E3 Metals Corp.

NI 43-101 Technical Report

Preliminary Economic Assessment
Clearwater Lithium Project

Alberta, Canada
December 21, 2020

Completed by:

GLJ Fluid Domains Scovan NORAM

Forward Looking Information Statement

This Report contains forward-looking statements regarding E3 Metals Corp. ("E3 Metals" or the "Company") for the purposes of Canadian securities laws. Generally, forward-looking statements 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". Forward-looking statements are based on the opinions and estimates of E3 Metals as of the date such statements are made.

These forward-looking statements relate to, among other things, resource estimates, grades and recoveries, development plans, mining methods and metrics including recovery process and, mining and production expectations including expected cash flows, capital cost estimates and expected life of mine, operating costs, the expected payback period, receipt of government approvals and licenses, time frame for construction, financial forecasts including net present value and internal rate of return estimates, tax and royalty rates, and other expected costs.

Forward-looking information is necessarily based upon a number of estimates and assumptions that, while considered reasonable, are inherently subject to significant political, business, economic and competitive uncertainties and contingencies. There may be factors that cause results, assumptions, performance, achievements, prospects or opportunities in future periods not to be as anticipated, estimated or intended.

There can be no assurances that forward-looking information and statements will prove to be accurate, as many factors and future events, both known and unknown could cause actual results, performance or achievements to vary or differ materially, from the results, performance or achievements that are or may be expressed or implied by such forward-looking statements contained herein or incorporated by reference. Accordingly, all such factors should be considered carefully when making decisions with respect to the Company's project described herein, and prospective investors should not place undue reliance on forward-looking information. Forward-looking information in this technical report is as of the issue date, December 21, 2020. E3 Metals will not update any forward-looking statements except in accordance with requirements of applicable laws.

Certificate of Qualified Person

To accompany the Report entitled "NI 43-101 Technical Report Preliminary Economic Assessment Clearwater Lithium Project" (the "Technical Report"):

Effective Date: November 16, 2020
Issue Date: December 21, 2020

I, **Gordon MacMillan**, P.Geol., hereby state that:

1. I am currently engaged as a Hydrogeological Consultant;
2. I am a graduate of the University of Calgary with a Bachelor of Science in Applied and Environmental Geology (1998);
3. I am a Registered Professional Geologist through the Association of Professional Engineers and Geoscientists of Alberta, Membership Number 63537;
4. I have practiced as a professional in hydrogeology since 2000 and have 20 years of experience in mining, water supply, water injection, and solute migration. I have performed computer 3D modelling of groundwater flow, solute transport and heat flow. I have worked with multi-discipline teams to develop and model detailed models of large-scale solute migration;
5. I have read the definition of "Qualified Persons" set out in National Instrument 43-101 Standards of Disclosure for Mineral Projects (the "Instrument" or "NI 43-101") and certify that by reason, I fulfill the requirements to be a "Qualified Person" for the purposes of NI 43-101;
6. I am responsible for the preparation of Sections 4, 5, 6, 7, 8, 9, 10, 11, 12, 14, and 23 of the report entitled "NI 43-101 Technical Report Preliminary Economic Assessment Clearwater Lithium Project" with effective date of November 16, 2020 (the "Technical Report");
7. I have reviewed the field sampling Standard Operating Procedure (SOP) and the Laboratory Testing SOP developed by E3 Metals to ensure consistent and accurate sample collection and analysis. I have reviewed the Quality Assurance/Quality Control results provided by E3 Metals and reviewed the reports provided for each lithium sample by the laboratory on the property that is the subject of the Technical Report (the "Property"). I have also witnessed E3 Metals Corporation's collection of field samples on March 23, 2018 site visit on a contiguous portion of the Leduc reef, north of the CCRA.
8. At the effective date of the Technical Report, to the best of my knowledge, information, and belief, the Technical Report, or part that I am responsible for, contains all scientific and technical information that is required to be disclosed to make the Technical Report not misleading.
9. I do not hold, nor do I expect to receive, any securities or any other interest in any corporate entity, private or public, with interests in the properties that are the subject of this report or in the properties themselves, nor do I have any business relationship with any such entity apart from a professional consulting relationship with the issuer, nor to the best of my knowledge do I have any interest in any securities of any corporate entity with property within a two (2) kilometer distance of any of the subject properties.

10. I am independent of E3 Metals Corporation according to the criteria stated in Section 1.5 of the Instrument;
11. I have read NI 43-101 and Form NI 43-101F1 and the Technical Report has been prepared in compliance with that instrument and form.
12. I consent to the public filing of the Technical Report titled "NI 43-101 Technical Report Preliminary Economic Assessment Clearwater Lithium Project" (the "Technical Report") by E3 Metals Corp. I also consent to any extracts from or a summary of the Technical Report in any type of disclosure document with any stock exchanges or other regulatory authority and any publication by them, including electronic publication in the public company files on the websites accessible by the public, of the Technical Report of E3 Metals Corp.

DATED this December 18, 2020, at Cochrane, Alberta, Canada

Gordon MacMillan, P.Geol.

PROFESSIONAL GEOLOGIST ALBERTA
GORDON J. MacMILLAN
Dec 18, 2020

Certificate of Qualified Person

To accompany the report entitled "NI 43-101 Technical Report Preliminary Economic Assessment Clearwater Lithium Project" (the "Technical Report"):

Effective Date: November 16, 2020
Issue Date: December 21, 2020

I, **Werner Vorster**, PhD, P.Eng., C. Eng., hereby state that:

1. I am a process engineer employed by NORAM Engineering and Constructors Ltd located at 200 Granville Street, Vancouver, BC, V6C 1S4;
2. I am a graduate of the University of the Witwatersrand, Johannesburg, South Africa with a BSc Eng (Chem) degree (1997) and the University of Birmingham, Birmingham, England with a PhD in Chemical Engineering (2001);
3. I am a Registered Professional Engineer (P.Eng.) with the Engineers and Geoscientists of British Columbia (EGBC) with Registration Number 49046 as well as a Chartered Engineer (C.Eng.) with the Engineering Council in the United Kingdom with Registration Number 554787;
4. I have practiced as Project Process Engineer since 2001 and have 19 years of experience in the chemical and mineral processing industries across all project phases from conceptual design to commissioning across a number of different commodities;
5. I have read the definition of "Qualified Persons" set out in National Instrument 43-101 Standards of Disclosure for Mineral Projects (the "Instrument" or "NI 43-101") and certify that by reason, I fulfill the requirements to be a "Qualified Person" for the purposes of NI 43-101;
6. I am responsible for the preparation of Sections 1, 2, 3, 13, 17, 19, 24, 25, 26, and 27 of the report entitled "NI 43-101 Technical Report Preliminary Economic Assessment Clearwater Lithium Project" with effective date of November 16, 2020 (the "Technical Report");
7. At the effective date of the Technical Report, to the best of my knowledge, information, and belief, the Technical Report, or part(s) thereof that I am responsible for, contains all scientific and technical information that is required to be disclosed to make the Technical Report not misleading.
8. I do not hold, nor do I expect to receive, any securities or any other interest in any corporate entity, private or public, with interests in the properties that are the subject of this report or in the properties themselves, nor do I have any business relationship with any such entity apart from a professional consulting relationship with the issuer, nor to the best of my knowledge do I have any interest in any securities of any corporate entity with property within a two (2) kilometer distance of any of the subject properties.
9. I am independent of E3 Metals Corporation according to the criteria stated in Section 1.5 of the Instrument;
10. I have read NI 43-101 and Form NI 43-101F1 and the Technical Report has been prepared in compliance with that instrument and form.

11. I consent to the public filing of the Technical Report titled "NI 43-101 Technical Report Preliminary Economic Assessment Clearwater Lithium Project" (the "Technical Report") by E3 Metals Corp. I also consent to any extracts from or a summary of the Technical Report in any type of disclosure document with any stock exchanges or other regulatory authority and any publication by them, including electronic publication in the public company files on the websites accessible by the public, of the Technical Report of E3 Metals Corp.

DATED December 21, 2020, at Vancouver, British Columbia, Canada

PROFESSIONAL
PROVINCE OF
Dr. W. VORSTER
49046
BRITISH COLUMBIA
ENGINEER

Werner Vorster, PhD, P.Eng., C. Eng.

Certificate of Qualified Person

To accompany the report entitled "NI 43-101 Technical Report Preliminary Economic Assessment Clearwater Lithium Project" (the "Technical Report"):

Effective Date: November 16, 2020
Issue Date: December 21, 2020

I, **Damian Bransby-Williams**, P.Eng., hereby state that:

1. I am currently engaged as a Professional Engineer employed by Scovan Engineering Inc;
2. I am a graduate of the University of Calgary with a Bachelor of Science in Mechanical Engineering (2003);
3. I am a Registered Professional Engineer through the Association of Professional Engineers and Geoscientists of Alberta, Membership Number 77731;
4. I have practiced as a professional in Engineering since 2009 and have 17 years of experience in managing projects, designing oil and gas facilities and pipelines;
5. I have read the definition of "Qualified Persons" set out in National Instrument 43-101 Standards of Disclosure for Mineral Projects (the "Instrument" or "NI 43-101") and certify that by reason, I fulfill the requirements to be a "Qualified Person" for the purposes of NI 43-101;
6. I am responsible for the preparation of Section 21 and 22 of the report entitled "NI 43-101 Technical Report Preliminary Economic Assessment Clearwater Lithium Project" with effective date of November 16, 2020 (the "Technical Report");
7. At the effective date of the Technical Report, to the best of my knowledge, information, and belief, the Technical Report, or part that I am responsible for, contains all scientific and technical information that is required to be disclosed to make the Technical Report not misleading.
8. I do not hold, nor do I expect to receive, any securities or any other interest in any corporate entity, private or public, with interests in the properties that are the subject of this report or in the properties themselves, nor do I have any business relationship with any such entity apart from a professional consulting relationship with the issuer, nor to the best of my knowledge do I have any interest in any securities of any corporate entity with property within a two (2) kilometer distance of any of the subject properties.
9. I am independent of E3 Metals Corporation according to the criteria stated in Section 1.5 of the Instrument;
10. I have read NI 43-101 and Form NI 43-101F1 and the Technical Report has been prepared in compliance with that instrument and form.
11. I consent to the public filing of the Technical Report titled "NI 43-101 Technical Report Preliminary Economic Assessment Clearwater Lithium Project" (the "Technical Report") by E3 Metals Corp. I also consent to any extracts from or a summary of the Technical Report in any type of disclosure document with any stock exchanges or other regulatory authority and any publication by them, including electronic publication in the public company files on the websites accessible by the public, of the Technical Report of E3 Metals Corp.

DATED this December 18, 2020, at Calgary, Alberta, Canada,

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Damian Bransby-Williams, P.Eng.

