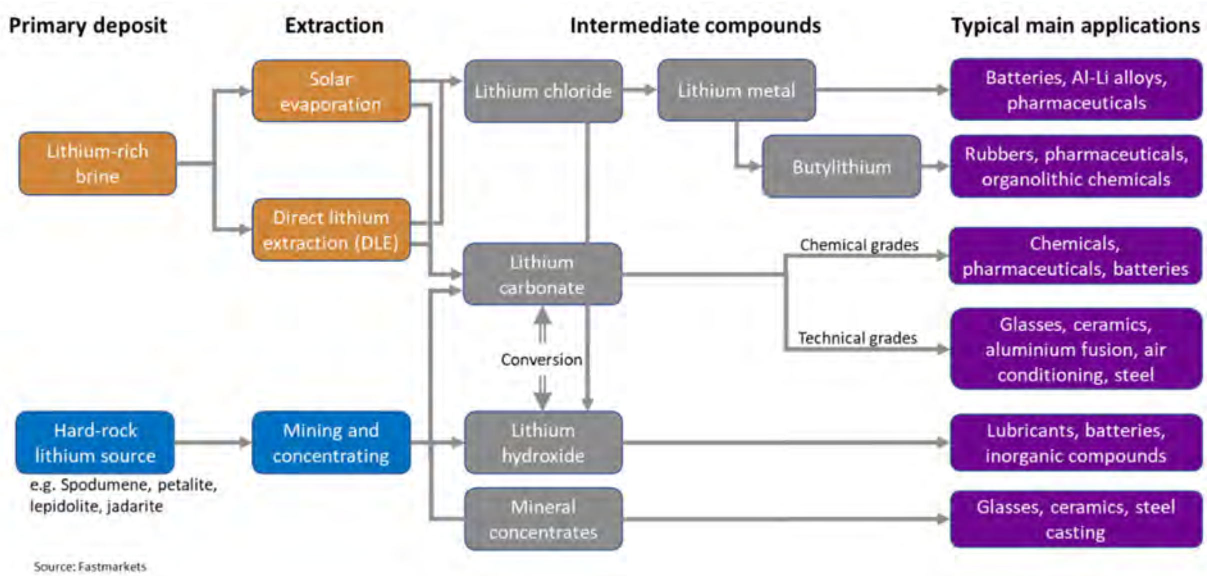


Figure prepared by Fastmarkets, 2024.

Electric vehicle demand, the largest single source of demand for lithium is disconnected from macroeconomic growth and is expected to remain robust primarily due to:

- Government policies and subsidies will continue to incentivize the purchase of electric vehicles over internal combustion engine vehicles;
- Smaller and more affordable electric vehicles, along with increasing gasoline prices, make electric vehicles price-competitive with internal combustion engine vehicles over normal ownership time-scales;
- Waiting lists for electric vehicles are extending current demand into the future;
- Standardization and increased access to charging networks will reduce range concerns with electric vehicles.

Changing global policies could affect macroeconomic factors supporting the lithium market and key among the policies are those related to the energy transition and energy storage, as well as electrification of transport (land, maritime and aviation). Examples of such policies enacted since 2021 include the US Inflation Reduction Act (IRA), the European Union Green Deal, the Canadian Critical Minerals Strategy and India's FAME II Strategy.

19.1.2 Demand

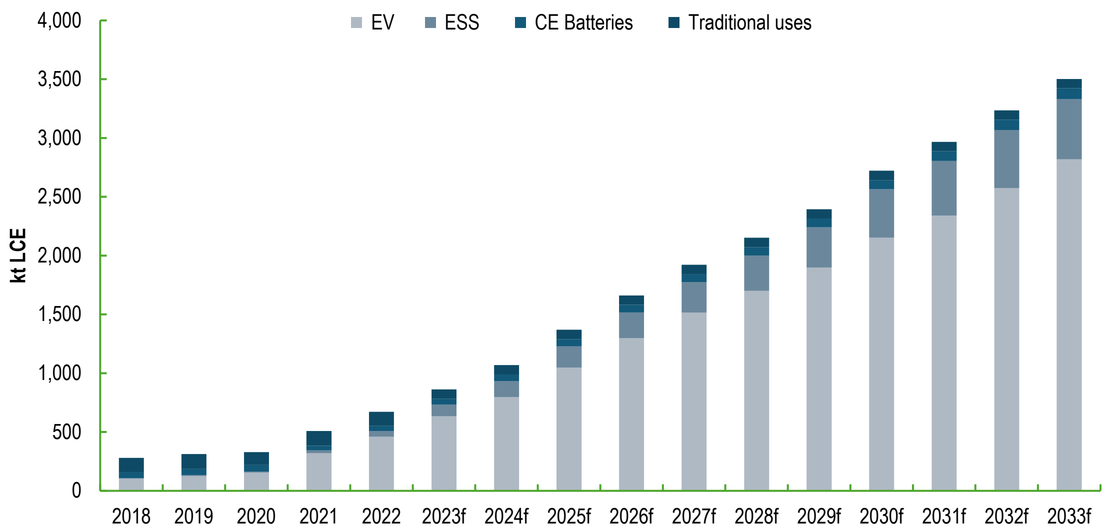
Global efforts to decarbonize transportation are driving a significant increase in electric vehicle adoption, especially in emerging markets such as Thailand, Brazil, and Malaysia, where electric vehicle sales surged in 2023. The decrease in battery and electric vehicle prices, particularly in China, is making electric vehicles more accessible to a broader range of consumers and in 2024, the market will see a substantial influx of new electric vehicle models, providing greater variety and choice for consumers. Simultaneously, residential and commercial energy storage systems are gaining popularity as both consumers and businesses aim to reduce their carbon footprints. Batteries are becoming increasingly vital for storing excess energy generated from renewable sources.

The demand for lithium has grown significantly over the past few years (Figure 19-2), driven primarily by the increased production of lithium-ion batteries used in electric vehicles. This trend is expected to continue, with future demand projections indicating a substantial rise in the need for lithium. Beyond electric vehicles, lithium-ion batteries are also becoming crucial for various applications, including energy storage systems, consumer electronics, power tools, and telecommunications, further driving demand.

The market for battery electric vehicles is expected to grow significantly in the coming years, with battery electric vehicles becoming a dominant segment of the automotive market by 2040 (Figure 19-3). Many regions are planning to phase out internal combustion engine vehicles, further boosting the demand for battery electric vehicles. Although plug-in hybrid electric vehicles will continue to be important, particularly in emerging markets, their growth is expected to slow as charging infrastructure improves, making fully electric vehicles more practical for a wider audience long term.

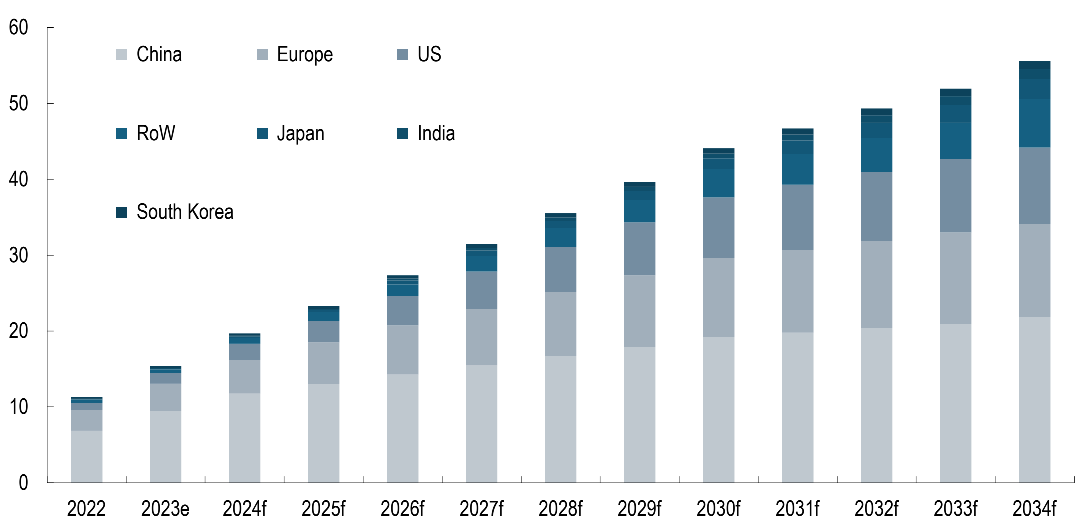
Overall, the anticipated growth in electric vehicles is expected to lead to a substantial increase in lithium demand, rising to 2.8 Mt lithium carbonate equivalent by 2033, reinforcing its critical role in the future of transportation and energy storage. The global demand for lithium is projected to double every few years throughout the current decade (Figure 19-4), highlighting the importance of continued innovation and investment in the lithium supply chain to meet this growing need. The e-mobility sector, in particular, is set to see robust growth, underscoring lithium's essential role in the transition to cleaner energy and transportation solutions.

Figure 19-2: Historic Demand and 10-year Forecast By End-Use



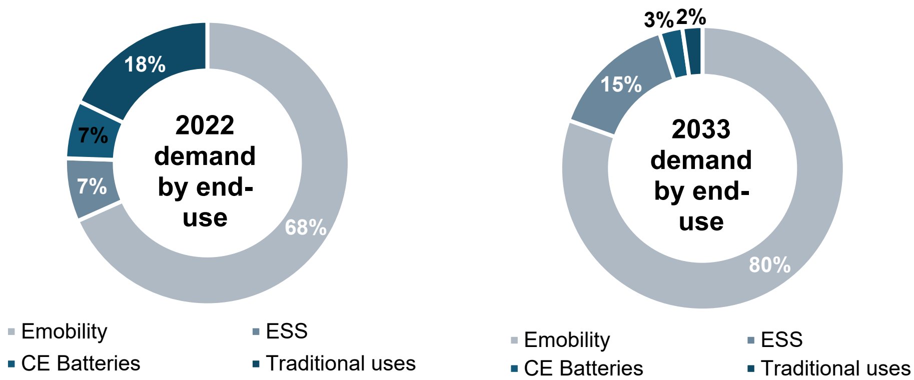
Note: Figure prepared by Fastmarkets, 2024. EV = electric vehicle; ESS = grid-scale energy storage; CE = consumer electronics; f = forecast.

Figure 19-3: Electric Vehicle Sales By Markets



Note: Figure prepared by Fastmarkets, 2024. Units shown on Y-axis in million units.

Figure 19-4: Demand by End-Use For Lithium In 2022 Versus 2033



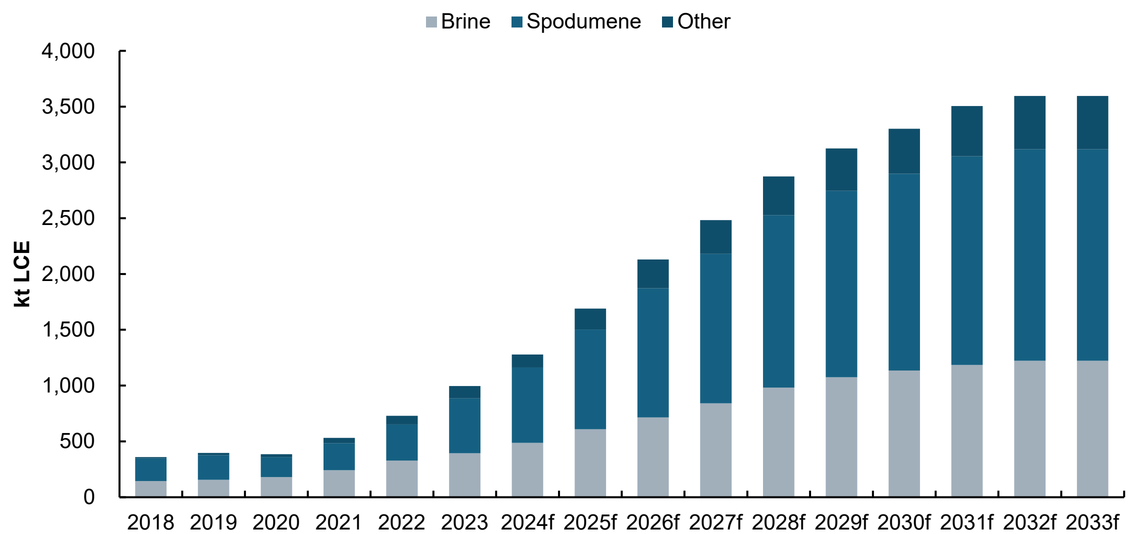
Note: Figure prepared by Fastmarkets, 2024. EV = electric vehicle; ESS = grid-scale energy storage; CE = consumer electronics. Emobility refers to all transportation by battery such as electric vehicles and bikes.