PROFESSIONAL ENGINEER
DAMIAN BRANSBY-WILLIAMS
ALBERTA

Dec. 18 2020

Certificate of Qualified Person

To accompany the report entitled "NI 43-101 Technical Report Preliminary Economic Assessment Clearwater Lithium Project" (the "Technical Report"):

Effective Date: November 16, 2020
Issue Date: December 21, 2020

I, **Scott Pattinson**, P.Eng., hereby state that:

1. I am currently engaged as a Professional Engineer employed by Scovan Engineering Inc.;
2. I am a graduate of the University of Calgary with a Bachelor of Science in Chemical Engineering (1986);
3. I am a Registered Professional Engineer through the Association of Professional Engineers and Geoscientists of Alberta, Membership Number 45262;
4. I have practiced as a professional in Engineering since 1988 and have 30+ years of experience with the process design of industrial energy projects. My experience ranges from gas processing, water treatment, thermal heavy oil facilities, to power generation.
5. I have read the definition of "Qualified Persons" set out in National Instrument 43-101 Standards of Disclosure for Mineral Projects (the "Instrument" or "NI 43-101") and certify that by reason, I fulfill the requirements to be a "Qualified Person" for the purposes of NI 43-101;
6. I am responsible for the preparation of Section 18 of the report entitled "NI 43-101 Technical Report Preliminary Economic Assessment Clearwater Lithium Project" with effective date of November 16, 2020 (the "Technical Report");
7. At the effective date of the Technical Report, to the best of my knowledge, information, and belief, the Technical Report, or part that I am responsible for, contains all scientific and technical information that is required to be disclosed to make the Technical Report not misleading.
8. I do not hold, nor do I expect to receive, any securities or any other interest in any corporate entity, private or public, with interests in the properties that are the subject of this report or in the properties themselves, nor do I have any business relationship with any such entity apart from a professional consulting relationship with the issuer, nor to the best of my knowledge do I have any interest in any securities of any corporate entity with property within a two (2) kilometer distance of any of the subject properties.
9. I am independent of E3 Metals Corporation according to the criteria stated in Section 1.5 of the Instrument;
10. I have read NI 43-101 and Form NI 43-101F1 and the Technical Report has been prepared in compliance with that instrument and form.
11. I consent to the public filing of the Technical Report titled "NI 43-101 Technical Report Preliminary Economic Assessment Clearwater Lithium Project" (the "Technical Report") by E3 Metals Corp. I also consent to any extracts from or a summary of the Technical Report in any type of disclosure document with any stock exchanges or other regulatory authority and any publication by them,

including electronic publication in the public company files on the websites accessible by the public, of the Technical Report of E3 Metals Corp.

DATED this December 18, 2020, at Calgary, Alberta, Canada,

Scott Pattinson

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Scott Pattinson, P.Eng.

December 18 2020

Certificate of Qualified Person

To accompany the report entitled "NI 43-101 Technical Report Preliminary Economic Assessment Clearwater Lithium Project" (the "Technical Report"):

Effective Date: November 16, 2020
Issue Date: December 21, 2020

I, **Greg Owen**, P. Eng., hereby state that:

1. I am a VP Business Development for GLJ Ltd. 401 9 Ave SW Suite 1920, Calgary, AB;
2. I am a graduate of Montana Technological University with a B.Sc. in Environmental Engineering and my degree was granted in 1996;
3. I am a Registered Professional Engineer with Alberta Association of Professional Engineers Member number 59213;
4. I have practiced as a professional in the Energy Industry since 1996 and have 24 years of experience in Energy industry Engineering and Business Development;
5. I have read the definition of "Qualified Persons" set out in National Instrument 43-101 Standards of Disclosure for Mineral Projects (the "Instrument" or "NI 43-101") and certify that by reason, I fulfill the requirements to be a "Qualified Person" for the purposes of NI 43-101;
6. I am responsible for the preparation of Sections 16 and 20 of the report entitled "NI 43-101 Technical Report Preliminary Economic Assessment Clearwater Lithium Project" with effective date of November 16, 2020 (the "Technical Report");
7. At the effective date of the Technical Report, to the best of my knowledge, information, and belief, the Technical Report, or part that I am responsible for, contains all scientific and technical information that is required to be disclosed to make the Technical Report not misleading.
8. I do not hold, nor do I expect to receive, any securities or any other interest in any corporate entity, private or public, with interests in the properties that are the subject of this report or in the properties themselves, nor do I have any business relationship with any such entity apart from a professional consulting relationship with the issuer, nor to the best of my knowledge do I have any interest in any securities of any corporate entity with property within a two (2) kilometer distance of any of the subject properties.
9. I am independent of E3 Metals Corporation according to the criteria stated in Section 1.5 of the Instrument;
10. I have read NI 43-101 and Form NI 43-101F1 and the Technical Report has been prepared in compliance with that instrument and form.
11. I consent to the public filing of the Technical Report titled "NI 43-101 Technical Report Preliminary Economic Assessment Clearwater Lithium Project" (the "Technical Report") by E3 Metals Corp. I also consent to any extracts from or a summary of the Technical Report in any type of disclosure document with any stock exchanges or other regulatory authority and any publication by them, including electronic publication in the public company files on the websites accessible by the public, of the Technical Report of E3 Metals Corp.

DATED this December 21, 2020, at Calgary, Alberta, Canada,

Greg Owen, P. Eng.

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1 Summary

E3 Metals Corp “E3”, “E3 Metals” or the “Company”), an emerging lithium developer and leading lithium extraction technology innovator, is a public company with a head office located in Calgary, AB. The company trades on the Toronto Venture Exchange, as well as the OCT and Frankfurt markets (TSXV: ETMC | FSE: OU7A | OTC: EEMMF). Several Qualified Persons, including Gordon MacMillan (Fluid Domains Inc.), Damian Bransby-Williams (SCOVAN Engineering), Scott Pattinson (SCOVAN Engineering), Werner Vorster (NORAM Engineering) and Greg Owen (GLJ Ltd.), were retained by E3 Metals to prepare a technical report on the Preliminary Economic Assessment of the Clearwater Lithium Project in conformity to National Instrument 43-101 (NI 43-101) standards (the “PEA” or the “Report”).

1.1 Property Location and Ownership

The Alberta Lithium Project consists of 80 Metallic and Industrial Mineral Permits that overlie the Leduc Aquifer in Southern Alberta (Table 4-1). All permits are held 100% by 1975293 Alberta Ltd (Alberta Co), a wholly owned subsidiary of E3 Metals Corp. The property in its entirety contains 600,333 hectares (Ha) and is subdivided into 6 Sub-Project areas: Clearwater, Rocky, Exshaw, Drumheller, Sunbreaker and Meadowbrook-Rimbey. The preliminary economic assessment in this Report refers to a specific permit area called the Clearwater Lithium Project and previously referred to as the Central Clearwater Resource Area (CCRA).

1.2 Resource Estimate

The Inferred Mineral Resource Estimate, expressed as a mass of lithium carbonate equivalent, is 5.5 billion m^3 of brine at 74.6 mg/L, totaling 2.2 million tonnes of LCE using a conversion factor from elemental lithium of 5.323. The Inferred Mineral Resource estimate for the CCRA is based on the total volume of water in the effective porosity, the interpolated lithium concentration, a 0.5 production factor cut-off for the Innisfail Interior and Clearwater Interior production areas, and a 0.8 production factor cut-off for the Innisfail Margin and the Wimborne Margin.

The resource is classified as inferred because geological evidence is sufficient to imply but not verify geological, grade, or aquifer quality continuity. It is reasonably expected that the majority of the Inferred Mineral Resource Estimate could be upgraded to Indicated or Measured Mineral Resources with continued exploration.

1.3 Mining Methods and Aquifer Management Plan

For the purposes of this Preliminary Economic Assessment of the Clearwater Lithium Project, lithium enriched brine is sourced from deep vertical or deviated wells into the Leduc aquifer. This brine will be transported to the Central Processing Facility (CPF) via underground pipelines where lithium will be extracted from the lithium enriched brine. Lithium void brine is then returned to the Leduc aquifer through deep vertical or deviated injection wells. There are no surface mining methods utilized for this project as the brine is pumped from the subsurface aquifer and back into the aquifer; as such, it remains within in a closed-loop system. Primary extraction and the recovery of lithium is achieved through direct lithium extraction methods developed by the company and described in detail herein.

A well network with two production well groupings consisting of 21 wells at each grouping, are located north and south of the CPF. One injection well grouping location consisting of 21 wells is located proximal to the CPF. The line of injection wells is located approximately 15 km and 16 km away from the line of production wells to the north and south, respectively.

The selected well network, and its associated infrastructure, is designed to be capable of producing 140,000 m^3/day over a 20-year period with 92% availability, suitable for the production of 20,000 tonnes of lithium hydroxide monohydrate (LHM). The distance between each production well network and the injection well network was also designed such that the lithium void brine from the injection wells would reach the production wells after 20 years and achieve a maximum dilution of 5%.

1.4 Mineral Processing

Based on test work data received, a comprehensive design was developed which formed the basis of the preliminary process flow sheets. After pre-treatment (H_2S removal), the lithium in the brine is concentrated using E3 Metals' ion exchange sorbent material in a counter-current "sorbent-in-pulp" style system. The sorbent, assumed to be 1-2 mm in diameter, primarily absorbs lithium from brine in which the anion is mostly chloride. This process rejects the bulk of impurities which is returned to the well network in the bulk of the brine. The sorbent is eluted during which lithium is concentrated to approximately 870 mg/l Li^+ using anolyte recycled from the electrolysis circuit.

Following the E3 IX stage, the majority of the remaining species (Ca, Mg, Sr, Mn and B) are removed by precipitation as hydroxides and carbonates.

The Li^+ stream at this point is still too dilute for electrolysis and, after acidification to prevent membrane fouling, the lithium enriched eluate is further concentrated by Reverse Osmosis (RO) before the remaining divalent ions (Ca^{2+} and Mg^{2+}) are removed in the secondary Ion Exchange (IX) circuit.

The purified brine, containing mostly Li^+, K^+ and Na^+ cations, is suitable for electrolysis and crystallisation to form $LiOH.H_2O$.

All water removed from the brine prior to electrolysis is either used internally as make-up water or can be exported for use by others. The electrolysis process forms a weak sulphuric stream which is recycled to the elution stage reducing any need for large quantities of reagent.

1.5 Economics

A summary of the Project capital and operating costs are provided below. The full project summary of costs and the economic valuation based on the yearly production of 20,000 tonnes of LHM are detailed based on the capital and operating costs.

Table 1-1. Capital Costs

Capital Costs	Description	Costs (M CAD)	Costs (M USD)
Brine Production	Wells, pumps and pipelines	260.3	192.8
Brine Pre-Treatment	H_2S Removal	159.0	117.8
DLE Process (Li-IX)	Primary extraction of lithium from the brine	21.1	15.6
Lithium Production	Concentration, Polishing, Electrolysis and Crystallization	217.2	160.9
Power, Site, Transport and Labour Costs	Misc. Site and labour costs	47.4	35.1
Contingency (25%)	Applied to direct capital costs	107.7	79.8
Total		**812.7**	**602.0**
Sustaining Capital	Pump replacement, etc.	146.7	108.7

The total initial capital cost of the Project for 20,000 tonnes per year production of LHM is estimated at USD 602.0 Million, inclusive of direct and indirect costs and contingency. In addition, USD 108.7 Million of sustaining capital is also estimated, with the majority of this cost associated with the replacement of brine production pumps.