19.1.3 Supply

Lithium is primarily sourced from brine and hard-rock mineral deposits, with mineral concentrates being the largest source (Figure 19-5). Spodumene, a key lithium mineral due to its high lithium content, accounted for nearly half of global lithium production in 2022. Although the supply of lithium is expected to diversify, spodumene concentrates will continue to be a significant contributor to the overall supply, maintaining robust output. The current pricing environment is encouraging the development of lower-grade resources, particularly spodumene and lepidolite, the latter of which is expected to see significant growth over the next decade.

Global lithium mine supply is projected to reach a substantial level by 2033. However, increasingly stringent environmental, social, and governance requirements and lengthy regulatory processes in many jurisdictions are likely to extend the timelines for new lithium projects, adding long-term pressure on supply. While there are abundant lithium resources and numerous projects in the pipeline, the challenge lies in economically extracting these resources and bringing them online in a timely manner. Many projects are still in the early stages, and the difference between nameplate capacity and output should be noted as new and existing facilities will produce volumes below their nameplate capacity, resulting in limited visibility on supply sources beyond the next 5–10 years. Consequently, supply growth beyond 2033 is expected to be limited, despite some early-stage projects potentially coming online during this period.

Figure 19-5: Historic Mine Supply and 10-Year Forecast By Source



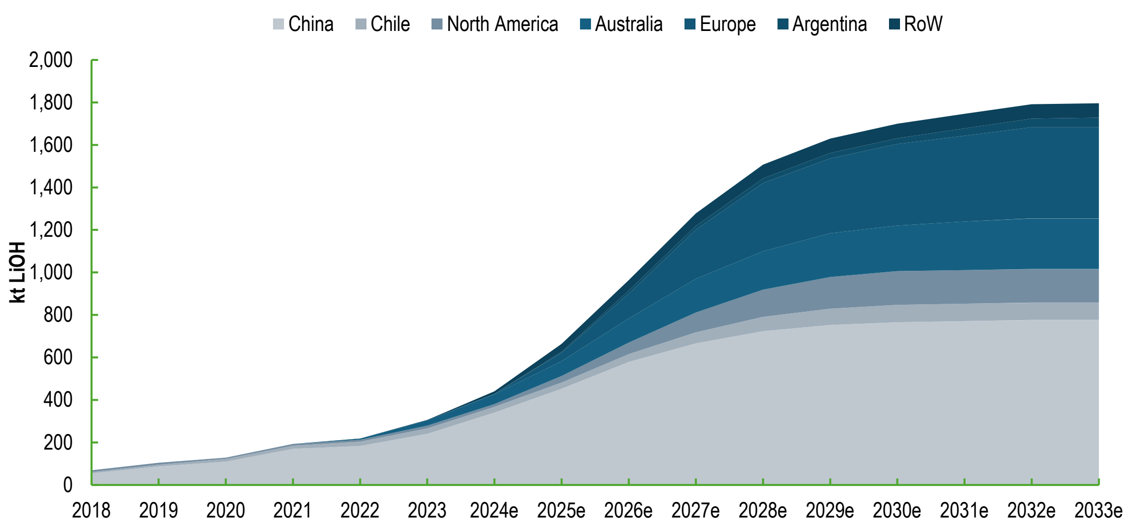
Note: Figure prepared by Fastmarkets, 2024.

The two main lithium products, lithium carbonate and lithium hydroxide monohydrate, are crucial for manufacturing the cathodes used in lithium-ion batteries. Lithium carbonate is widely used due to its stable chemical properties and straightforward production process. Lithium hydroxide monohydrate is increasingly preferred for high-nickel cathode chemistries due to its superior performance characteristics. As consumers, especially those outside China, seek higher energy densities and longer cycle lives, the demand for lithium hydroxide monohydrate is projected to grow significantly.

The production of battery-grade lithium hydroxide monohydrate has grown substantially since 2018, with China leading this growth. However, new mining operations in Australia, Argentina, Europe, and the US are now incorporating processing capacities to produce lithium salts, aiming to reduce reliance on Chinese sources and production of lithium hydroxide monohydrate outside of China is expected to rise significantly by 2033 (Figure 19-6).

The expanding electric vehicle market and evolving battery technologies will drive the critical need for efficient and timely lithium supply solutions to meet future demand.

Figure 19-6: Regional Breakdown Of Lithium Hydroxide Production



Note: Figure prepared by Fastmarkets, 2024.

19.1.4 Balance

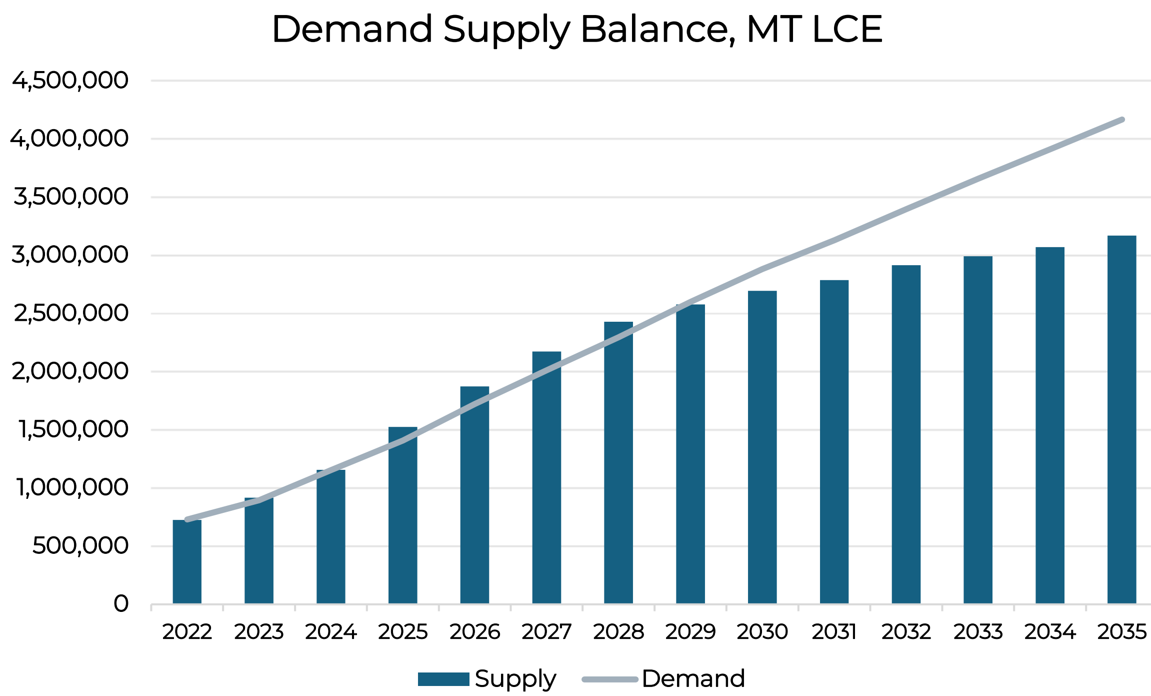
Supply additions from restarts, expansions, and greenfield projects that began in 2023, along with rapid supply increases in China, have shifted the market from a supply deficit to a surplus. Currently, new supply is still ramping up, while some high-cost production is being cut. As a result, there are no immediate concerns about supply shortages, though restocking could lead to short-term tightness.

A market undersupply is expected between 2028 and 2030, likely causing prices to rise to incentivize new production to fill these gaps (Figure 19-7). The current price environment's impact might be particularly significant later in the decade. The scaling back of capital investment now could lead to a stronger price environment in the first half of the 2030s.

19.2 Commodity Price Projections

A detailed future pricing study for lithium chemicals was developed for the Project using data from trusted research firms, covering battery-grade lithium carbonate and lithium hydroxide monohydrate prices for China, Japan, and Korea, as well as spodumene prices for China.

Figure 19-7: Lithium Supply/Demand Balance



Note: Figure prepared by Benchmark Markets Intelligence, 2024.

Current forecasts indicate that lithium prices will likely remain above the cost curve to incentivize supply expansion. However, prices at approximately US$70/kg (US$70,000/t) for lithium hydroxide monohydrate, as seen in 2022, are considered unsustainable. It is anticipated that prices will stabilize at levels beneficial for both producers and consumers. Volatility has been a feature of the market in recent years and is expected to continue, with potential periods of higher-than-expected prices during times of extreme tightness.

In the near term, prices for lithium hydroxide monohydrate and lithium carbonate are expected to remain depressed, averaging approximately $15 per kg ($15,000 per tonne) lithium hydroxide monohydrate in 2025 due to the forecast market deficit. Prices are expected to increase later in the decade to support the necessary pricing for incentivizing new greenfield projects.

The price forecast for lithium hydroxide monohydrate was based on yearly forecast from 2027 to 2034, where the long-term price used was the 2023 price of $31,000/t lithium hydroxide monohydrate, in Benchmark Mineral Intelligence's Q1 2024 report, published March 2024.

19.3 Contracts

It is anticipated that material contracts for the Project will include power, concentrating, refining, transportation, handling, and product offtake.

There are no material contracts in place as at the Report effective date. Any future contracts would be in line with similar contracts in Alberta.

19.4 QP Comments on Item 19

The QP reviewed the market analysis, marketing studies, commodity price projections, and they appear to be reasonable. The information can be used to support Brine Resource and Brine Reserve estimates and economic analyses.

20.0 ENVIRONMENTAL STUDIES, PERMITTING, AND SOCIAL OR COMMUNITY IMPACT

20.1 Introduction

E3 has not yet applied for the regulatory approvals required for the Project. Key components that will require permitting include: Central Processing Facility, well pads with mineral wells, and accompanying mineral scheme(s), and pipeline network required to transport brine to the Central Processing Facility for processing and refinement.

20.2 Central Processing Facility Permitting

Four key required regulatory application pathways have been identified for the overall permitting and approval of the Project. These pathways are as follows:

- Mineral Facility regulatory requirements;
- Well pads with mineral wells;
- Mineral scheme(s);
- Pipelines.

The regulatory applications and permitting requirements are summarized in Table 20-1. Approval of the Central Processing Facility will require the regulatory applications, assessments and guidance from various Alberta Energy Regulator Directives, as summarized in Table 20-2.

20.3 Environmental Studies

There have been two environmental studies completed to date on the potential proposed site for the Central Processing Facility, including a reconnaissance-level survey to identify potential environmental constraints and a Phase 1 environmental site assessment to identify potential environmental concerns. The potential site location has not been disclosed in this Report as the public consultation and notification processes to landowners and stakeholders is on-going.

A reconnaissance survey of the proposed site was conducted in November, 2023. The potential site is proposed on private land in Mountain View County. The Project area has historical and current oil and gas industrial activity There are no known environmental issues that could materially impact E3's ability to extract the Brine Resources or Brine Reserves.