Table 1-2. Operating Costs

Operating Costs	Description	Total Annual Costs (M CAD)	Cost Per Tonne LHM (CAD)	Total Annual Costs (M USD)	Cost Per Tonne LHM (USD)
Brine Production	Well, pumps and pipeline (Incl. Power)	25.8	1,288	19.1	954
Brine Pre-Treatment	H_2S Removal (Incl. Power)	26.9	1,341	19.9	993

Operating Costs	Description	Total Annual Costs (M CAD)	Cost Per Tonne LHM (CAD)	Total Annual Costs (M USD)	Cost Per Tonne LHM (USD)
DLE Process (Li-IX)	Primary extraction of lithium from the brine (Incl. Power)	11.2	559	8.3	414
Lithium Production	Concentration, Polishing, Electrolysis and Crystallization (Incl. Power)	15.3	761	11.3	564
Site, Labour and G&A	Utility Power, Site, Transport, Labour and G&A Costs	19.7	988	14.6	732
Total		**98.8**	**4,936**	**73.2**	**3,656**

A total operating cost of USD 73.2 Million per year, or USD 3,656 per tonne LHM, are broken out by each major project step and are inclusive of direct and indirect costs. The majority of the operating costs are associated with reagents required within the system and power consumption.

Table 1-3. Preliminary Economic Assessment Results

Description	Units	CAD	USD
Production	tonnes/year LHM	20,000	20,000
Project Life	Years	20	20
Total Capital Cost (CAPEX)	M $	959.5	710.7
Total Initial Capital	M $	812.7	602.0
Average Annual Operating Costs (OPEX)	M $/year	98.8	73.2
Average Selling Price (LHM)	$/tonne LHM	19,007	14,079
Cash Operating Costs	$/tonne LHM	4936	3,656
Average Annual EBITDA	$	281.6	208.6
Pre-Tax Net Present Value ("NPV") (8% discount)	$	1,516.2	1,123.1

Description	Units	CAD	USD
After-Tax Net Present Value ("NPV") (8% discount)	$	1,106.9	819.9
Pre-Tax Internal Rate of Return ("IRR")	%	32%	32%
After-Tax Internal Rate of Return ("IRR")	%	27%	27%
Payback Period (After-Tax)	years	3.4	3.4

This preliminary economic assessment is preliminary in nature, includes inferred mineral resources that are considered too speculative geologically to have the economic considerations applied to them that would enable them to be categorized as mineral reserves, and there is no certainty that the preliminary economic assessment will be realized.

1.6 Study Conclusions and Recommendations

1.6.1 Study Conclusions

1. The total Central Clearwater Resource Area Inferred Resource estimate is 5.5 billion m^3 of brine with an average of 74.6 mg/L Li, totaling 2.2 million tonnes of LCE (using a conversion factor of 5.323). This resource could support resource development for at least 20 years as outlined in this Report.
2. The data evaluated indicates that the Leduc aquifer can be proactively managed to efficiently sweep the well network area of lithium; this results in the production of undiluted lithium throughout the evaluated lifetime of the project (greater than 95% original lithium concentration).
3. Similar to oil and gas activity in the area, lithium brine could be efficiently delivered to a central process facility using a well network of strategically positioned producers, injectors and pipelines. Abundant local expertise and infrastructure is available to support this development.
4. Local transmission and distribution infrastructure and natural gas fuel lines are available in the area and are one potential option to support the project's energy requirements.
5. Existing lithium processing and oilfield technologies are combined with E3's Direct Lithium Extraction (DLE) technology to form a full lithium extraction process flow sheet. The successful integration of these technologies as outlined in this Report is reasonably expected.
6. Results of lab testing of E3 Metals' proprietary Direct Lithium Extraction (DLE) technology and the efficient integration of E3's technology with available supporting lithium processing technologies improves the confidence of the estimations contained in this Report.

7. The economic evaluation demonstrates a project NPV of USD 1.1M, an OPEX of USD 3,656/tonne LHM and a pre-tax IRR of 32% at a discount rate of 8%. This positive economic analysis indicates the project has the potential to be economically viable.
8. This preliminary economic assessment is preliminary in nature, includes inferred mineral resources that are considered too speculative geologically to have the economic considerations applied to them that would enable them to be categorized as mineral reserves, and there is no certainty that the preliminary economic assessment will be realized.

1.6.2 Study Recommendations

1. Further geological evaluation of the CCRA, including advanced mapping and aquifer flow testing, are required and should support an upgrade of the resource to the “Indicated” and “Measured” categories (CIM, 2014).
2. Advanced brine and rock property testing, including the analysis of brine samples deeper in the Leduc aquifer, will increase confidence in the proposed pre-treatment and well design estimates.
3. Continued engagement with local transmission service providers, distribution service providers and natural gas fuel suppliers is required to further refine energy solution design and cost estimates, including the development of a GHG reduction strategy.
4. Although the preliminary LHM production flowsheet appears to be technically feasible and robust, confirmation of the sorbent performance and stability as well as the removal efficiency of secondary contaminants through precipitation and subsequent demonstration of the overall process at pilot scale is recommended to optimise the overall process.
5. The results of the planned 2021 pilot plant demonstrating E3’s DLE technology in combination with compatible lithium processing techniques, should be used in further economic evaluations including a Pre-Feasibility Study (PFS).

2 Introduction

2.1 Terms of Reference

E3 Metals Corp, an emerging lithium developer and leading lithium extraction technology innovator, is a public company with a head office located in Calgary, AB. E3 Metals Corp. trades on the Toronto Venture Exchange, as well as the OCT and Frankfurt markets (TSXV: ETMC | FSE: OU7A | OTC: EEMMF). Qualified Persons (Table 2-1) were retained by E3 Metals Corp to prepare a technical report on the Preliminary Economic Assessment of the Clearwater Lithium Project, located in the previously referenced Central Clearwater Resource Area leases, in conformity to National Instrument 43-101 (NI 43-101) standards (the “Report”). This Report has been prepared for E3 Metals Corp. by independent contractors.

2.2 Qualified Persons

The list of Qualified Persons (QPs) for the Technical Report under NI 43-101 Reporting Standards, and the sections for which they are responsible is shown in Table 2-1 below.

Table 2-1. Qualified person by report section

Technical Report Section	Qualified Person	Company
Item 1: Summary	Werner Vorster, P.Eng.	NORAM
Item 2: Introduction	Werner Vorster, P.Eng.	NORAM
Item 3: Reliance on Other Experts	Werner Vorster, P.Eng.	NORAM
Item 4: Property Description and Location	Gordon MacMillan, P.Geol.	Fluid Domains
Item 5: Accessibility, Climate, Local Resources, Infrastructure and Physiography	Gordon MacMillan, P.Geol.	Fluid Domains
Item 6: History	Gordon MacMillan, P.Geol.	Fluid Domains
Item 7: Geological Setting and Mineralization	Gordon MacMillan, P.Geol.	Fluid Domains
Item 8: Deposit Types	Gordon MacMillan, P.Geol.	Fluid Domains
Item 9: Exploration	Gordon MacMillan, P.Geol.	Fluid Domains
Item 10: Drilling	Gordon MacMillan, P.Geol.	Fluid Domains
Item 11: Sample Preparation, Analyses and Security	Gordon MacMillan, P.Geol.	Fluid Domains
Item 12: Data Verification	Gordon MacMillan, P.Geol.	Fluid Domains
Item 13: Mineral Processing and Metallurgical Testing	Werner Vorster, P.Eng.	NORAM
Item 14: Mineral Resource Estimates	Gordon MacMillan, P.Geol.	Fluid Domains
Item 15: Mineral Reserve Estimates	N/A	N/A
Item 16: Mining Methods	Greg Owen, P. Eng.	GLJ Ltd.
Item 17: Recovery Methods	Werner Vorster, P.Eng.	NORAM
Item 18: Project Infrastructure	Scott Pattinson, P.Eng.	SCOVAN Engineering
Item 19: Market Studies and Contracts	Werner Vorster, P.Eng.	NORAM
Item 20: Environmental Studies, Permitting and Social or Community Impact	Greg Owen, P. Eng.	GLJ Ltd.
Item 21: Capital and Operating Costs	Damian Bransby-Williams, P.Eng.	SCOVAN Engineering
Item 22: Economic Analysis	Damian Bransby-Williams, P.Eng.	SCOVAN Engineering
Item 23: Adjacent Properties	Gordon MacMillan, P.Geol.	Fluid Domains
Item 24: Other Relevant Data and Information	Werner Vorster, P.Eng.	NORAM

Technical Report Section	Qualified Person	Company
Item 25: Interpretation and Conclusions	Werner Vorster, P.Eng.	NORAM
Item 26: Recommendations	Werner Vorster, P.Eng.	NORAM
Item 27: References	Werner Vorster, P.Eng.	NORAM

2.3 Sources of Data

The Report is based upon information and data collected by E3 Metals Corp, and data collected, compiled and validated by the authors. Mineral rights and land ownership information was provided by E3 Metals Corp and can be verified at the Government of Alberta[1] website. A portion of the information contained within the Report was derived from the following:

- E3 Metals Corp-supplied maps, logs, laboratory analyses, third-party reports and field sample data;
- Third-party estimates and quotes;
- Test work results from bench scale tests performed on collected brine samples;
- Published literature (see Section 27 for references).

Sources of information are listed in Section 27 and are acknowledged where referenced in the Report text.

[1] https://gis.energy.gov.ab.ca/Geoview/Metallic

2.4 Acronyms

The following table includes acronyms referenced in this Report.

Table 2-2. Reference list of acronyms and definitions

Abbreviation/Term	Description
%	Percent
&	And
"	Inch
°C	Degrees Celsius
°F	Degrees Fahrenheit
AER	Alberta Energy Regulator
AESO	Alberta Energy System Operator
BA	Business Associate
BEV	Battery Electric Vehicle
CAD	Canadian Dollar
CAPEX	Capital Expenditure
CCRA	Central Clearwater Resource Area
CPF	Central Processing Facility
Co.	Company
CO_2	Carbon dioxide
Corp.	Corporation
d	Day
DCF	Discounted Cash Flow
DEA	Diethyl amine
deg	Degrees
DLE	Direct Lithium Extraction
DST	Drill Stem Test
DSU	Drill Spacing Unit
EIA	Environment Impact Assessment
EPEA	Environmental Protection and Enhancement Act
ESP	Electrical Submersible Pumps
et al.	And Others
EV	Electric Vehicle
FEFLOW	Finite Element Subsurface Flow Simulation System
Ft.	Foot
GDP	Gross Domestic Product

Abbreviation/Term	Description
GHG	Green House Gas
h/hr	Hour
H_2S	Hydrogen Sulphide
ha	Hectares
HDPE	High Density Polyethylene
HSE	Health, Safety, and the Environment
Hwy	Highway
ICE	Internal Combustion Engine
Incl.	Inclination
IPR	Inflow Performance Rate
IRR	Internal Rate of Return
IX	Ion Exchange
kg	Kilogram
km	Kilometres
kPa	Kilopascal
kWh	Kilowatt-hour
L	Litre
Lb.	Pound (mass)
LCE	Lithium Carbonate Equivalent
LHM	Lithium Hydroxide Monohydrate ($LiOH.H_2O$)
M	Million
m	Metres
m^3	Cubic Metre
m^3/day	Cubic Metre/Day
Masl	Metres above sea level
mg	Milligrams
MIM	Metallic and Industrial Mineral
ml	Millilitres
mm	Millimeter
MRL	Maximum Rate Limitation
MW	Megawatt
NPS	Nominal Pipe Size
NPV	Net Present Value
OGCR	Oil and Gas Conservation Regulations
OPEX	Operating Expenditure

Abbreviation/Term	Description
Pa	Pascal
PEA	Preliminary Economic Assessment
Pop.	Population
ppm	Parts per million
QA	Quality Assurance
QP	Qualified Person
RO	Reverse Osmosis
s	Second
SOP	Standard Operating Procedure
t	Tonnes
TM	Trademark
TSX	Toronto Stock Exchange
TVD	True Vertical Depth
USD	United States Dollar
UWI	Unique Well Identifier
yrs	Years

3 Reliance on Other Experts

NORAM's preliminary design of the processing facility (described in Section 17) is based on data provided by E3 Metals Corp. of the test work conducted by GreenCentre Canada as described in Section 13. NORAM did not independently verify or audit the test work results or laboratory. Similarly, NORAM has not conducted an independent review or audit of the market studies, contracts and studies but relied on information readily available in open-source literature.