Table 20-1: Approval Requirements for the Project

Regulatory Pathway	Permitting Requirements	Jurisdiction
Central Processing Facility	Directive 090 (D090) sets out the Alberta Energy Regulator's requirements for brine hosted mineral development	Provincial, Alberta Energy Regulator
	Environmental Protection and Enhancement Act application	Provincial, Alberta Energy Regulator
	Directive 056 (D056) for facility licences	Provincial, Alberta Energy Regulator
	Rezoning to "Mineral and Resource Extraction/Processing"	Municipal, Mountain View County
	Development permit	Municipal, Mountain View County
	Interconnection to the power grid (third-party)	Alberta Electric System Operator
	Substation for the third-party power cogeneration facility (third-party)	Alberta Utilities Commission
Scheme Applications	D090 Mineral Scheme application	Provincial, Alberta Energy Regulator
	Directive 065 (D065) for brine re-injection	Provincial, Alberta Energy Regulator
	Directive 065 (D065) for gas disposal	Provincial, Alberta Energy Regulator
Mineral Wells on Multi-well Pads	D056 for each mineral well	Provincial, Alberta Energy Regulator
	D051 for each injection/disposal well	Provincial, Alberta Energy Regulator
Pipelines	Conservation and Reclamation Plan for all Class 1 pipelines	Provincial, Alberta Energy Regulator
	D056 for pipeline licence(s)	Provincial, Alberta Energy Regulator

Table 20-2: Required Assessments

Area or Act	Note
Air quality assessment	To evaluate the air emissions from the Central Processing Facility, an air quality assessment will be done to meet the requirements of the Alberta Ambient Air Quality Objectives. The air quality assessment will be done in accordance with the Alberta Air Quality Model Guideline (AEP, 2021) and will evaluate of both maximum approved emission rates and typical emission rates. Non-routine (intermittent) flare emissions will also be evaluated to predict concentrations of H_2S and SO_2 from the emergency flare stack.
Historical Resources Act	A *Historical Resources Act* application to Alberta Arts, Culture & Status of Women will need to be conducted. Alberta Arts, Culture & Status of Women will review the *Historical Resources Act* application and issue either site approval with no further work requirements or conditions for additional work. The additional work typically consists of completion of a Historical Resources Impact Assessment for archaeological and/or palaeontological resources.
Water Act	Applications will be submitted to Alberta Environment and Protected Areas for any wetlands that will be impacted by the site. The Water Act applications will either be in the form of a Wetland Application Impact Form, which will be prepared to apply for approvals for minor wetland impacts or where impacts will not be permanent and can be mitigated using best practices and standard operating procedures for undertaking activities within a wetland.
Traffic impact assessment	A traffic impact assessment is required to support the approval of the Central Processing Facility. Confirmation of the key study requirements will occur in collaboration with Alberta Transportation and Economic Corridors and Mountain View County and identify any particular areas of concern.
Noise impact assessment	A noise impact assessment in compliance with Directive 038 (Noise Control) (D038) will need to be completed for the Central Processing Facility and electric energy generating equipment to understand the potential changes to the existing acoustic environment and impacts to residential dwellings and other receptors.
Fish Habitat assessment	All pipeline watercourse crossings in compliance with the Code of Practice for Pipeline and Telecommunication Lines Crossing a Water Body, the Code of Practice for Watercourse Crossings, the *Fisheries Act* and the Minor Works Order of the Canadian Navigable Waters Act, where applicable.

20.4 Water Management

20.4.1 Produced and Process Water

Produced brine and process water are described in Section 16 and Section 17, respectively.

20.4.2 Surface Water

No evaporative ponds or tailings ponds are required for the Project. A stormwater pond will be used to manage surface water run-off, with appropriate secondary containment and monitoring to ensure water quality standards are maintained. E3 does not require environmental surface water for use during normal operations.

20.4.3 Groundwater

A groundwater monitoring program will be implemented to monitor and detect potential impacts to fresh groundwater resources in the vicinity of the Central Processing Facility.

20.4.4 Domestic Water

The Central Processing Facility will require potable water during both the construction and operation phases for domestic, laboratory, hydrotesting, and safety needs.

20.5 Waste Management

20.5.1 Solid and Liquid Waste

The Central Processing Facility will produce calcium carbonate ($CaCO_3$) as a solid waste product that will be transported to a third-party licenced waste management facility. Solid waste associated with construction, maintenance, and turnaround activities will be disposed at third-party licenced waste management facilities. No liquid industrial waste will be produced from process operations.

20.5.2 Greenhouse Gases

The Project will require power that will lead to greenhouse gas emissions. As discussed in Section 18, approximately 165 MW is required for the combined Central Processing Facility and field production operations. A third-party natural gas-fired power cogeneration facility is planned to be constructed on the proposed Central Processing Facility location to supply this power. The third-party cogeneration facility will be the primary source of power, with a connection to the existing Alberta power grid as a back-up. Carbon dioxide capture and compression equipment at the cogeneration facility were included in the scope of the third-party power provider, and E3 plans to sequester the carbon dioxide on behalf of the third party supplier in the same manner and formations as the solution gas. As the reliability of the cogeneration facility is anticipated to be almost 100%, the emissions intensity is based on the third-party cogeneration facility emission intensity and not the Alberta power grid emission intensity. The carbon emission intensity from the Project would be an estimated 1.9 t CO_2e/tonnes lithium hydroxide monohydrate, based on approximately 615,000 t CO_2e/year from natural gas combustion and a sales output of 32,250 t lithium hydroxide monohydrate/year. The CO_2 capture technology will recover about 90% of the emissions from the third-party cogeneration facility.

20.6 Reclamation and Closure Plans

As required by Alberta's robust conservation and reclamation regulations, and through decades of industry expertise executing reclamation programs, the entire project will be reclaimed progressively as well pads, pipelines and other project infrastructure are decommissioned. Reclamation will be completed to ensure no harm to future land uses including agricultural use or other original land use capabilities such as wildlife habitat.

There will be two main reclamation plans, one each for the Central Processing Facility and one for the well pads and pipelines.

E3's conservation and reclamation plan for the project will contain measures for pollution prevention, and for mitigation of environmental impacts so to not impair future use of the environment. As such, the project will be planned, designed, constructed, and operated with final reclamation in mind, and with a view to progressively reclaiming parts of the site, whenever possible, throughout the life of the project.

20.6.1 Facility Reclamation and Closure Plan

The submission of a conceptual reclamation plan is required for the Central Processing Facility to fulfil the goals identified under the *Environmental Protection and Enhancement Act* related to pollution prevention, mitigating environment impacts, and not impairing future use of the environment. The reclamation plan will include:

- Descriptions of the end land-use and land capability, including how the reclaimed facility lands will blend into the surrounding landscape;
- Descriptions of proposed reclamation landforms, and how they will be integrated into adjacent land uses;
- Plans for replacing reclaimed soil that is compatible with the end land use;
- Plans for revegetation and descriptions of methods for measuring revegetation success;
- Plans for waste management during reclamation;
- Plans to manage dust, odour, air emissions, contaminants and noise;
- Environmental monitoring;
- Plan for stakeholder inputs into the final land use design and features.

20.6.2 Well Pads and Pipeline Reclamation

The objective of a Conservation and Reclamation Plan for the well pads and pipelines is to return the land to equivalent land capability, which requires that landscape, soil, biological resources and water be conserved and protected. The conservation and reclamation planning process for both well pads and pipelines will avoid:

- Native prairie, rare plants and their habitat;
- Sensitive landscape features such as coulees and river valleys that are sensitive to erosion;
- Wildlife habitat features;
- Historical resources, which are integral to Alberta's cultural heritage.

The Conservation and Reclamation Plan will be based upon detailed site surveys that may include including sensitive species inventories, soil, rare vascular plant, native grassland and aquatic ecosystem surveys.

The well pads will be reclaimed upon decommissioning using the detailed site inventories gathered during baseline surveys. The pipeline right of ways will be reclaimed following pipeline installation in a manner that avoids admixing of soil layers and reduces soil losses.

20.6.3 Reclamation Materials Storage

E3 will prepare a site-specific soil salvage and storage plan that will be based on detailed site soil surveys. This plan will be submitted with the *Environmental Protection and Enhancement Act* Application for the approval of the Central Processing Facility.

20.6.4 Reclamation and Closure Costs

E3 has estimated the total Project liabilities, including the costs of providing care and custody and the cost to permanently end operations which includes abandoning, remediating and reclaiming the site.

E3 will be required to pay facility abandonment and reclamation costs, an abandonment fee per well, and reclamation costs per well under Directive 011 (Licensee Liability Rating Program: Updated Industry Parameters and Liability Costs) (D011).

The facility abandonment cost and well reclamation costs (Table 20-3) used in the Licensee Liability Rating formula were based on the most recent cost assessment conducted by the Alberta Energy Regulator. The abandonment liability for a well must consider its geographic location based on the Regional Abandonment Cost Map, depth, downhole completion scenario, and where applicable, the number of events requiring abandonment, the costs to address groundwater protection, surface casing vent flows, and gas migration. E3 will be required to comply with the Liability Management Framework to prevent costs associated with the facility, well pads and pipeline being borne by the Alberta public.

The estimate is a high-level estimate of the costs to suspend, abandon, remediate, and reclaim the site, as well as provide care and custody from shutdown of operations through to site reclamation. Facility abandonment and reclamation costs were calculated based on the instruction in D006 for well equivalents for a facility designed to process 232,500 m^3/d, as detailed in Table 20-3.

20.7 Social and Community Requirements

20.7.1 Public Engagement

Table 20-4 summarizes E3's proposed public engagement initiatives.

20.7.2 Indigenous Engagement

The Project falls within Treaty 7 territory, comprised of the Siksika (Blackfoot), Piikani (Peigan), Kainai (Blood), Tsuut'ina (Sarcee), and Stoney-Nakoda First Nations, including Bearspaw First Nation, Chiniki First Nation and Wesley (Goodstoney) First Nation. The Project also takes place in Treaty 6 territory, comprised of Sunchild, O'Chiese, Montana, Samson Cree, Louis Bull and Ermineskin First Nations. The Aboriginal Consultation Office will determine on the level of consultation for the Project.

E3 will seek to engage with First Nations to understand and address their values, concerns and interests in the Project, and potentially explore options for economic development.

E3 intends to engage with Indigenous leaders within these communities on hiring of Indigenous businesses wherever possible. E3 is supportive of creating jobs either directly at the Clearwater facility or by promoting capacity building for Indigenous owned businesses that support the Clearwater facility (e.g., trucking company, and other support services). Building Indigenous capacity for the Project may take the form of a potential equity investment in the Project itself or by supporting of professional services, expertise and other support services required for the Project through entities such as the Alberta Indigenous Opportunities Corporation.

The Project is located on freehold-owned surface land, and therefore Crown consultation activities are not required.

Table 20-3: Abandonment and Reclamation Cost Estimate

<table>
<tr><th>Abandonment and Reclamation Tasks</th><th>Assumptions and Cost References</th></tr>
<tr><td colspan="2">Production and Injection Wells</td></tr>
<tr><td>Abandonment, including:
- Administrative and management cost;
- Removing all downhole equipment, such as rods and tubing
- Abandoning all completed formations;
- Testing for, reporting, and eliminating surface casing vent flow, gas migration, and other casing integrity issues;
- Removing surface equipment cement pads, and debris within 12 months of the cutting and capping operation, as required by Directive 020 (Well Abandonment);
- Maintaining vegetation control and good housekeeping;
- Disposing of any remaining drilling waste contained in on-site and remote sumps;
- Protecting groundwater;
- Managing hazards on site to protect public safety and the environment;
- Conducting the surface abandonment;
- Removal of power grid tie in.</td><td>Well abandonment liability assumes:
- $78,105 per well.
Cost references:
- Cost per well based on guidance in: Directive 011 Licensee Liability Rating (LLR) Program: Updated Industry Parameters and Liability Costs (Table 2, page 3, March 2015);
- Well abandonment and equipment removal guidance in: Directive 020: Well Abandonment (September 2023).</td></tr>
<tr><td rowspan="3">Reclamation, including:
- Phase I ESA;
- Phase II ESA;
- Maintaining the land and removing access roads and directly-related infrastructure;
- Removing gravel and other surface materials;
- Replacement subsoil and topsoil;
- Addressing any soil structure, hydrophobicity and similar issues;
- Recontouring and stabilizing slopes;
- Restoring surface drainage pattern;
- Planting, maintaining and monitoring vegetation;
- Preparing detailed site assessment;
- Completing reclamation certification process;
- Planting, maintaining and monitoring vegetation;
- Preparing detailed site assessment;
- Completing reclamation certification process.</td><td>Well pad reclamation liability (Parklands area) assumes:
- Based on Regional Reclamation Cost for Parklands Area;
- $27,250 per (first well), plus 10% ($2,725) for each additional well on the well pad ($38,150 per 5-well well pad x 38 pads).</td></tr>
<tr><td>Phase I ESA on each of 38 well pads at $5,000 per ESA</td></tr>
<tr><td>Phase II ESA on 20% of well pads at $25,000 per ESA.
No remedial work will be required on well pads.
Cost References:
- Cost per well based on guidance in: Directive 011 Licensee Liability Rating (LLR) Program: Updated Industry Parameters and Liability Costs (Section 8, page 4, March 2015);
- Environmental Sie Assessments (ESAs), Phases I and II based on professional judgement of similar like projects.</td></tr>
</table>

Abandonment and Reclamation Tasks	**Assumptions and Cost References**
Pipelines	
Abandonment, including: - Reviewing files and locating the line; - Removing aboveground structures; - Physically isolating or disconnecting the pipeline; - Cleaning, if necessary; - Purging with fresh water, air, or inert gas; - Addressing residual contamination from spills; - Plugging or capping all open ends; - Intermediate cutting and blocking; - Removing underground pipelines, where required; - Managing hazards on site to protect public safety and the environment.	Pipeline abandonment estimate assumes: - Pipeline will be abandoned in place and not associated with pipeline facilities located outside of well pads or Central Processing Facility; - Length of the pipeline associated with one well pad is 1.5 km; - $20,000 per km of pipeline. Cost references: - Cost of abandonment work per km of pipeline based on professional judgement of similar projects.
Reclamation, including: - Phase I ESA; - Maintaining the land and removing access roads and directly related infrastructure; - Removing gravel and other surface materials; - Replacement subsoil and topsoil; - Addressing any soil structure, hydrophobicity and similar issues; - Recontouring and stabilizing slopes; - Restoring surface drainage pattern; - Planting, maintaining and monitoring vegetation; - Preparing detailed site assessment; - Completing reclamation certification process.	Pipeline reclamation estimate assumes: - One Phase I ESA for full pipeline network at $20,000 per ESA; majority of estimate covered under wells; - No Phase II ESA or remedial work will be required on pipeline right-of-way; - Pipelines abandoned in place, and all reclamation work completed at time of pipeline construction. Cost reference: - Cost of abandonment work per km of pipeline based on professional judgement of similar projects.
Central Processing Facility	
Abandonment: - Identifying and managing dangerous materials and radioactive materials; - Shutting down, draining, and purging all lines, vessels, and ponds; - Testing pond liquids and sludge; - Removing and transporting products, dangerous goods, and oilfield waste for off-site management; - Dismantling and removing all equipment, vessels, structures, and utilities;	Facility abandonment assumes: - Facility estimate based on removal of buildings, storage tanks, roads, and all associated infrastructure (e.g., cathodic protection removal); - Abandonment liability estimated includes three sour gas wells at $17,000 per well equivalent; - Does not include removal of third party substation supplying power to the facility. Cost reference: - Cost of abandonment work per sour gas well based on professional judgement of similar projects.

Abandonment and Reclamation Tasks	Assumptions and Cost References
- Removing and disposing of pads, berms, ponds, foundations, piles, concrete, and other base and surfacing materials; - Abandoning or removing pipe; - Managing hazards on site to protect public safety and the environment; - Removing utilidors and cathode beds; - Removal of sour gas disposal wells.	
Reclamation, including: - Phase I ESA; - Phase II ESA; - Maintaining the land and removing access roads and directly-related infrastructure; - Removing gravel and other surface materials; - Replacement subsoil and topsoil; - Addressing any soil structure, hydrophobicity and similar issues; - Recontouring and stabilizing slopes; - Restoring surface drainage pattern; - Planting, maintaining and monitoring vegetation; - Preparing detailed site assessment; - Completing reclamation certification process.	Facility reclamation assumes: - Facility reclamation was estimated based on competitive tender basis at $1.1 million; - Transporting dangerous good, and off-site management costs = $1 million; - One Phase I ESA for facility at $30,000 per ESA; - Cost of Phase II ESA or remediation is not included, and should be estimated at a later date. Cost reference: - ESAs, Phases I and II based on professional judgement of similar projects.

Note: ESA = environmental site assessment.

Table 20-4: Proposed Public Engagement Initiatives

Directive, Act, or Area	Considerations	Planned Initiatives
Directive D056	Process stipulated for licence approvals for each Project component (i.e., facility, wells and pipeline). E3 will need to consider timing constraints into the Public Involvement Plan process such as planting, harvesting or calving times. Residents and other stakeholders within these prescribed zones must be notified of the applications for each relevant Project component in advance of filing the D056 application and includes distributing E3's information package in accordance with D056 specifications. E3 is required to track and submit a record of consultation and notification for the Project to the Alberta Energy Regulator for the D056 applications.	E3 will develop a participant involvement list for the Central Processing Facility, brine production and injection wells, and pipelines according to guidance set out in Table 1-5 of D056. Notification radii will also incorporate Emergency Planning Zones. E3 must address resident and other stakeholder questions, objections and concerns regarding the Project and individual components and attempt to resolve them.
Responsible Energy Development Act	Consultation and notification program under *The Responsible Energy Development Act* will take place immediately following the filing of the *Environmental Protection and Enhancement Act* Application with the Alberta Energy Regulator. Once the public notice of application is provided in accordance with the R*esponsible Energy Development Act*, any person who believes that they may be directly and adversely affected by the application typically has 30 days to file a statement of concern with the Alberta Energy Regulator.	Broader mandated public participation and exists under the provisions of the *Responsible Energy Development Act*. This potentially represents significant and multiple opportunities for public participation/objection of the Clearwater Project.
Broader consultation process	For most Albertans, E3 is a relatively unknown company, and the technology proposed for Clearwater is unique. It will be important for E3 to build and own the narrative around this development. The operation of the direct lithium extraction pilot facility during fall 2023 made E3 more known in the general community. E3 has conducted several site tours of the pilot area, including hosting the Alberta Energy Regulator on September 19, 2023.	Throughout the broader engagement process E3 will describe the direct lithium extraction technology, the low impact of lithium extraction and benefits and risks. Educational type materials may include: - Information brochures; - Frequently-asked questions, website content; - Social media campaigns, and site tours, will be used to promote the industry, describe E3's technology, and the low impact type of lithium extraction, benefits and risks.

21.0 CAPITAL AND OPERATING COSTS

21.1 Introduction

The capital cost estimate for the 2024 PFS was completed by breaking the facilities down into a work breakdown structure and estimating each section using industry standard estimating practices for an AACE International Class 4 estimate (-30% to +50%). The capital cost estimate includes engineering, materials, equipment, and labour required to design, build, and construct a commercial lithium extraction well network, gathering system and Central Processing Facility and produce lithium hydroxide monohydrate over a 50-year production life.

The capital cost estimate was completed by an experienced cost estimator who determined its accuracy as Class 4 by assessing the extent and maturity of the estimate input information (e.g. vendor-supplied data, key planning and design deliverables).

The operating cost estimate was compiled using data from vendors, calculated from engineering design, and from allowances where operating cost data from vendors were not available.

21.2 Basis of Capital Cost Estimate

The capital cost estimate was developed using budgetary vendor quotes, historical pricing, and industry accepted allowances. Budgetary vendor quotes were used for all major equipment, while minor equipment was estimated using either historical data or budgetary vendor quotes. Where allowances have been used, the allowance has been identified in the report for clarity. Factors were used to determine installed equipment cost.

The capital cost estimate includes both direct and indirect field costs. The sum of the direct field cost and the indirect field cost is the total field cost. The direct field cost includes factored equipment cost, materials which have been adjusted for winterization, labour which has been adjusted for productivity expected in central Alberta, utilities and offsites, and freight calculated as 8% of equipment and material cost. Installation factors were selected for the equipment based on the equipment type and the level of modularization expected from the vendor. Labour rates were based on current rates for southern Alberta and it is expected that offsite fabrication and module assembly will be the preferred execution strategy. The indirect field cost was calculated as a percentage of the direct field cost and includes contractor indirect costs such as contractor management and supervision, temporary construction facilities, temporary construction services, construction equipment, small tools and consumables, and contractor overhead and profit. Engineering is included as a percentage of the total field cost.

All costs for the project were estimated and calculated in Canadian dollars and converted to United States dollars. All costs outlined in this Report are in 2024 US$ with an exchange rate of CA$:US$ of 1.34.

21.2.1 Brine Production and Brine Injection Wells and Well Pads

Field development will use multi-well pads, an approach which supports E3's commitment to minimizing environmental impact by minimizing the number of pads.

The drilling cost per well was determined by the hole size to fit the appropriately sized casing and the total time taken to go from commencement to rig release. The drilling cost included all related equipment and services that are part of the drilling process, such as logging, cementing, mud system, and casing. This cost included a portion of the pre-drill activities such as survey and construction of the pad, and rig mobilization/demobilization costs. This cost was the same between production and injection wells.

The completion cost per well was determined by the equipment and services required to complete the well, and varies between producers and injectors. For production wells, the completion cost consisted of the cost to install the electric submersible pump, run the tubing, and install the wellhead, tie-in to the pipeline, and install surface equipment necessary for the electric submersible pump and instrumentation. For injection wells, the completion costs consisted of the tie-in to the pipeline system, and instrumentation installation. The surface pumps for the reinjection brine will be in the Central Processing Facility and their costs were included there. Due to significant differences in costs for larger casing required to enable lower well counts, the overall project capital was minimized by selecting a lower rate well and pump design.

Vendor quotes were obtained for the capital estimate for the wells and pads, and includes:

- Pre-drill: road and lease preparation and maintenance; permits, taxes, and well licencing costs; land services;
- Drilling and completion operations: rig costs (rig move in/out, daily rig costs, and required rig equipment rental); daywork; crew subsistence and travel; fuel, water, power, and boiler; trucking; disposal; logging and wireline services; communications, safety, and security;
- Materials: drill bits; conductor; casing; cement; drilling fluids and additives; wellhead and wellhead equipment; tubing; artificial lift and variable frequency driver; packers.

The key assumptions for the well cost estimate are:

- Drilling: 7 days/well;
- Completion: 4 days/well;

- Pad Type "A": 4 producer wells + 1 injector well;
- Pad Type "B": 1 producer well + 4 injector wells.

Wells will be batch drilled on pads, which increases drilling efficiency. This approach will enable continuous operation of the drilling and completion rigs, minimizes mobilization and demobilization costs, and streamlines overhead related to auxiliary equipment and services.

21.2.2 Brine Production and Injection Pipelines

Vendor quotes were received for brine production and injection pipelines, including installation. The quotes cover earthworks, structural supports, instrumentation and controls, electrical building and infrastructure costs, and materials. Materials include surfacing and buried piping, surface pipe fittings, valves, and pipeline crossings. Allowances were used for pipeline fittings, pipeline right of ways, and emergency shutdown valves within the pipeline system for the safe operation of the pipelines. A fiber optic leak detection that will be run parallel to the brine production and brine injection pipelines in the pipeline trench is also included in the cost estimate.

The pipeline cost estimate is based on 198 km of production and injection pipelines. The final location of the well pads and pipeline routing may change through the feasibility stage and/or during the standard Alberta consultation and permitting process. Pipeline crossings will be minimized and will be further optimized during a planned Feasibility Study. The pipeline cost estimate includes the construction of a natural gas pipeline for delivery of natural gas to the proposed Central Processing Facility location to support third-party power generation.

21.2.3 Brine Treatment and Gas Handling

Vendor quotes were received for brine treatment and gas handling equipment. The equipment includes three-phase separators, tanks, vapour recovery units, compression, water recovery brine evaporators, sour water treatment, brine reinjection pumps, gas disposal wells, and am emergency flare. A factor was used to develop the total installed cost and was selected based on modularization of packages complete with building, as applicable.