With respect to the discussion in Section 20 (Environmental Studies, Permitting and Social or Community Impact), the QP is familiar with the regulations discussed as they apply in an oil and gas development context. However, the QP relied on E3 Metals Corp. for an interpretation of the various legislation with respect to how they relate to lithium development.

For information on taxes and royalties, QPs relied on E3 Metals Corp. for interpretation of the Metallic and Industrial Minerals Royalty Regulation and the inclusion of applicable Federal and Provincial taxes in the financial model.

4 Property Description and Location

4.1 Location

E3 Metals Corp.'s Alberta Lithium Project is located in south-central Alberta between Edmonton to the north and Calgary to the south (Figure 4-1). The project overlies the Leduc Reef, an oil producer and source of lithium brines.

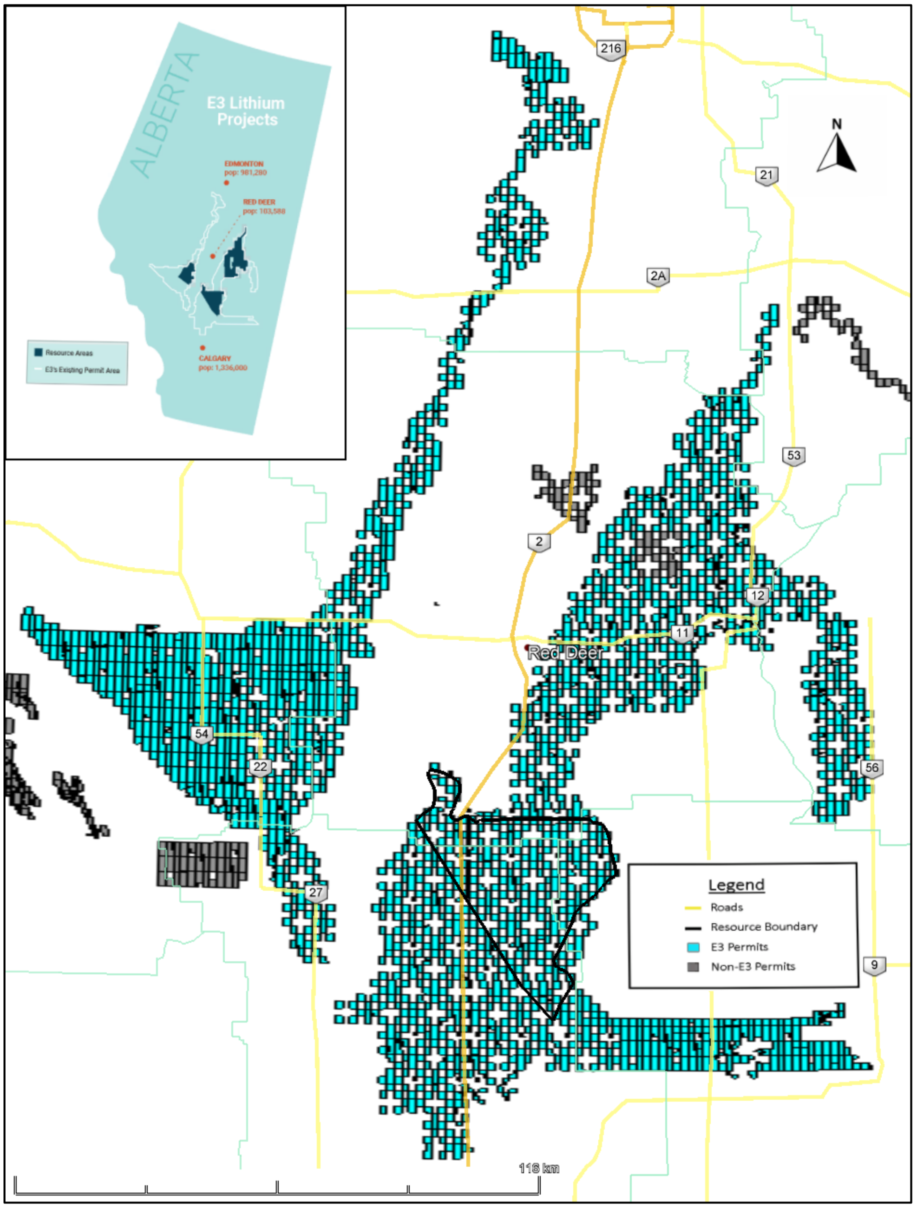

Figure 4-1. Location of Alberta Lithium Project in south-central Alberta (E3 Metals, 2020)

4.2 Property Description

The Alberta Lithium Project consists of 80 Metallic and Industrial Mineral Permits (the Permit Area) that cover the Leduc aquifer in Southern Alberta (Figure 4-2). All permits are held 100% by 1975293 Alberta Ltd (Alberta Co), a wholly owned subsidiary of E3 Metals Corp. The property is subdivided into 6 Sub-Project areas (Table 4-1) outlined on Figure 4-2 and the areas of the resource study are summarized in Appendix A. The total area of the permits is 600,332.9 hectares.

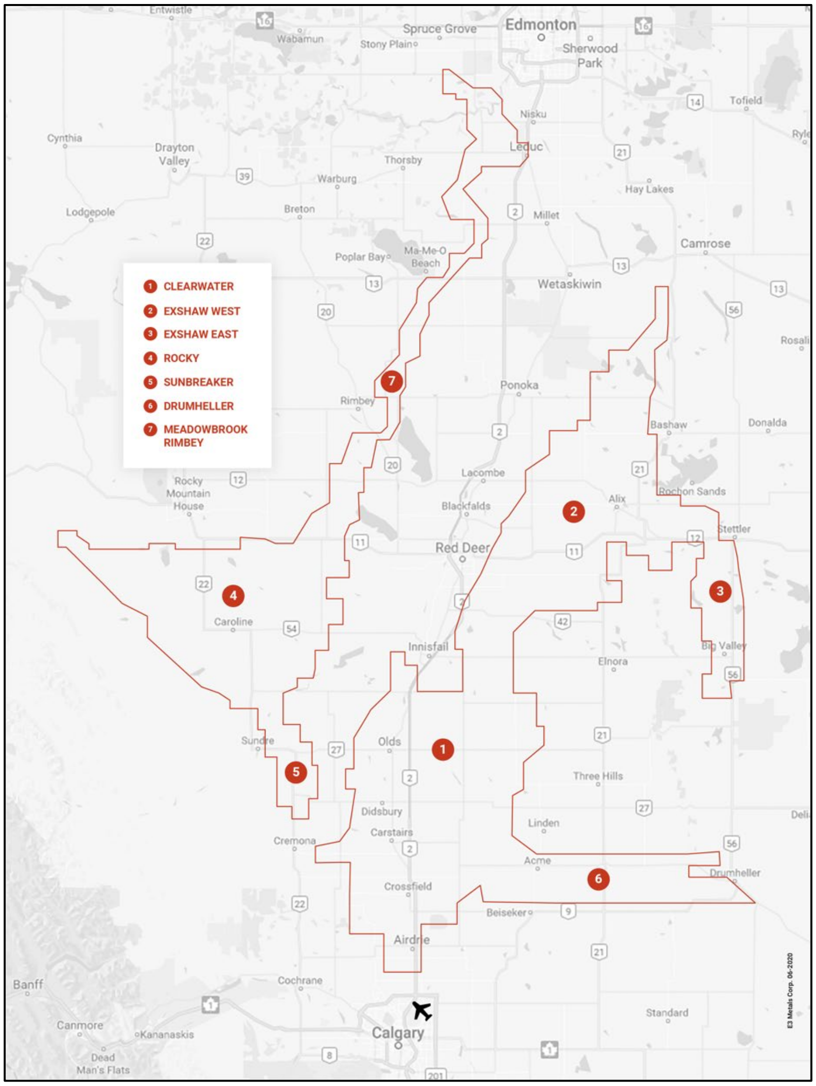

Figure 4-2. Location of Alberta Lithium Project Permits (E3 Metals, 2020)

The Clearwater Area, a sub-area of the Tract 3 Clearwater claims in Table 4-1, consists of 157,305 hectares covered in 21 Metallic and Industrial Mineral (MIM) Permits. Of the 21 permits, 13 permits completely or partially intersect the CCRA boundary, with 50,464 ha falling within the CCRA boundary. The claims are interspersed with privately owned (Freehold) land.

Table 4-1. Summary of the Alberta Lithium Project lease holdings (E3 Metals, 2020).

Area	Total Ha	# of Permits
Rocky	184,022	24
Sunbreaker	15,678	2
Clearwater	157,305	21
Exshaw	142,285	18
Drumheller	55,511	8
Meadowbrook Rimbey	45,532	7
Total	600,333	80