21.2.4 Lithium Extraction, Purification and Carbonation

Vendor quotes were received for the lithium extraction, purification and carbonation equipment. A factor was used to develop the total installed cost. The factor selected was based on some modularization of equipment. The vendor will provide the initial membranes and the resins required for the process and the costs are included in the lithium extraction equipment costs. The initial sorbent volume required for start up of the equipment is included in the first fills.

21.2.5 Lithium Hydroxide and Packaging

Vendor quotes were obtained for the major equipment to convert lithium carbonate to battery-grade lithium hydroxide monohydrate. Historical data were used to estimate the auxiliary equipment such as the small pumps, conveyors, and cranes that support the major equipment. A factor on all equipment was used to develop the total installed cost.

The final battery-grade lithium hydroxide monohydrate product will be packaged into large totes in a carbon dioxide free air environment. A packaging vendor worked with E3 to define the scope and provide costs.. An installation factor was applied to the vendor quote.

21.2.6 Chemical Handling

The estimate for chemical handling from the truck offloading point into storage and from storage to the process is prepared on an equipment-factored basis and a vendor quote.

21.2.7 Site Preparation

The capital cost estimate for site preparation includes allowances for earthworks for the Central Processing Facility to prepare the site for construction, the cost of the Central Processing Facility land purchase, and road upgrades for a road in close proximity to the Central Processing Facility.

21.2.8 Buildings

Equipment will be located in buildings where possible to minimize noise, maintain process temperature, and provide a safe working environment for the operators on site. Non-process buildings such as warehouses, laboratories, offices, security and a health and safety building were also included as an allowance in the capital cost estimate.

21.2.9 First Fills

The capital for the first fills includes the initial chemicals, resin for the lithium carbonation step, and the sorbent for direct lithium extraction, which will all be required to start up the plant. The first fill of water for process, fire and potable water is also included.

21.2.10 Contingency

Contingency is applied to allow for the effect of unknowns on the cost estimate that experience shows may result in additional cost. Contingency of 20% was used for all of the surface facility equipment including the Central Processing Facility. Contingency was applied as 10% to the cost of wells, well pads and pipelines. Contingency excludes major scope changes, extraordinary events, escalation, and currency effects.

21.2.11 Capital Expenditures Summary

The total capital cost for the project is summarized in Table 21-1.

21.2.12 Sustaining Capital

Equipment at the well pads and at the Central Processing Facility requires capital investment at regular intervals to operate reliably. The sustaining capital costs and the frequency of capital investment for the first 25 years of operating life of the plant and field are summarized in Table 21-2. When the facility sustaining capital is calculated on an annual basis, the cost is approximately US$26 million per year. Sustaining capital is assumed from the second year of operation, and the cashflow analysis assumes that no sustaining capital is required in the first year of operation.

Beyond 25 years, sustaining capital was increased to account for maintenance of the older facility. The increased sustaining capital was calculated by dividing the initial equipment capital cost, as invested in Year 1, by 25 and spreading it across Years 26–50 of production life. This increased sustaining capital is intended to cover the cost of replacing Central Processing Facility equipment between Year 26 and the final year of production operation (Table 21-3).

Major maintenance capital costs were included for the facility at approximately US$10 million per year when calculated on an annual basis.

21.2.13 Abandonment, Decommissioning and Reclamation Costs

A cost allocation of US$27.4 million was included at the end of the production life to cover abandonment, decommissioning and reclamation of the production and injection wells, the pipelines, and the Central Processing Facility.

21.2.14 Exclusions

Cost for commissioning, capital spares (i.e. items that are not required for normal maintenance), escalation, and duties are excluded. The capital cost estimate does not include a camp for personnel as E3 plans to hire locally, as there is an experienced workforce available.

Table 21-1: Capital Cost Estimate Summary

Area	Installed Cost (US$ x 1,000)
Brine production and brine injection wells	378,496
Brine production and injection pipelines	448,134
Brine treatment	448,146
Lithium extraction, purification and carbonation	403,971
Lithium hydroxide, crystallization and packaging	255,144
Chemical handling	52,741
Site preparation (allowance)	31,095
Buildings (allowance)	49,751
First fills	55,970
Contingency	342,028
Total	***2,465,476***

Table 21-2: Sustaining Capital for Year 1 to 25 of Operation

Maintenance Activity	Total Sustaining Capital (US$ x 1,000)	Replacement Included
Well sustaining capital	6,911	One-time well workover for production optimization
Central processing facility maintenance	368,844	Membrane, resin and sorbent replacement
Major maintenance	282,022	Sour gas compressor overhauls, electric submersible pump replacement
Total sustaining capital	657,777	
Average annual sustaining capital over 25 years	***26,311***	

Table 21-3: Sustaining Capital for Year 26 to Year 50 of Operation

Maintenance Activity	Replacement Cost (US$ x 1,000)	Replacement Included
Base Central Processing Facility maintenance	384,213	Membrane, resin and sorbent replacement
Additional Central Processing Facility maintenance	503,731	Additional maintenance for operation of older facility
Major maintenance	225,618	Sour gas compressor overhauls, electric submersible pump replacement
Total sustaining capital	1,113,562	
Average annual sustaining capital over 25 years	***44,542***	

21.3 Operating Cost Estimate

The annual operating cost was calculated using quantity and pricing information provided through vendor quotes or by engineering calculation. An allowance was assumed for some miscellaneous costs.

The operating costs are average annual costs over the 50-year operating life of the project and are reported in US$/year.

21.3.1 Basis of Estimate

The operating expenditure presented in this sub-section is based on an average production rate of 25,850 t/a of battery-grade lithium hydroxide monohydrate and a nameplate facility capacity of 32,250 t/a with a 92% uptime over the project production life of 50 years.

21.3.2 Well Cost

The operating cost estimate for the wells includes both fixed and variable costs (Table 21-4).

Fixed costs include ongoing operating expenses related to production and injection wells such as well workovers, well pad lease and costs for berm maintenance, and minor earthworks.

Variable costs depend on production rates and includes corrosion inhibitor for the production wells. Power for the wellpads is a variable cost (see Section 21.3.6).

Table 21-4: Average Annual Fixed and Variable Well Cost

Description	Average Annual Cost (US$/year x 1,000)
Well fixed costs	$3,640
Well variable costs	$1,749
Total average annual cost for wells	***$5,389***

Fleet vehicle costs for well inspections were excluded.

21.3.3 Maintenance

Planned maintenance activities are necessary to ensure the efficient operation of the well pad facilities, pipelines, and the Central Processing Facility. The maintenance costs were estimated using a percentage of equipment cost. A 3% allocation for equipment capital was used for the pipeline maintenance estimate, and a 4% factor was used to estimate the wellpad and Central Processing Facility maintenance costs.

21.3.4 Pipeline Leak Detection

An experienced, local vendor provided a quote for a fiber optic monitoring system to ensure the safe and reliable operation of the pipeline network. The monitoring system is intended for preventative monitoring and event detection. The capital cost for the system is included in the capital cost estimate, and a monthly fee for the term of the agreement is included in the operating cost estimate.

21.3.5 Chemicals and Trucking

The lithium hydroxide monohydrate production process requires the use of various chemicals including quicklime, hydrochloric acid, caustic and soda ash. The initial chemical quantities were based on preliminary process information from an engineering contractor and from vendors who recommended quantities for the process. The quantities of chemicals consumed were changed over time with lithium hydroxide monohydrate production in the economic assessment.

Chemical costs were based on pricing received from local suppliers. For the purposes of the 2024 PFS, chemicals will be trucked to the site from an existing transload facility in the area.

21.3.6 Power and Natural Gas

Electrical power will be provided to the well pads and the Central Processing Facility through a third-party cogeneration facility anticipated to be co-located with the Central Processing Facility. The pipeline network will not require booster pumps so there will not be any electrical consumption from the pipeline system. Grid tie-in will be provided for redundancy and to enable the possibility for return of excess power back to the grid in the future. The heat from the turbines at the cogeneration facility will be captured and used to generate steam for the Central Processing Facility. The total power required for the Central Processing Facility and field commercial operation is estimated at 165 MW.

The electrical operating cost includes power supply to the Central Processing Facility and well pads, and storage of emissions from the turbines. The estimated power costs for the well pads and Central Processing Facility are shown in Table 21-5.

21.3.7 Waste Disposal

All liquid waste streams from the process will be combined with the reinjection brine and injected back into the Leduc Reservoir. The major source of solid waste from the Central Processing Facility process will be the calcium carbonate stream and the volume of the solid waste was estimated by the vendor. The estimated disposal cost is shown in Table 21-6. Waste will be trucked to a local disposal facility.

21.3.8 Operations Personnel

A total of 200 full time equivalent positions are included in the personnel for the commercial facility. The facility is expected to be a 24-hour operation. The Central Processing Facility and field facilities will be near large cities and towns with a highly skilled labour pool and personnel are expected to be hired locally. The personnel for the commercial operation are summarized in Table 21-7.

21.3.9 Miscellaneous Cost

An annual allowance of US$5.4 million was included to cover miscellaneous costs such as Central Processing Facility site maintenance, environmental monitoring and insurance.

21.3.10 Operating Cost Summary

The average annual operating expenditure for the field and the Central Processing Facility is summarized in Table 21-8.

21.3.11 Exclusions

The operating cost estimate does not include a camp or travel expenses for personnel.

Table 21-5: Table 5: Average Annual Cost of Power

Description	**Average Annual Cost (US$/year x 1,000)**
Well pad power	38,522
Central Processing Facility power	41,145
Total average annual cost of power	***79,667***

Table 21-6: Table 6: Average Annual Cost of Waste

Description	**Average Annual Cost (US$/year x 1,000)**
Liquid waste	—
Solid waste	2,484
Total average annual cost of waste	***2,484***

Table 21-7: Summary of Operations Personnel

Position	**Total Full-Time Equivalent**	**Shift**
HR and admin	3	Day
Security and safety	24	Day and night
Operations	92	Day and night
Management	6	Day
Technical staff	11	Day
Maintenance	36	Day and night
Site services	20	Day and night
Laboratory and QA/QC	8	Day and night
Total full-time equivalent	***200***	

Table 21-8: Operating Cost Summary

Description	**Average Annual Operating Cost (US$/year x 1,000)**
Well fixed costs	3,640
Well variable costs	1,749
Maintenance	26,491
Pipeline leak detection	109
Chemicals and trucking	48,512
Power and natural gas	79,667
Waste disposal	2,484
Operations personnel	19,372
Miscellaneous cost	5,380
Total Average Annual Operating Cost	***187,404***

22.0 ECONOMIC ANALYSIS

22.1 Forward-Looking Information Note

Please refer to the note at the front of this Report for information on forward-looking information.

22.2 Introduction

The economic analysis combines the production profile from the Leduc reservoir provided by the production well network and the estimated capital and operating costs to extract, pipe and process the brine and further refine it into a saleable lithium hydroxide monohydrate product.

The economic analysis was prepared using a discounted cash flow economic model, showing both pre-tax and post-tax results. The model includes government royalties and taxes and there are no commercial royalties/payments expected. Any Freehold lands within the Project are assumed to have a royalty rate that is equivalent to government royalties. The results include net present value (NPV) for an 8% discount rate, internal rate of return (IRR), and a sensitivity analysis of key inputs.

22.3 Model Basis

The basis of the discounted cash flow model includes:

- Discount rate of 8% per year used to discount all future cashflows;
- Assumed start of production in 2027 with Year 1 of the model being the start of capital expenditure;
- Unlevered basis, which assumes that the project is financed from E3's equity and does not account for any interest expenses (debt) or interest income (cash);
- Real basis, which means that all future cash flows are accounted for in 2024 dollars with no provision for inflation or escalation of costs or revenue;
  - Applicable taxes and royalties have been accounted for;
  - A third-party research firm price forecast was used for the duration of the project with an average selling price of US$31,344/t over the producing life (weighted for production);
  - Base case technical and economic outputs ;

- All amounts estimated in Canadian dollars (CA$) were converted to United States dollars (US$) at an exchange rate of 1.34 (CA$:US$) unless otherwise specified.

The Central Processing Facility will produce lithium hydroxide monohydrate, and all estimates for the production quantities and price forecasts use lithium hydroxide monohydrate, with the Brine Reserves reported in both lithium carbonate equivalent and lithium hydroxide monohydrate.

22.4 Inputs and Assumptions

The economic analysis is based on the recovery assumptions in Section 13, the Brine Reserves in Section 15, the mine plan outlined in Section 16, the process plan in Section 17, the infrastructure requirements in Section 18, the marketing plan and commodity pricing set out in Section 19, the assumptions as to environmental, permitting and social considerations in Section 20, and the capital and operating costs in Section 21.

The key inputs and assumptions are listed in Table 22-1. These assumptions represent the base case for the commercial operation.

No escalation or inflation was applied to the economic analysis.

A straight line depreciation over the 25-year design life was used for this analysis.

22.5 Taxes, Royalties and Other Government Levies or Interests

22.5.1 Royalties

The following royalties were applied :

- Alberta crown royalties for metallic and industrial minerals are set at 1% gross mine revenue before payout, and the greater of either 1% gross mine-mouth revenue or 12% net revenue after payout;
- Payout is defined as the date that the total project costs are equivalent to total revenues on the project, or four years after production start for the 2024 PFS;

The total project royalty payments are estimated at approximately US$3.3 billion over the expected 50-year production life.

Table 22-1: Project Economic Model Key Input Parameters

Key Parameters	Units	Value
Brine production	m^3/d	232,500
Plant availability	%	92.0
Lithium recovery	%	90.4
Initial annual production of lithium hydroxide monohydrate	t/a[1]	32,250
Average annual production of lithium hydroxide monohydrate of life of project[2]	t/a	25,850[3]
Production life	years	50
Total initial capital cost estimate	US$	2,465,476,000
Total sustaining capital cost estimate	US$	1,263,699[4]
Major maintenance capital cost estimate	US$	507,640,000[4]
Total abandonment capital cost estimate	US$	27,404,000[4,6]
Average annual operating cost	US$/year	187,403,000[3]
Average annual sustaining and major maintenance capital (Years 1–25)	US$/year	26,311,000
Average annual sustaining and major maintenance capital (Years 26–50)	US$/year	44,542,000
Weighted average selling price	US$/t	31,344[3,5]
Discount rate	%	8
Foreign exchange rate	C$/US$	1.34
Federal tax rate	%	15
Provincial tax	%	8
Clean energy investment tax credit	%	0

Notes:

1. Tonnes (1,000 kg) per annum.
2. Facility operating life is 25 years while Brine Reserves support a 50-year production life.
3. Average over 50-year production life.
4. Total over 50-year production life.
5. Based on the price forecast outlined in Section 19.
6. Abandonment, decommissioning and reclamation for producer and injection wells and Central Processing Facility.
7. Numbers have been rounded.

22.5.2 Taxes and Tax Credits

A blended Federal and Provincial income tax rate of 23% was used to calculate the projected income taxes payable.

To calculate after-tax income for the project, deductions with respect to capital expenditures incurred were used, including the use of Canadian development expense, capital cost allowances and non-capital loss carry forward tax credits.

The cash flow model does not include any allowances for government funding for critical minerals including the Canadian Federal Government Clean Technologies Tax Credit (ITC) draft legislation from 2023.

22.6 Cashflow Analysis

Annual cash flow forecasts including revenue, operating expenses and production for the base case are shown in Table 22-2.

A summary of the key base case economic outputs from the economic analysis are presented in Table 22-3. The post-tax NPV is $3.72 billion, the post-tax IRR is 24.6%, and the payback period is four years.

22.7 Sensitivity Analysis

A sensitivity analysis was carried out by varying single parameters while keeping others unchanged to isolate their impact on the projected NPV8% and IRR. The analysis was completed under after-tax conditions. The sensitivity analysis was conducted for each of the key project parameters:

- Initial capital cost estimate, major maintenance and abandonment (±20%);
- Operating expense and sustaining capital (±20%);
- Selling price (±20%).

Table 22-2: Annual Cash Flow Model

Year	LHM Production (Mt)	LHM Price (US$/t)	Total Revenue ($ x 1,000)	Royalties ($ x 1,000)	Total Operating Costs[1] ($ x 1,000)	Initial Capital Cost ($ x 1,000)	Major Maintenance Capital Cost [2] ($ x 1,000)	Abandonment Capital Cost ($ x 1,000)	Before Tax Cash Flow ($ x 1,000)	Income Tax ($ x 1,000)	After Tax Cash Flow ($ x 1,000)
2026	—	—	—	—	—	2,465,476	—	—	(2,465,476)	—	(2,465,476)
2027	32,163	21,500	691,495	6,915	199,489	—	—	—	485,092	3,731	481,360
2028	32,250	25,000	806,247	8,062	215,408	—	14,101	—	568,675	3,143	565,532
2029	32,220	36,500	1,176,016	11,760	215,349	—	14,101	—	934,806	156,314	778,492
2030	32,115	41,000	1,316,701	102,485	215,141	—	14,101	—	984,973	210,357	774,616
2031	31,919	39,500	1,260,794	125,596	214,755	—	14,101	—	906,341	205,594	700,747
2032	31,643	35,500	1,123,322	108,337	221,122	—	—	—	793,863	171,797	622,066
2033	31,273	32,000	1,000,731	94,545	213,481	—	14,101	—	678,604	155,910	522,694
2034	30,870	31,000	956,974	89,391	212,686	—	14,101	—	640,796	149,547	491,249
2035	30,562	31,000	947,429	88,320	212,079	—	14,101	—	632,929	148,476	484,453
2036	30,318	31,000	939,863	87,471	211,597	—	14,101	—	626,694	147,275	479,419
2037	30,110	31,000	933,411	86,748	211,187	—	—	—	635,476	137,257	498,219
2038	29,907	31,000	927,113	86,042	210,786	—	14,101	—	616,184	142,149	474,036
2039	29,690	31,000	920,405	85,290	210,359	—	14,101	—	610,655	142,803	467,852
2040	29,454	31,000	913,066	84,467	209,892	—	14,101	—	604,606	142,021	462,586
2041	29,198	31,000	905,146	83,579	209,388	—	14,101	—	598,078	140,712	457,366
2042	28,927	31,000	896,737	82,636	208,853	—	—	—	605,249	130,311	474,938
2043	28,644	31,000	887,963	81,651	208,294	—	14,101	—	583,916	134,729	449,187

Year	LHM Production (Mt)	LHM Price (US$/t)	Total Revenue ($ x 1,000)	Royalties ($ x 1,000)	Total Operating Costs[1] ($ x 1,000)	Initial Capital Cost ($ x 1,000)	Major Maintenance Capital Cost [2] ($ x 1,000)	Abandonment Capital Cost ($ x 1,000)	Before Tax Cash Flow ($ x 1,000)	Income Tax ($ x 1,000)	After Tax Cash Flow ($ x 1,000)
2044	28,352	31,000	878,911	80,636	207,718	—	14,101	—	576,455	134,937	441,518
2045	28,056	31,000	869,723	79,606	207,133	—	14,101	—	568,883	133,804	435,078
2046	27,757	31,000	860,464	78,567	206,544	—	14,101	—	561,251	132,242	429,009
2047	27,458	31,000	851,194	77,527	205,954	—	—	—	567,712	121,677	446,035
2048	27,159	31,000	841,928	76,488	205,365	—	14,101	—	545,974	126,002	419,972
2049	26,862	31,000	832,726	75,456	204,779	—	14,101	—	538,390	126,182	412,208
2050	26,567	31,000	823,562	74,429	204,196	—	14,101	—	530,836	125,054	405,782
2051	26,271	31,000	814,410	73,403	203,613	—	14,101	—	523,293	123,511	399,781
2052	25,975	31,000	805,217	69,954	223,177	—	—	—	512,086	108,883	403,203
2053	25,677	31,000	795,996	68,920	222,591	—	14,101	—	490,384	113,217	377,167
2054	25,377	31,000	786,681	67,876	221,998	—	14,101	—	482,706	113,375	369,331
2055	25,073	31,000	777,267	66,820	221,399	—	14,101	—	474,947	112,199	362,748
2056	24,764	31,000	767,692	65,746	220,789	—	14,101	—	467,055	110,577	356,478
2057	24,451	31,000	757,991	64,659	220,172	—	—	—	473,160	99,930	373,230
2058	24,133	31,000	748,129	63,553	219,544	—	14,101	—	450,931	104,142	346,788
2059	23,810	31,000	738,106	62,429	218,906	—	14,101	—	442,669	104,166	338,502
2060	23,481	31,000	727,897	61,285	218,257	—	14,101	—	434,255	102,840	331,415
2061	23,148	31,000	717,573	60,127	217,600	—	14,101	—	425,745	101,075	324,669
2062	22,811	31,000	707,132	58,957	216,935	—	—	—	431,240	90,289	340,951
2063	22,471	31,000	696,600	57,776	216,265	—	14,101	—	408,458	94,374	314,084
2064	22,128	31,000	685,977	56,585	215,589	—	14,101	—	399,702	94,284	305,418

Year	LHM Production (Mt)	LHM Price (US$/t)	Total Revenue ($ x 1,000)	Royalties ($ x 1,000)	Total Operating Costs[1] ($ x 1,000)	Initial Capital Cost ($ x 1,000)	Major Maintenance Capital Cost [2] ($ x 1,000)	Abandonment Capital Cost ($ x 1,000)	Before Tax Cash Flow ($ x 1,000)	Income Tax ($ x 1,000)	After Tax Cash Flow ($ x 1,000)
2065	21,785	31,000	675,350	55,394	214,913	—	14,101	—	390,942	92,878	298,064
2066	21,443	31,000	664,727	54,203	214,237	—	14,101	—	382,186	91,057	291,129
2067	21,101	31,000	654,137	53,016	213,563	—	—	—	387,558	80,242	307,316
2068	20,761	31,000	643,579	51,833	212,891	—	14,101	—	364,754	84,322	280,432
2069	20,424	31,000	633,131	50,662	212,226	—	14,101	—	356,143	84,265	271,877
2070	20,090	31,000	622,793	49,503	211,568	—	14,101	—	347,621	82,914	264,707
2071	19,761	31,000	612,579	48,359	210,918	—	14,101	—	339,201	81,170	258,031
2072	19,435	31,000	602,474	47,227	210,275	—	—	—	344,973	70,447	274,525
2073	19,114	31,000	592,537	46,113	209,642	—	—	—	336,782	74,645	262,137
2074	18,799	31,000	582,754	45,017	209,020	—	—	—	328,717	74,714	254,003
2075	18,488	31,000	573,124	43,939	208,407	—	—	—	320,779	73,497	247,281
2076	18,181	31,000	563,623	33,958	207,802	—	—	27,404	294,459	63,529	230,931

Note: 1. Includes sustaining capital expenses. LHM = lithium hydroxide monohydrate. Numbers have been rounded.

Table 22-3: Economic Evaluation Results

Evaluation Metric	Units	Years 1–25	50 Year Life
Lithium hydroxide monohydrate average production	t/year	29,593	25,850
Lithium hydroxide monohydrate price	US$/t	31,601	31,344
Total initial capital	US$ x 1,000	2,465,476	2,465,476
Total sustaining capital	US$ x 1,000	375,755	1,263,699
Total maintenance capital	US$ x 1,000	282,022	507,640
Total abandonment capital	US$ x 1,000	—	27,407
Average annual operating cost	US$ x1000/year	194,776	187,403
Average operating cost	US$/t	6,582	7,250
Annual EBITDA	US$ x 1,000	648,070	530,844
Project unlevered IRR (pre-tax)	%	29.3	
Project unlevered IRR (after-tax)	%	24.7	
Project NPV @ 8% (after-tax)	US$ x1,000	3,720,301	
Payback period	Years	4	4

Note: EBITDA = earnings before taxation, depreciation and amortization. IRR = internal rate of return. NPV = net present value.

Grade sensitivity was excluded on the following basis:

- Brine-hosted lithium mineralization (grade) is demonstrably homogeneous both laterally and vertically across the entire Bashaw District;
- Declining grade, due to interaction of the reinjected brine from the injection wells reaching, fully or partially, with the production wells, is included in the economic analysis;
- A sensitivity for ± overall production volumes disconnects the production profile from the infrastructure as described, and is considered to be unrepresentative.