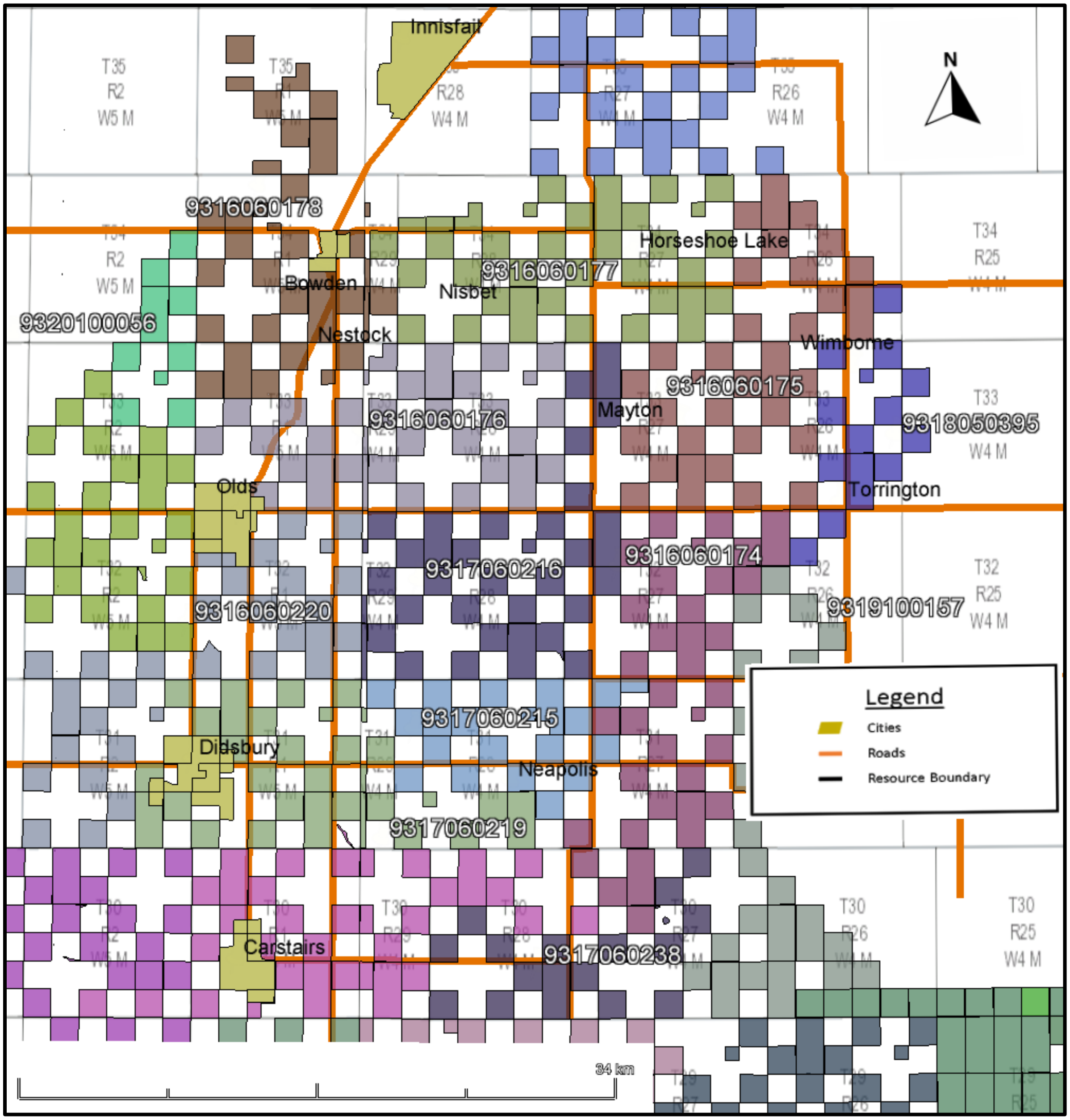

Figure 4-3. Location of Central Clearwater Resource Area and permits held within the Alberta Lithium Project, Alberta, Canada (E3 Metals, 2020). The center of the permit holdings is at 51.83 N 113.83 E in the NAD83 datum.

Alberta Metallic and Industrial Mineral Permits grant the explorer the exclusive right to explore for metallic and industrial minerals for seven consecutive two-year terms (total of fourteen years), subject to traditional biannual assessment work. Work requirements for maintenance of permits in good standing are CAD 5.00/ha for the first two-year term, CAD 10.00/ha for each of the second and third terms, and CAD 15.00/ha for each the fourth, fifth, sixth and seventh terms.

The statutes also provide for conversion of Permits to Metallic Minerals Leases once a mineral deposit has been identified. Leases are granted for a renewable term of 15 years and require annual payments of CAD 3.50/ha for rent to maintain them in good standing. There are no work requirements for the maintenance of leases and they confer rights to minerals. Complete terms and conditions for mineral exploration permitting and work can be found in the Alberta Mines and Minerals Act and Regulations (Metallic and Industrial Minerals Tenure Regulation 145/2005, Metallic and Industrial Minerals Exploration Regulation 213/98). These and other acts and regulations, with respect to mineral exploration and mining, can be found in the Laws Online section of the Government of Alberta Queen's Printer website[2].

The mineral permits are interspersed with privately owned (Freehold) land, where the surface and/or minerals rights are owned by private individuals and/or companies and not the crown (the white areas interspersed within the E3 Metals Permit Area in Figure 4-2). The Freehold lands do not pose an obstacle to brine assay and mineral processing test work within the mineral permits owned by E3 Metals. Given a favorable distribution of contiguous Permit coverage and completion of advanced characterization studies focused on the drawdown effect of the liquid resource (particularly laterally), it is possible that E3 Metals does not have to acquire Freehold Land in order to produce Li-brine from aquifers within the properties.

The inferred resource estimate outlined within this Report has been completed on the central portion of the Clearwater Property (See Figure 4-3). The Central Clearwater Resource Area (CCRA) consists of 102,800 ha across 13 Metallic and Industrial Mineral (MIM) Permits that completely or partially intersect the CCRA. The 13 MIM permits have a total of 92,225 ha with a second 2-year in-ground expenditure commitment of CAD 855,048 (Appendix Table A-1).

4.3 Property Royalties

On September 24, 2020, the Company signed a Royalty Agreement pursuant to which it has agreed to pay to the royalty owner a perpetual production royalty equal to 2.25% (the "Royalty") of the gross proceeds from all products that are mined or extracted from eight specific Clearwater MIM permits.

The Company has the option, at any time before September 30, 2022, to purchase all or a portion of the royalty at a price of:

- CAD 800,000 for the entire 2.25% of the Royalty, or
- CAD 100,000 for each 0.25% of the Royalty, provided that the maximum amount to purchase the entire 2.25% of the Royalty will be CAD 800,000.

[2] https://www.alberta.ca/minerals-acts-and-regulations.aspx

The permit numbers are 9316060174, 9316060175, 9316060176, 9316060177, 9316060178, 9316060179, 9320100056 and 9319110154. For the purposes of this Report, it has been assumed the Company will purchase this royalty prior to September 30, 2022.

4.4 Environmental Issues

At the current stage of the project, there are no environmental liabilities to E3 Metals. Environmental considerations and permitting for this project at a later stage are outlined in Section 20.

5 Accessibility, Climate, Local Resources, Infrastructure and Physiography

5.1 Accessibility

The Clearwater property is readily accessible by air and ground transportation (Figure 5-1). There are international airports in Calgary (YYC) and Edmonton (YEG). Red Deer hosts a regional airport (YQF).

Major and secondary provincial highways, and all-weather roads developed to support oil/gas infrastructure, occur throughout the permit areas. The City of Red Deer (population of 101,002) is located at the junction of Alberta Provincial Highway 2 (“Hwy 2”) and Highway 11; Hwy 2 is the main corridor between Edmonton and Calgary and runs North-South directly through the Clearwater Property. Further access to the properties is provided by secondary one- or two-lane all-weather roads, and numerous all weather and dry weather gravel roads. The resource area can be accessed year-round, ensuring mineral test work and extraction is not limited to certain months of the year. Two rail lines (Canadian Pacific Railway and the Canadian National Railway) are present throughout the area and connect to the major centers of Edmonton and Calgary which occur north and south of the resource area and then all of North America.

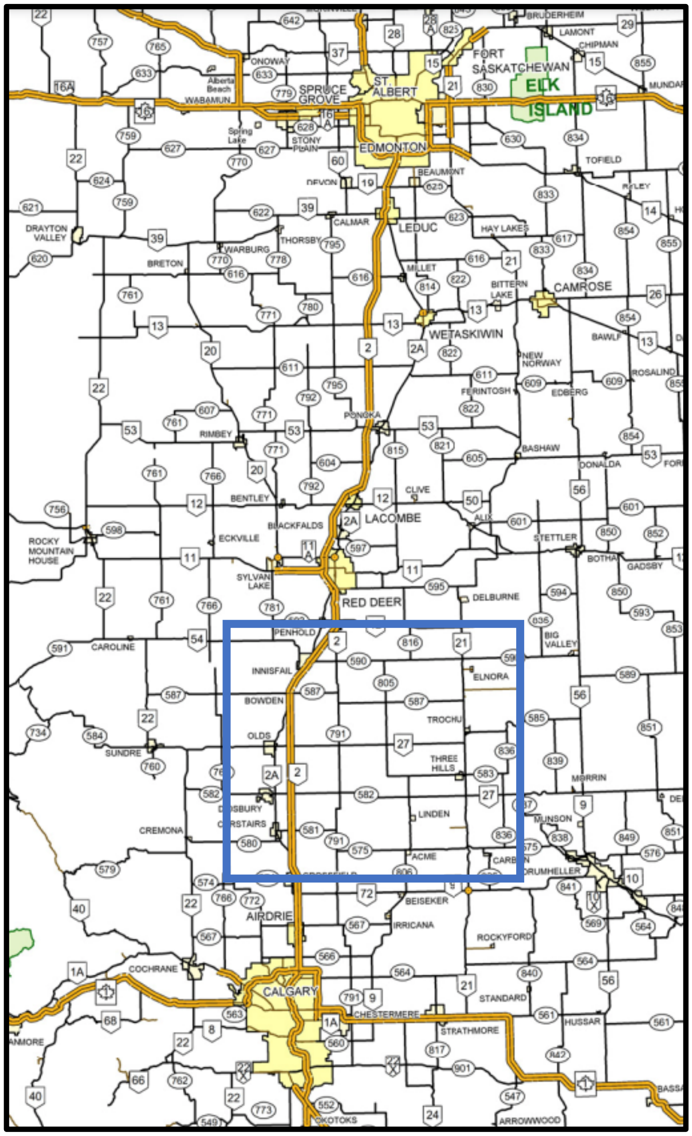

Figure 5-1. Primary roads, secondary roads and air access to Project area[3] (blue rectangle)

[3] http://www.transportation.alberta.ca/Content/docType329/Production/11x17_Provincial_Network_Map.pdf

5.2 Climate

Calgary, Alberta has a humid continental climate with severe winters, no dry season, warm summers and strong seasonality (Köppen-Geiger classification: Dfb).

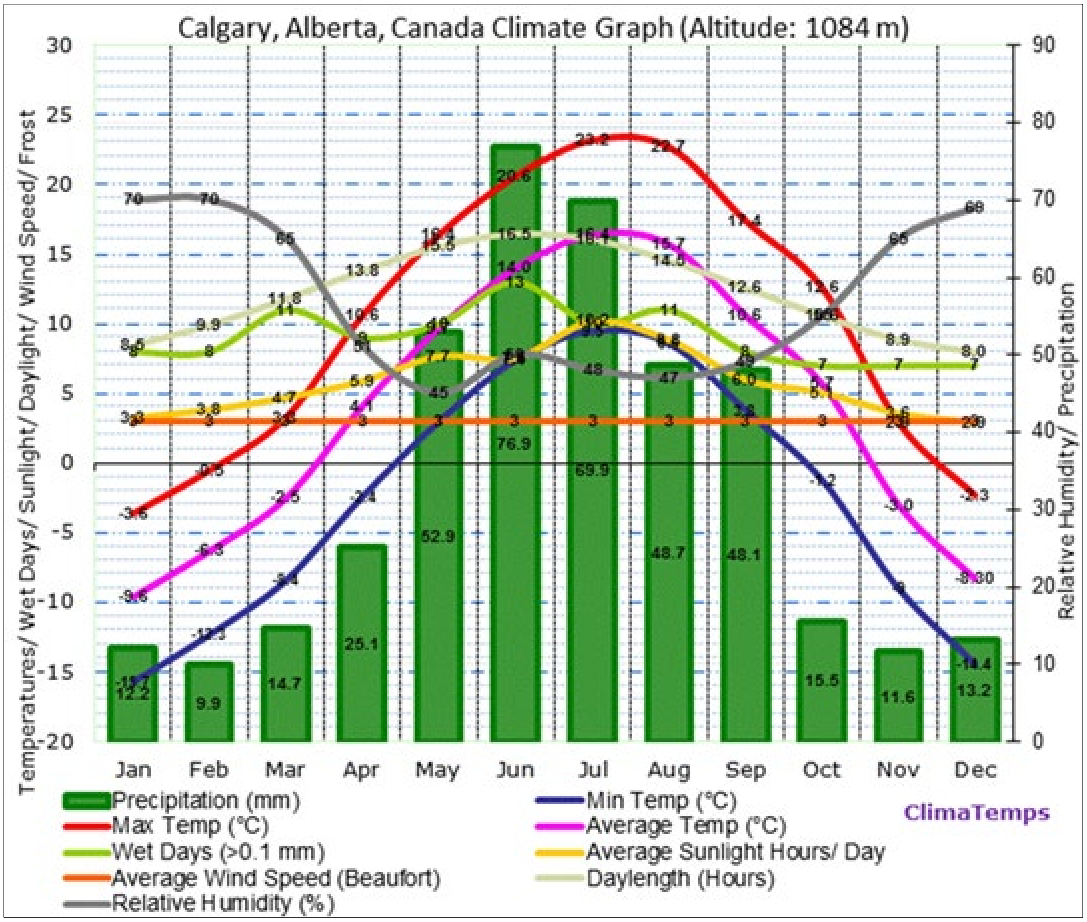

Figure 5-2. Summary of monthly annual climate data for Calgary, AB[4].