The sensitivity analysis results are presented in Table 22-4, Table 22-5, Table 22-6, and the changes in IRR and NPV are shown in the tornado charts included as Figure 22-1 and Figure 22-2, respectively.

The results of the sensitivity analysis demonstrate the economic viability of the project through the ranges of ± 20% for the variable change of capital cost estimate, operating cost estimate, and selling price. The project economics show the most significant impact to variations of the selling price followed by the capital cost estimate, and finally the operating cost estimate.

Table 22-4: Initial Capital and Major Maintenance and Abandonment Cost Sensitivity Analysis Results

Financial Summary	Base Case (US$ x 1,000)	+20% Capital Cost (US$ x 1,000)	-20% Capital Cost (US$ x 1,000)
Initial capital cost	2,465,476	2,958,571	1,972,381
Major maintenance cost	507,640	609,168	406,112
Abandonment cost	27,404	32,885	21,923
Project Economics			
Project NPV @ 8% (after-tax)	3,720,301	3,282,044	4,156,339
Project unlevered IRR (after-tax) (%)	24.6	20.3	30.9

Note: NPV = net present value. IRR = internal rate of return.

Table 22-5: Operating Cost and Sustaining Capital Cost Sensitivity Analysis Results

Financial Summary	Base Case (US$ x 1,000)	+20% Operating &Maintenance Cost (US$ x 1,000)	-20% Operating &Maintenance Cost (US$ x 1,000)
Average annual operating and sustaining costs	(212,677)	(255,212)	(170,142)
Project Economics			
Project NPV @ 8% (after-tax)	3,720,301	3,3736,339	4,079,719
Project unlevered IRR (after-tax) (%)	24.6	23.2	26.2

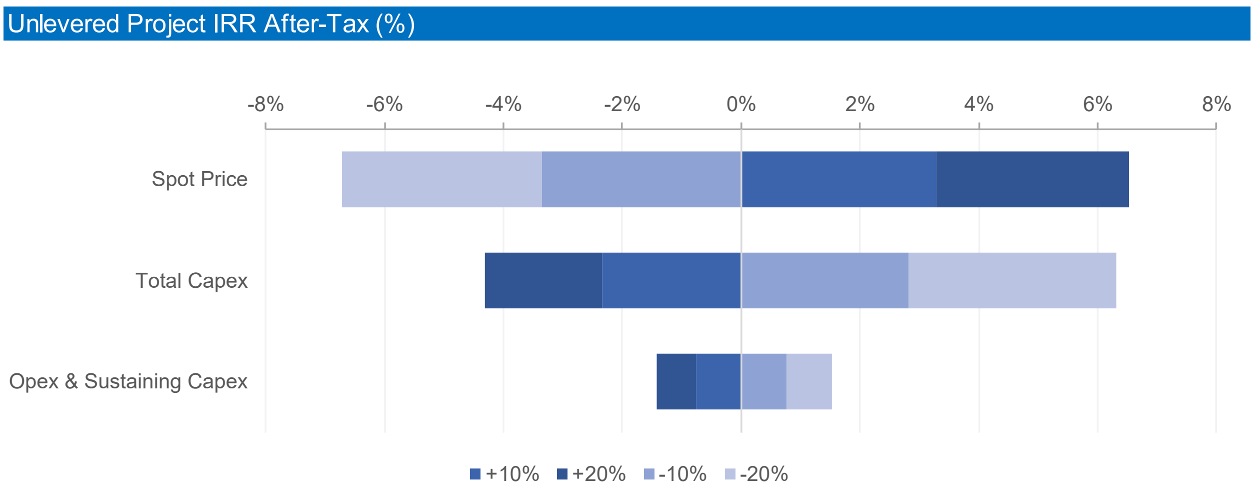
Note: NPV = net present value. IRR = internal rate of return.

Table 22-6: Selling Price Sensitivity Analysis Results

Financial Summary	Base Case (US$ x 1,000)	+20% Selling Price (US$ x 1,000)	-20% Selling Price (US$ x 1,000)
Total Revenue	40,509	48,611	32,408
Average Price US$/t	31,344	37,613	25,075
Project Economics			
Project NPV @ 8% (after-tax)	3,720,301	5,251,377	2,179,994
Project unlevered IRR (after-tax) (%)	24.6	31.2	17.9

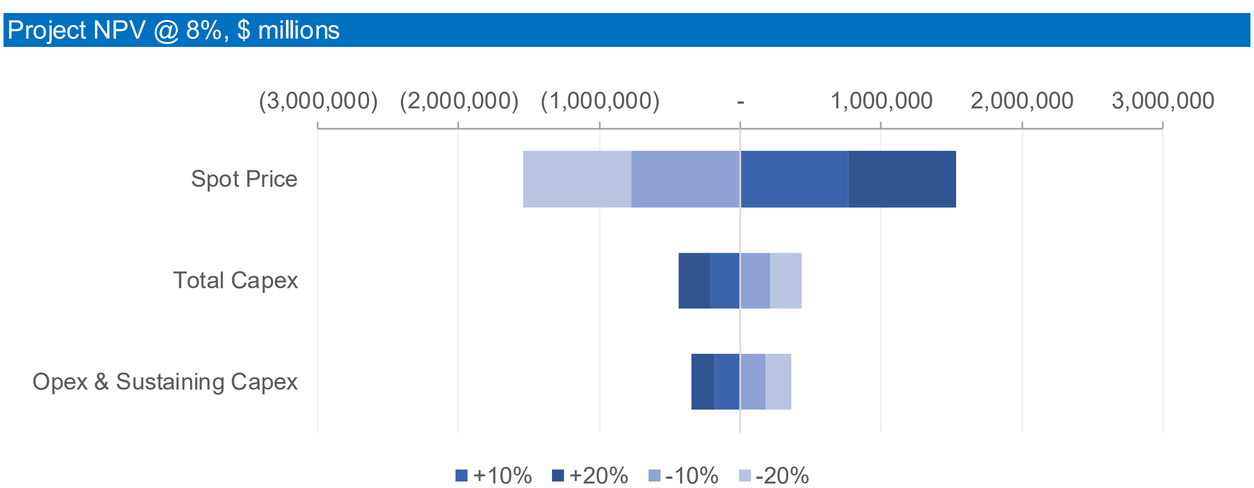
Note: NPV = net present value. IRR = internal rate of return.

Figure 22-1: IRR Tornado Chart



Note: Figure prepared by E3, 2024. Capex = capital cost estimate. Opex = operating cost estimate. Chart shows change in IRR versus base case.

Figure 22-2: NPV Tornado Chart



Note: Figure prepared by E3, 2024. Capex = capital cost estimate. Opex = operating cost estimate. Chart shows change in NPV versus base case.

23.0 ADJACENT PROPERTIES

This section is not relevant to this Report.

24.0 OTHER RELEVANT DATA AND INFORMATION

This section is not relevant to this Report.

25.0 INTERPRETATION AND CONCLUSIONS

25.1 Introduction

The QPs note the following interpretations and conclusions in their respective areas of expertise, based on the reviews and interpretations of data available for this Report.

25.2 Mineral Tenure, Surface Rights, Water Rights, Royalties and Agreements

Information obtained from E3 experts supports that the mineral tenure held is valid, and the granted exploration licence is sufficient to support Brine Resource and Brine Reserve estimation.

Surface rights are owned mainly by private landowners over the Bashaw District, and E3 currently leases three surface locations from private owners for their three well pads. Drilling pad locations will be leased from individual property owners for an annual fee and must be reclaimed when the terms of the surface lease have been fulfilled or terminated. For facilities, surface locations can either be purchased or leased under the same conditions, and it is required that they are also reclaimed when the facility is decommissioned or abandoned.

Under the *Surface Rights Act*, the holder to the rights to mines and minerals has a right to access the surface in order to work those interests. However, the *Surface Rights Act* requires an operator to obtain the surface owner's consent prior to entering the surface. If consent cannot be negotiated, then to avoid the risk of sterilization, the resource company can apply to the surface rights board for a right of entry order, and the surface rights board/tribunal would decide how to resolve this issue and how the surface owner would be compensated. The QP considers that there is reasonable support for the assumption that E3 will gain surface access as needed to support the project development.

There are no known private or regulatory royalties that apply to the Project.

25.3 Geology and Mineralization

The lithium brine in the Bashaw District is considered to be an example of a lithium-rich brine deposit.

The geological understanding of the settings, lithologies, and structural and alteration controls on the brine within the Leduc reservoir is sufficient to support estimation of Brine Resources and Brine Reserves. The geological knowledge of the area is also considered sufficiently acceptable to reliably inform production planning.

Exploration potential exists within the Project area as E3's mineral tenure includes rights to all brine-hosted minerals from surface to the basement within those rights. Exploration for lithium from other lithological units outside of the Leduc Formation is an E3 exploration focus, with exploration ongoing in these units. E3 has identified elevated lithium concentrations in the Nisku Aquifer, which overlies the Leduc Formation.

25.4 Exploration, Drilling and Analytical Data Collection in Support of Brine Resource Estimation

E3 excluded the publicly-available data from estimation support because it is unclear if the samples were subject to an equivalent of E3's standard operating procedure or if a chain of custody to ensure sample security was used.

E3's exploration drilling provided suitable data to characterize the interior lagoonal facies of the Bashaw Reef trend including core, geophysical logs of porosity, vertically-discretized brine samples, and production test data. These data are suitable to inform the Brine Resource and Brine Reserve estimation;

E3's sampling methods are acceptable for Brine Resource and Brine Reserve estimation.

Sample preparation, analysis and security were generally performed in accordance with exploration best practices and industry standards for brines.

25.5 Metallurgical Testwork

Metallurgical testwork and associated analytical procedures were appropriate to establish the optimal processing routes, and were performed using samples that are typical of the brine concentrations found within the Leduc reservoir.

Testing demonstrated consistent direct lithium extraction lithium recovery from brine with a reported average of 95.04% ±0.79% observed during testing. The low variability of the brine chemistry will enable consistent lithium recovery.

Downstream of the direct lithium extraction process, it is anticipated that 98% of the lithium recovered by the direct lithium extraction will be converted into solid lithium carbonate. The redissolution of lithium carbonate and precipitation of lithium hydroxide will recover 96.9% of the lithium for a final overall process recovery of 90.4% lithium into a lithium hydroxide monohydrate product.

Brine chemistry across the Bashaw district is relatively consistent with a narrow range of concentrations for lithium as well as for other species. E3 has collected samples across 65+ townships and has also collected a vertical brine profile in their most recent test wells and found the composition to have low variability.

Silicon, boron, sodium, magnesium and calcium are the expected deleterious elements present in the Leduc brine. The concentrations of these elements are expected to be steady during plant operations. In compliance with battery grade lithium hydroxide monohydrate specifications, product is to contain <0.01 mg/L each of silicon, boron, sodium, magnesium and calcium.

25.6 Brine Resource Estimates

Brine Resources are reported using the 2014 CIM Definition Standards.

Factors that may affect the estimates include:

- The resource estimate methodology is dependant on the assumption that the depleted brine will be reinjected into the host reservoir;
- The Brine Resource estimate used a geostatistical approach accounting for uncertainty in porosity measurements that leveraged a significant amount of publicly available data from historical petroleum exploration in the reservoir. Therefore, existing porosity, permeability, and grade measurements are still mainly concentrated in the hydrocarbon saturated portions of the reservoir. While the P50 connected porosity volume may be an overestimate of the actual connected porosity in the reservoir, the QPs believe that the geostatistical approach captured the potential range of uncertainty in connected porosity that could impact the resource estimate which was found to be 12% (P10–P90);
- For the purposes of this Report, the porosity system has been treated as a single continuum of porosity, and de-weighted the fracture porosity by using the K90 core permeability measurements rather than the maximum permeability. If the exchange between matrix and fractures is delayed, this could affect the ability to extract the Brine Resource from the matrix porosity.