[4] http://www.calgary.climatemps.com/

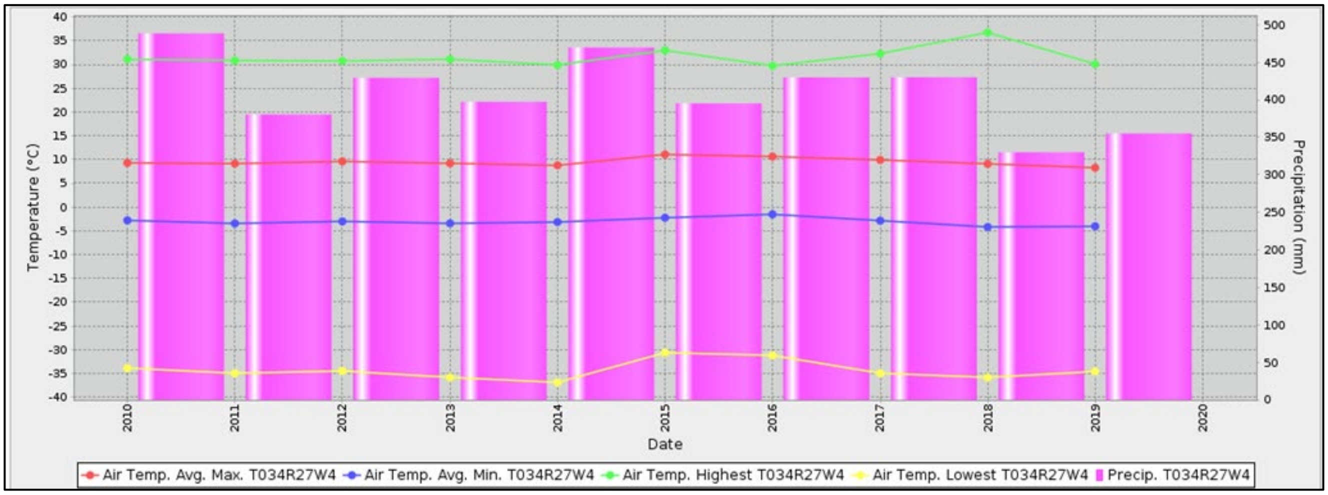

Figure 5-3. 10-year temperature and precipitation ranges for T34N R28W, the center of the Clearwater claims (ACIS, 2020).

During summer, average daily high temperatures are 22.8°C (73.0 °F) and average daily low temperatures are 8.2°C (46.8°F). Winter temperatures have average daily highs of -3.3°C (26.1°F) during the day and average daily lows of -14.1°C (6.6°F) generally shortly after sunrise. Total annual precipitation averages 397.9 mm (15.7 inches). A summary of Calgary climate data by month is shown in Figure 5-2. A 10-year summary of high-low-mean air temperature and mean precipitation for township 34, range 28 W4M, the center of the Clearwater claims, is shown in Figure 5-3.

5.3 Local Resources

Accommodation, food, fuel, and supplies are readily obtained in the City of Red Deer (pop. 101,002 (2019)) 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. Service companies, including those providing wireline services, testing, workovers and drilling, all operate locally and will be capable of meeting the company's needs relating to drilling, production and construction.

5.4 Infrastructure

There is a significant amount of infrastructure in the area to support over 70 years of oil and gas development operations. Oil and gas are typically produced in the area using pump jacks. 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 into 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 disposal and/or injection purposes. These water pipeline networks are specifically located in areas developed for oil and gas.

Main highways are properly maintained and upgraded, and secondary gravel roads are well maintained. Grid electrical distribution and transmission infrastructure is available throughout the resource area and many of the locations sampled for this resource have power accessible directly at the lease. There is adequate land in the area for process plants and related future infrastructure.

5.5 Physiography

The project area lies within the Southern Alberta uplands and Western Alberta plains (Figure 4-1). The dominant landform is undulating glacial till plains, with about 30 percent 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. The Red Deer River is the dominant topographic feature; it runs northwards and is situated between the Exshaw East and Exshaw West sub properties. The region is dominantly farmland with numerous creeks and wetlands occurring throughout the property. Clusters of forested terrain are dominated by aspen, balsam poplar, lodge pole pine and white spruce. Vegetation in the wetland areas is characterized by black spruce, tamarack and mosses. The area is generally composed of farmland and prairie grasses.

6 History

In the Permit area, there have been no drilling exploration programs to target lithium enriched brine specifically. Historical testing of lithium in water, prior to E3 Metals, was conducted as part of routine chemistry analysis by oil and gas operators in the area. This data was compiled in a comprehensive overview of the mineral potential of formation waters from across Alberta by the Government of Alberta (Hitchon et al., 1993, 1995). Subsequent collection of brine water from actively producing oil and gas wells was conducted by the AGS by Eccles and Jean (2010) 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 below.

6.1 Oil and Gas Drilling History

Existing wells in this area were drilled for petroleum and natural gas. Early operators for oil and gas fields in the area included such companies as Husky Oil & Refining Ltd, Shell Oil Company of Canada, Hudson's Bay Oil & Gas Co., and British American Oil Co. Ltd. (Gulf Canada). These companies were active in the resource areas as early as 1951 and some remain active to date.

The Leduc #1 well, drilled by Imperial Oil, was one of the first oil wells in Alberta drilled into the Late Devonian Leduc formation in 1947. Some of the most prolific formations produced historically are the Devonian formations, which includes the Beaverhill Lake Group and the Swan Hills, Leduc, Nisku, and

Wabuman formations. The Leduc reefs were a prevalent target for hydrocarbons from the mid to late 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 unconventional oil aquifers such as the Duvernay Formation. A significant volume of petroleum-related fluid 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 and the underlying Cooking Lake Formation that is of significance with respect to this assessment for mineral brine potential in the CCRA.

The CCRA contains two major Leduc oil pools of note, namely the Innisfail oil field on the western edge, discovered in 1956 by Canadian Oils Ltd., and the Wimborne field on the eastern edge, discovered by Seaboard Oil Company in 1954. These two pools form the eastern and western defining edges of the resource area and roughly correspond to the Leduc Platform Margin. A total of 1,846 wells have been drilled within the CCRA, 158 wells have intercepted the Leduc Formation. A total of 152 wells are classified as having produced, currently producing or injecting into the Leduc Formation.

6.2 Well Logs

Open hole wireline logging technology is an effective method for evaluating reservoir properties. Wireline 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. Interpretations from well logs are used in the aquifer model discussed in Section 14.

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

The well logs available in the area are as follows:

- Gamma Ray Log: measures the radioactivity of rocks and helps determine lithology[5]
- Induction Log: measures rock conductivity, and helps determine lithology and fluid composition[6]
- Density and Neutron logs: measures hydrogen concentration and electron density[7], and helps determine lithology and pore space in the rock

[5] http://petrowiki.org/Gamma_ray_logs, 2017
[6] http://petrowiki.org/PEH:Resistivity_and_SP_Logging, 2017; Archie, 1942
[7] American Association of Petroleum Geologists, 2017

- Photoelectric logs: measures atomic weight of the rocks, and helps determine lithology

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 and aquifer parameters within the Leduc and Cooking Lake aquifers.

6.3 Drill Stem Tests

A Drill Stem Test (DST) is an oilfield test that isolates a particular range of depths in a wellbore to measure the aquifer pressure, permeability (ability to flow fluid) and fluid types present at specified depths. DSTs have been run in the vicinity of the resource areas since the 1950's. Data collected during DSTs are compiled by the Government of Alberta and were accessed through third party software (GeoSCOUT 2017). DST data was reviewed to determine aquifer pressure and permeability in the resource areas.

Prior to adopting DST-derived pressure estimates as representative of the aquifer, a quality assurance (QA) program was followed that eliminated suspect or erroneous data. After completing the QA program, a pressure data set of 327 DSTs with extrapolated pressure measurements was identified in E3's Rocky, Clearwater, and Exshaw permit area. The resulting data set consisted of 324 pressure measurements in the Leduc Formation and 3 pressure measurements in the Cooking Lake Formation.

Within the CCRA there were 33 DST pressure measurements considered representative of the aquifer pressure. 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 aquifer pressure and to contribute to the characterization of the hydraulic continuity of the aquifer.

6.4 Production, Injection and Disposal

Historical production volumes for the Cooking Lake and Leduc formations were exported from Divestco's GeoCarta software (Divestco 2020). The reported production was queried for the CCRA and a buffer area around the CCRA, in order to include production from outside of the resource area that may directly affect pressures in the CCRA.

The CCRA, historical production query, included Townships 30 to 35 and Ranges 1W5M to 26 W4M. A total of 200 wells in, or in close proximity to, the CCRA had at least one month of reported water production. The maximum monthly water production rates were as high as 1,300 m^3/d (100/10-35-033-26W4M). Within the resource area, most of the production was in the Wimborne Margin and the Innisfail Margin areas. The first year of reported production was 1961 and the last month of production data summarized below is August 2020. Reported production in the CCRA was nearly all from the Leduc Formation although some wells were comingled with other zones.

Total reported fluid volumes in the CCRA are:

- 13,589,397 x 10^3 m^3 of gas produced;
- 102,254 m^3 of condensate produced;
- 19,101,770 m^3 of oil produced;
- 60,103,636 m^3 of water produced; and
- 61,612,806 m^3 of water injected.

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 increased considerably since the 1970s and peaked in 2007 when 2,615,456 m^3 of water was produced. As expected, since production in this field began in the 1960s the injected water volumes correlate closely with the produced water volumes. This correlation supports the interpretation that the produced and injected water volumes are associated with water flood of the aquifer to enhance the production of hydrocarbons.

6.5 Historical Lithium Data

Section 6.5 was extracted from Eccles (2017) technical report prepared for E3 Metals.

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 and if the rock is permeable (has the capacity to flow fluids through it) it could represent an aquifer. Hitchon et al. (1993, 1995) compiled nearly 130,000 analyses of formation water from various stratigraphic ages across Alberta. The data was derived from numerous sources including Alberta Energy Regulator (“AER”) submissions for drilling conducted by the petroleum industry and various Government of Alberta reports (e.g., Hitchon et al., 1971; 1989; Connolly et al., 1990a, b and unpublished analytical data collected by the Government of Alberta).

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 Li was considered to be 50 ppm and the detailed exploration threshold value was defined as 75 ppm (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 Li concentrations above the ‘regional threshold value’ (greater than 50 ppm); and 47 analyses yielded Li concentrations above the ‘detailed threshold value’ of 75 ppm. Significantly, Hitchon et al. (1993, 1995) showed the highest concentrations of Li in formation water – up to 140 mg/L Li – occurred within Middle to Late Devonian aquifers associated with the Beaverhill Lake Group (Swan Hills Formation), Woodbend Group (Leduc Formation), Winterburn Group (Nisku Formation) and Wabamun Formation aquifers.

More recently, Eccles and Jean (2010) modelled 1,511 lithium-bearing formation water analyses from throughout Alberta; this compilation supported the previous government author's conclusions that aquifers associated with Devonian strata comprise elevated concentrations of lithium in reef systems throughout Alberta. Of the 1,511 analyses, 19 analyses/wells contained >100 mg/L Li (up to 140 mg/L), all of which were sampled from within the Middle to Late Devonian carbonate complexes.

7 Geological Setting and Mineralization

7.1 Geological Setting

The E3 Metals Resource Areas are located in the southwestern part of the Western Canada Sedimentary Basin (WCSB). In this area, the Upper Devonian (Frasnian) sediments of the Woodbend Group were deposited in a shallow 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). It is here that the flooded carbonate platform of the Cooking Lake provided relative structural highs and a favorable environment for the growth of the prolific reefal buildups of the Leduc Formation.

The Clearwater area covers a portion of the Wimborne-Bashaw complex to the east of the Meadowbrook Rimbey trend. The basinal shales and carbonate muds of the Duvernay and Ireton conformably encase and overlay the Leduc buildups, creating traps for hydrocarbon pools. These low-permeability shales also form the aquitard, a formation of much lower water permeability than an aquifer, for the Leduc and Cooking Lake aquifer systems.

The Leduc and Cooking Lake limestone deposits were, at some post burial stage, partially to completely replaced by dolomite. 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 (American Association of Petroleum Geologists, 2017). Dolomite crystals are larger than limestone, and larger crystals typically improve permeability (Lucia, 1995).

There are many possible mechanisms theorized as to the source of dolomitizing Mg-rich fluids and the method for their transport into the Leduc system (Atchley et al. 2006; Amthor et al., 1993; Machel et. al., 2002). Dolomitization of the Leduc and Cooking Lake in this area generally enhances the porosity and permeability of the aquifer, except in some localized cases where secondary cementation has occurred to reduce the porosity.

The Leduc and Cooking Lake aquifer system contains lithium-enriched brine associated with reefal carbonates of the Woodbend and Winterburn Group (Hitchon et. al., 1995; Eccles and Jean, 2010). Speculation exists as to the source of the lithium, but the source is ultimately unknown (Eccles et. al, 2012). For the Leduc and Nisku system in southern Alberta, Huff (2016) proposed a source involving lithium concentrated Devonian evaporates to the west and upward movement of Li-enriched brine into the Leduc and Nisku carbonates during later mountain building.

Formation water is currently being produced as a waste by-product associated with petroleum and natural gas from existing wells. Pressure loss in the aquifer 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.

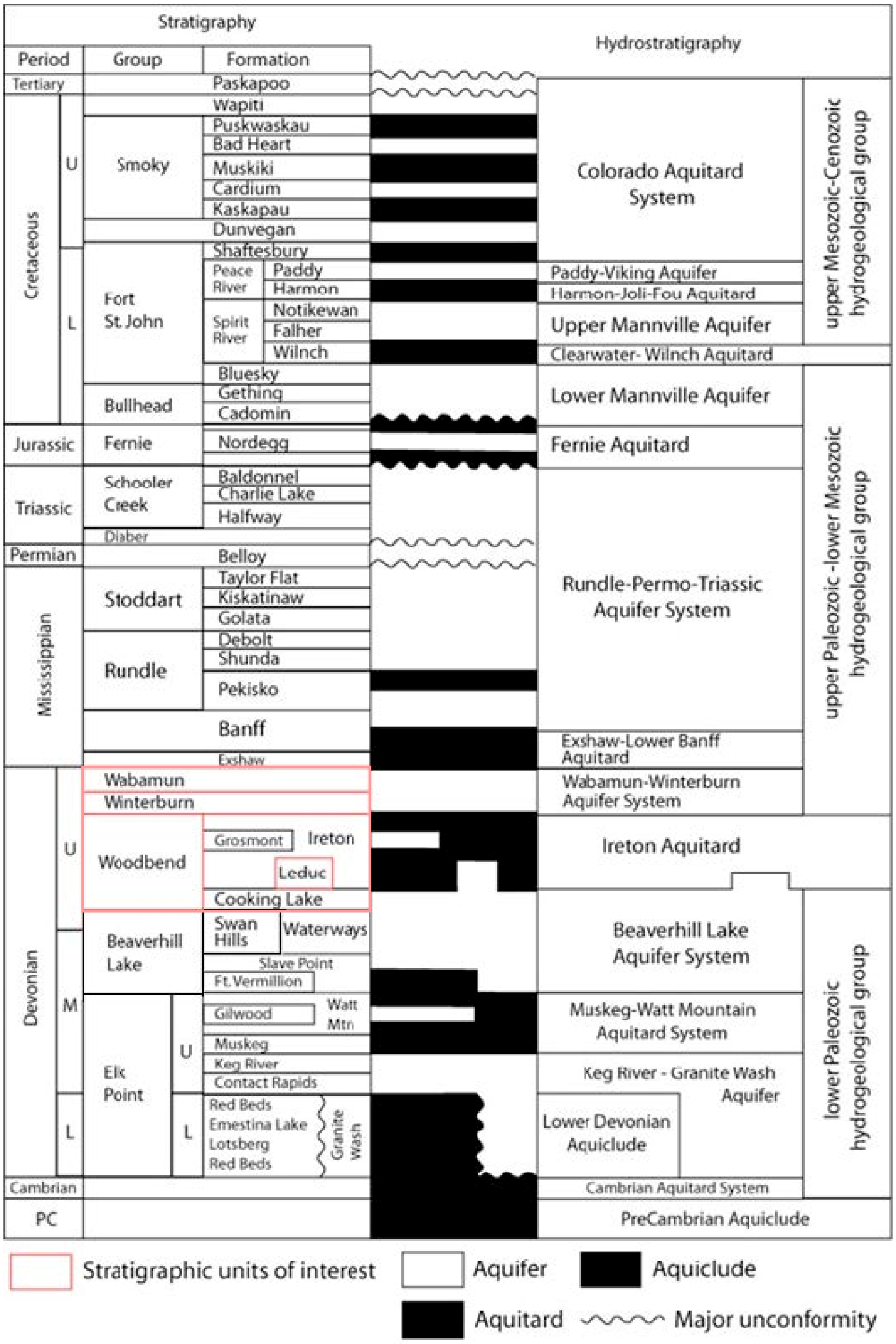

Figure 7-1. Regional stratigraphy/hydrostratigraphy of Alberta(adapted from Hitchon et al., 1990). The stratigraphic units of interest are denoted in red.

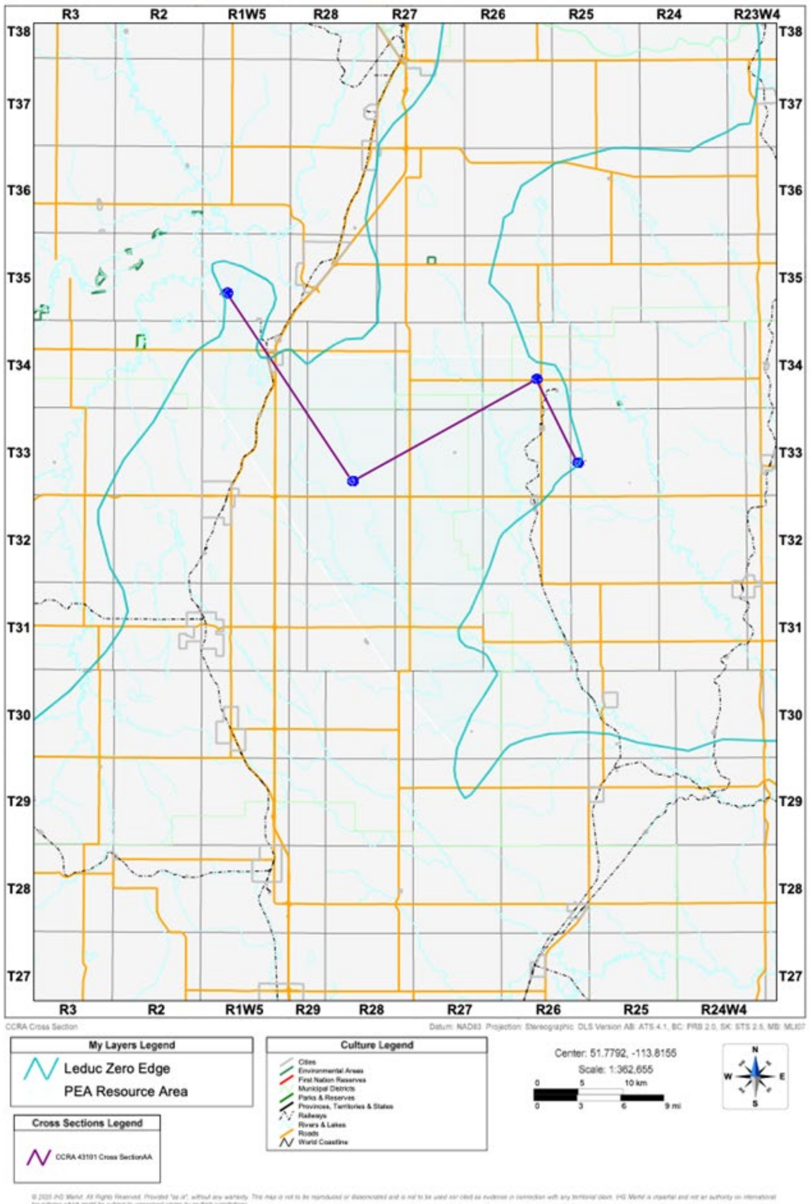

Figure 7-2. Area map (Accumap™) showing the regional Leduc edge (blue) and cross section reference line (burgundy) for Figure 7-3 and Figure 7-4 (E3 Metals Corp, 2020).