25.7 Brine Reserve Estimates

Brine Reserves are reported using the 2014 CIM Definition Standards.

Factors that may affect the estimate include:

- E3's ability to raise sufficient capital to develop the Clearwater Project as outlined in Section 16. Should insufficient capital be available, a smaller-scale development could be considered, which would recover fewer Brine Reserves than those included in the 2024 PFS;
- Other factors that could affect development of the Brine Reserves are changes in the assumptions regarding reservoir factors (brine volume, reservoir deliverability, lithium concentration); cost factors (operating and capital costs); processing factors (facility on time, processing losses); lithium market and pricing; supply of materials (both building materials and process materials and chemicals); environmental, social license, and regulatory considerations (approvals and licenses).

25.8 Mine Plan

Reservoir water will be pumped to the surface from a production well as produced brine. The produced brine will be processed at the surface to remove the lithium, leveraging direct lithium extraction technology. The lithium-depleted brine will be injected into the reservoir using injection wells for pressure support and to maintain the reservoir voidage replacement ratio.

The inlet volume required to the Central Processing Facility is 232,500m^3/d, which can be met and maintained from 93 wells for the full 50 years of production, without requiring sustaining well capital. The reservoir development plan is to drill up to five wells from each of 38 pads in the project area, for a total of 93 producers and 93 injectors, each with a rate of 2,500 m^3/d.

25.9 Recovery Plan

The process plant flowsheet design was based on testwork results, previous study designs and industry standard practices.

The Clearwater Project will produce battery-grade lithium hydroxide monohydrate from Leduc Formation brine. The Central Processing Facility will process 232,500 m^3/d of brine to produce battery grade lithium hydroxide monohydrate at the expected combined lithium recovery performance of 90.4% from the direct lithium extraction technology, lithium refining and conversion steps in the process. The brine will have an average lithium concentration of 75 mg/L ±5 mg/L. The planned production life is 50 years. Applying the Central Processing Facility assumed availability of 92%, the initial facility production rate will be 32,250 t/a.

The process facilities to be used are appropriate for brine recovery.

25.10 Infrastructure

Key Project infrastructure will include a third-party operated cogeneration facility for the power supply, 93 each of producer and injector wells with associated wellpads, brine production and reinjection pipelines, Central Processing Facility, roads, and support buildings (office space; control room; warehouse for storage of spares and sales product; laboratory; security; first aid).

The cogeneration facility will be connected to an existing transmission power line in close proximity to the Central Processing Facility to provide redundancy and reliability for power supply in the event of a cogeneration facility outage. Power for the well pads will also be supplied by the cogeneration facility through power infrastructure built and operated by a local power distribution company. The facility will include natural gas-fired turbines. A portion of the steam generated from waste heat will be used within the Central Processing Facility to satisfy all utility steam requirements during normal operations.

The workforce will live in surrounding communities. No onsite accommodation is planned.

25.11 Environmental, Permitting and Social Considerations

25.11.1 Environmental Considerations

There have been two environmental studies completed for the Central Processing Facility, including a reconnaissance-level survey to identify potential environmental constraints, and a Phase 1 environmental site assessment to identify potential environmental concerns, including those from previous land uses.

A stormwater pond will be required to manage surface water run-off, which will be designed to meet a 1-in-100-year flood event. Surface water run-off within the Central Processing Facility boundary will be managed in accordance with the industrial wastewater limits.

A groundwater monitoring program will likely be required to monitor and detect potential impacts to fresh groundwater resources in the vicinity of the Central Processing Facility.

There is a local market for calcium carbonate and E3 is exploring ways to sell this product into the cement industry and eliminate this product as waste.

25.11.2 Permitting Considerations

E3 has not yet applied for the regulatory approvals required for the Project. Key components that will require permitting include: the mineral facility (Central Processing Facility), well pads with mineral wells, and accompanying mineral scheme(s), and pipeline network required to transport brine to the Central Processing Facility for processing and refinement.

25.11.3 Social Considerations

E3 has developed a strategy to address social licence for the project, which is a combination of adhering to instructions in various Alberta Energy Regulator Directives, and in the *Responsible Energy Development Act,* and a planned broader consultation process.

The Clearwater Project is located on freehold-owned surface land. It is unlikely that there will be any Aboriginal Consultation Office determination on level of consultation for the Project.

E3 will seek to engage with First Nations to understand and address their values, concerns and interests in the Project, and potentially explore options for economic development.

25.12 Markets and Contracts

The market assumptions were supported by research from specialist commodity firms.

A detailed future pricing study for lithium chemicals was developed for the Project using data from trusted research firms, covering battery-grade lithium carbonate equivalent and lithium hydroxide monohydrate prices for China, Japan, and Korea, as well as spodumene prices for China. The price forecast for lithium hydroxide monohydrate was based on yearly forecast from 2027 to 2034, where the long-term price used was the 2023 price of $31,000/t lithium hydroxide monohydrate, in Benchmark Mineral Intelligence's Q1 2024 report, prepared in March 2024.

It is anticipated that material contracts for the Project will include power, concentrating, refining, transportation, handling, and product offtake. Any future contracts would be in line with similar contracts in Alberta. No contracts were in place at the Report effective date.

25.13 Capital Cost Estimates

The capital cost estimate includes engineering, materials, equipment, and labour required to design, build, and construct commercial lithium extraction wells, a gathering system and a Central Processing Facility and produce lithium hydroxide monohydrate over a 50-year production life.

The initial capital cost is estimated at US$2,465 million.

Major maintenance capital cost is estimated at US$507 million.

Sustaining capital cost is estimated at US$1,264 million.

Abandonment, decommissioning and reclamation for producer and injector wells, gathering systems and the Central Processing Facility is estimated at $US27.4 million.

25.14 Operating Cost Estimates

The annual operating cost was calculated using quantity and pricing information provided through vendor quotes or by engineering calculation. An allowance was assumed for some miscellaneous costs.

The operating costs are average annual costs over the 50-year operating life of the project and are reported in US$/year.

The total average annual operating cost is US$187.4 million (excluding sustaining capital costs).

25.15 Economic Analysis

The economic analysis combines the production profile from the Leduc reservoir provided by the production well network and the estimated capital and operating costs to extract, pipe and process the brine and further refine it into a saleable lithium hydroxide monohydrate.

The economic analysis was prepared using a discounted cash flow economic model, showing both pre-tax and post-tax results. The model includes government royalties and taxes but excludes any commercial royalties/payments. The results include NPV for an 8% discount rate, IRR, and a sensitivity analysis of key inputs.

The post-tax NPV is US$3.72 billion, the post-tax IRR is 24.6%, and the payback period is four years.

The results of the sensitivity analysis demonstrate the economic viability of the project through the ranges of ± 20% for the variable change of capital cost estimate, operating cost estimate, and selling price. The project economics show the most significant impact to variations of the selling price followed by the capital cost estimate, and finally the operating cost estimate.

25.16 Risks and Opportunities

25.16.1 Risks

The QPs identified the following risks in their areas of expertise.

Brine Resource and Brine Reserve Estimates

- Re-injection fails to maintain reservoir pressure;
- Existing porosity, permeability, and grade measurements are mainly concentrated in the hydrocarbon pools within the Bashaw District;
- Transfer of lithium from the rock matrix porosity to fractures could be delayed.

Reservoir Development Plan

- Potential production and injection rates for full Leduc perforations are currently calculated based on a single flow test;
- Hydraulic continuity between interior and margin areas was inferred from regional data, not physically validated by long-term pressure transient data;
- The assumptions as to timing and magnitude of break-through of lithium-depleted brine that is re-injected into the reservoir reaching the production wells;
- The ability to maintain reservoir pressures to support production flow rates has been modelled and will need to be validated through actual operational data;
- Relationship of porosity to permeability is variable across the Bashaw District area and the specific factors controlling variability (geological facies, diagenetic processes) have not been discretely represented in the current reservoir model.

Process Design

- Lithium sorbent degradation rates over time/cycles could be higher than anticipated;
- Consumption/fouling rates for reverse osmosis membranes could be higher than anticipated;
- Solids in brine are greater than anticipated, resulting in the need for solid removal equipment;
- Sour brine could have a detrimental long term impact on sorbent degradation;
- Potential for H2S to evolve from brine in the plant;
- Materials of construction failure:
  - Availability at 92% is at the high end for most mineral processing plants however is achieved from industrial processing facilities currently. Currently minor maintenance requirements are assumed to align into major maintenance windows; however, a detailed minor maintenance schedule shall be constructed to update the total availability;

- Despite the chemistry being well understood for the post direct lithium extraction stages, varying incoming chemistry and reagent quality is a risk and further testwork is being conducted to understand the impact;

Regulatory

- Pore space competition between brine-hosted resources and reserves and carbon capture utilization and storage interests;
- Freehold land ownership and crown ownership for mineral permits not held by E3 will require agreements to equitably produce.

Economics

- Operating costs and capital costs could be higher than estimated;
- Lithium prices could be lower than estimated.

25.16.2 Opportunities

There is opportunity to further increase confidence in the Brine Resource and Brine Reserve estimates and reduce risks through additional data collection, flow tests and monitoring during future construction, commissioning, and production phases and incorporation and assessment of new information using the reservoir model.

Recovery is based on current testwork conducted by E3 and independent vendors and there is both a risk and opportunity on the total recovery, which will be further explored by future testwork and pilot plant trials.

E3 is investigating mechanisms to sell the calcium carbonate produced to the cement industry, thereby creating another potential revenue source and a zero-waste facility.

25.17 Conclusions

Under the assumptions described in this Report, the proposed LOM plan is achievable, and the economic analysis supports declaration of Brine Reserves.

26.0 RECOMMENDATIONS

26.1 Introduction

Two work phases are recommended.

The first work phase will culminate in a feasibility study. Assuming the results of the feasibility study are positive, E3 should evaluate a final investment decision in a second work phase.

The estimated budget to complete the phases is about US$66 M.

26.2 Phase 1

The initial work program includes the following.

- Brine Resources and Brine Reserves: additional drilling and testing of existing wells; reservoir simulations;
- Lithium processing: testing to observe the sorbent longevity and susceptibility of thermal shock, any sorbent performance variability or loading limitation, and optimal column configuration; additional testing to de-risk unit operations;
- Engineering studies.

The total estimated costs for Phase 1 are summarized in Table 26-1, and are approximately US$9 million. Phase 1 would result in the completion of a feasibility study.

26.3 Phase 2

Assuming a positive result from the feasibility study work phase, a second work phase would be completed to support an investment decision, and should include:

- Brine Resources and Brine Reserves: additional drilling and testing of existing wells; reservoir simulations;
- Engineering studies.

The total estimated costs for Phase 2 are summarized in Table 26-2, and are approximately US$57 million.

Table 26-1: Phase 1 Work Program

Area	Recommended Work Program	Work Program Cost (US$ x 1,000)
Brine Resource and Brine Reserve characterization	Additional drilling/testing of existing wells	4,500
	Additional reservoir simulations to model flow characteristics for planning of a well network production and injection scheme	60
Lithium processing:	Testing to observe the sorbent longevity and susceptibility of thermal shock, any sorbent performance variability or loading limitation, and optimal column configuration	250
	Long term repeated cycling of adsorption-rinse-desorption-rinse	250
	Under sour brine conditions	500
Process design	Testing to de-risk unit operations	100
	Impact on ion exchange and evaporative processes	400
	Scaling or fouling of reverse osmosis membranes in the production of concentrated lithium chloride solution	100
	Confirm solubility equilibria	100
	Confirm fluid-fluid and fluid-rock compatibility	150
Pre-front end engineering design	Engineering design and documentation to complete feasibility study	2,500
Total		***8,910***

Table 26-2: Phase 2 Work Program

Area	Recommended Work Program	Work Program Cost (US$ x 1,000)
Brine Resource and Brine Reserve characterization	Additional drilling/testing of existing wells	26,800
	Additional reservoir simulations to model flow characteristics for planning of a well network production and injection scheme	120
Front end engineering design	Engineering design and documentation to support final investment decision	30,000
Total		***56,920***

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