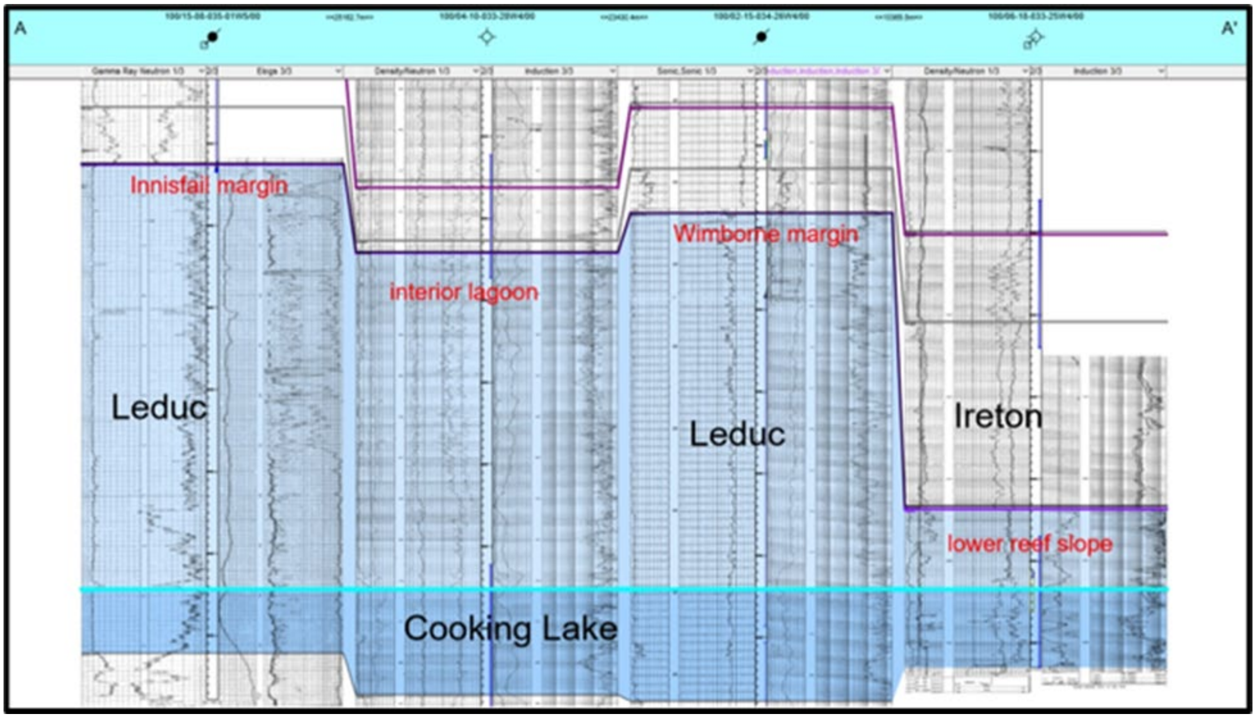

Figure 7-3. Geological stratigraphic cross section of the CCRA, line A-A' (Figure 7-2) using a Cooking Lake Datum (E3 Metals Corp. using GeoLOGIC Systems). This cross section demonstrates the aquifer continuity across the Clearwater area Leduc platform. It highlights the relative thickness of the Leduc reef margins at Innisfail and Wimborne to the thinner interior platform lagoon and the lower reef slope towards the basin on the east side.

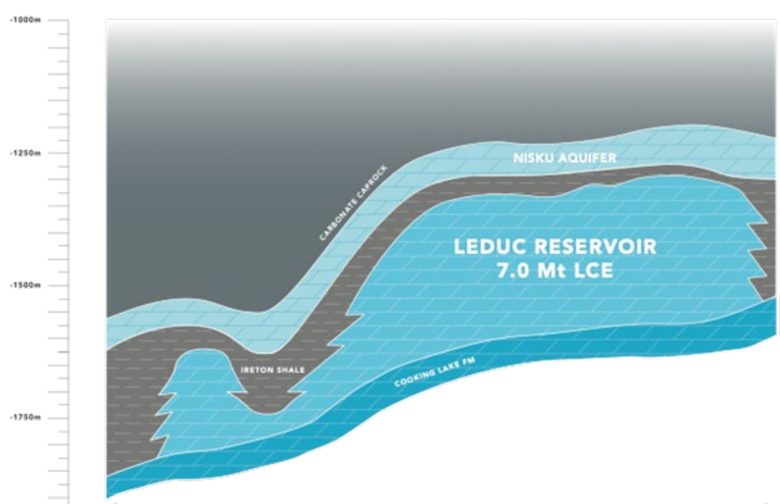

Figure 7-4. Schematic representation of the CCRA (to scale with vertical exaggeration) highlighting the current relationships of the geology, structure, and hydrocarbon pools. (E3 Metals, 2020)

7.2 Precambrian Basement

Section 7.2 was modified from E3 Metals Technical Report (Eccles, 2017).

The Clearwater property lies in the southern portion of the WCSB, which forms a wedge of Phanerozoic strata overlying the Precambrian basement. The basement underlying the Clearwater property is predominantly Lacombe Domain with the southeastern portion of the property on the Hearn Terrane (Pană, 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, 1998).

7.3 Phanerozoic Strata

Section 7.3 was modified from E3 Metals Technical Report (Eccles, 2017).

A thick sequence of Tertiary and Cretaceous clastic rocks and Mississippian to Devonian carbonate, sandstone and salt overlie the basement (e.g., Green et al., 1970; Glass, 1990; Mossop and Shetsen, 1994). At the base of the Beaverhill Lake Group, the Elk Point Group is comprised of restricted marine carbonate and evaporite that gradationally overlies the Watt Mountain Formation (Mossop and Shetsen, 1994). The Upper Elk Point, including the Ft. Vermillion, Muskeg and Watt Mountain formations represent an aquitard layer (Figure 7-1; Hitchon et al., 1990).

The Upper Devonian Woodbend Group conformably overlies the Beaverhill Lake Group (Figure 7-1). The Woodbend Group is dominated by basin siltstone, shale and carbonate of the Majeau Lake, Cooking Lake, Duvernay and Ireton formations, which surround and cap the Leduc reef complexes. The Leduc reefs are characterized by multiple cycles of reef growth including backstepping reef complexes and isolated reefs (Mossop and Shetsen, 1994). The Leduc Formation (Woodbend Group) is the major host to prolific reserves of oil and gas in Alberta and contains elevated concentrations of Li (Hitchon et al., 1995). 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 formed by an extremely voluminous influx of shale into the region (Mossop and Shetsen, 1994). The Ireton Formation is an aquitard 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 (Figure 7-1). In the area of the E3 Metals properties, 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. The Wabamun Group is composed of buff to brown massive limestone interbedded with finely crystalline dolomite at the base. These two Groups comprise the Wabamun-

Winterburn aquifer system from which a few anomalous Li analyses have been obtained (Hitchon et al., 1995).

The Wabamun Group is unconformably overlain by the Lower Carboniferous Exshaw shale, an aquitard. The Exshaw shale is overlain by the Banff Group, which is composed of a medium to light olive grey limestone with subordinate fine-grained siliciclastics, marlstone and dolostone overlying a basal shale, siltstone and sandstone unit (Mossop and Shetsen, 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 is composed of shelf sand and carbonate (Mossop and Shetsen, 1994).

The overlying Mesozoic strata (mainly Cretaceous) are composed of alternating units of marine and nonmarine sandstone, shale, siltstone and mudstone. The Triassic includes fine-grained argillaceous siltstone and sandstone. The overlying Jurassic Fernie Group is composed of limestone of the Nordegg Formation that is overlain by interbedded sandstone, siltstone and shale (Mossop and Shetsen, 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 (Figure 7-1).

Bedrock units underlying the Resource Areas include the late Cretaceous Horseshoe Canyon and Scollard formations and Tertiary Paskapoo Formation (Figure 7-1). Horseshoe Canyon 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 are economically significant, particularly in western Alberta. Finally, the Paskapoo Formation underlies the CCRA, and much of southwestern Alberta. It consists of sandstone, siltstone and mudstone.

7.4 Quaternary Geology

Section 7.4 was modified from E3 Metals' Technical Report (Eccles 2017).

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 CCRA is covered by drift of variable thickness, ranging from a discontinuous veneer to just over 15 m (Pawlowicz and Fenton, 1995a, b). 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 compilations (Mossop and Shetsen, 1994; Pawlowicz and Fenton, 1995a, b). Glacial ice is believed to have receded from the area between 15,000 and 10,000 years ago.

7.5 Structural History

Section 7.5 was modified from E3 Metals Technical Report (Eccles 2017).

The Clearwater permits are situated northeast of the Rocky Mountains. An extensive study by Edwards et. al. (1998) utilizing aeromagnetic data, gravity data, and lineament analysis indicates that 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.

There are numerous reef complexes in the Clearwater properties (e.g., Bashaw, Innisfail, Medicine River – Woodbend Group; Nisku carbonate bank–Winterburn Group). These reef complexes promoted growth over long periods of time, and in the permit areas reach thicknesses of 300 m in places. In such places, thick Leduc buildups are prominent structural features in the stratigraphic column.

7.6 Mineralization

Section 7.6 was modified from E3 Metals' Technical Report (Eccles 2017).

The potential for lithium-enriched brine in the Devonian petroleum system of Alberta was initially identified by Hitchon et al. (1995). Potential aquifers 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) confirmed the presence of elevated Li (e.g., >75 mg/L Li) in aquifers associated with the Devonian reef complexes.

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

Li-brine wastewater is associated with oil and gas production. The Devonian petroleum system region represents a mature petroleum field and today, most, if not all of the wells produce far more water than petroleum products. Many of the wells in this area in their early history started out at hundreds to thousands of barrels per day of petroleum products and required little active pumping to extract. However, at present most of the wells produce excessive amounts of formation water in comparison to petroleum products. Formation water production in the CCRA averaged approximately 1,600 m^3/day over the last 5 years (Accumap™, 2020).

8 Deposit Types

Lithium brine deposits are accumulations of saline groundwater that are enriched in dissolved lithium and other elements. All presently producing lithium brine deposits are referred to as salars and share a number of first-order characteristics: (1) arid climate; (2) closed basin contained in a playa or salar; (3) tectonically driven subsidence; (4) associated igneous or geothermal activity; (5) suitable lithium source-rocks; (6) one or more adequate aquifers; and (7) sufficient time to concentrate a brine (Bradley et al., 2013). However, 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 Li-isotope and elemental data from Li-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 Li-brine in the Nisku and Leduc formations are 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 (2000) proposes these deep basinal brines migrated from the Prairie Evaporite into regional aquifers 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 Bashaw and Meadowbrook Rimbey, would suggest the lithium is potentially sourced from the later Devonian Nisku sea.

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; 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 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.

9 Exploration

Hydrocarbon production by oil and gas operators in E3 Metals' permit area is very often associated with co-produced brine water from the formation. Significant volumes of hydrocarbons and brine have been produced from the Leduc aquifer across the Resource Area since the 1960's, and this has resulted in a rich database of aquifer (reservoir) and production data. Over time, the relative amount of water produced from the Leduc has increased in comparison to hydrocarbons. Water in some cases represents an excess of 98% of the total volume arriving at surface. Various oil and gas operators have allowed E3 Metals access to oil and gas infrastructure for brine collection across the permit areas and this has enabled E3 Metals to execute an exploration program without the costly requirement of drilling a well.

9.1 Sample Wells

Exploration activities undertaken other than the sampling program (Section 9.2) included a full geological and hydrological review of the Leduc aquifer and formation water sampling from existing oil and gas production wells. Samples were collected for E3 Metals from existing Leduc Formation producing oil and gas wells by field crews contracted from Maxxam Analytics and AGAT Laboratories in Red Deer, Alberta. Wells were selected based on their status as an active Leduc producer, without any additional concurrent zone production (commingling), and their availability. Oil and gas operators generally cycle wells, so it was necessary to complete several field programs to collect the samples.

9.2 Field Sampling

Samples were either collected directly at the wellhead, or at test separators. Where sampling was conducted at the wellhead, a 4L 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 4L bottle and into a 1L opaque amber glass bottle. See Figure 9-1 below.

Samples were also collected at test separators. Test separators are used in the oil field 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, whereas 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 company ensured that the wells used went "into test" at least 24 hours prior to sample collection to flush the lines and ensure no risk of contamination from other wells.

Figure 9-1. Sample collection at wellhead. Left: Maxxam employee sampling from access port into 4 L plastic container. Right: Decanting brine sample from bottom of 4 L container.

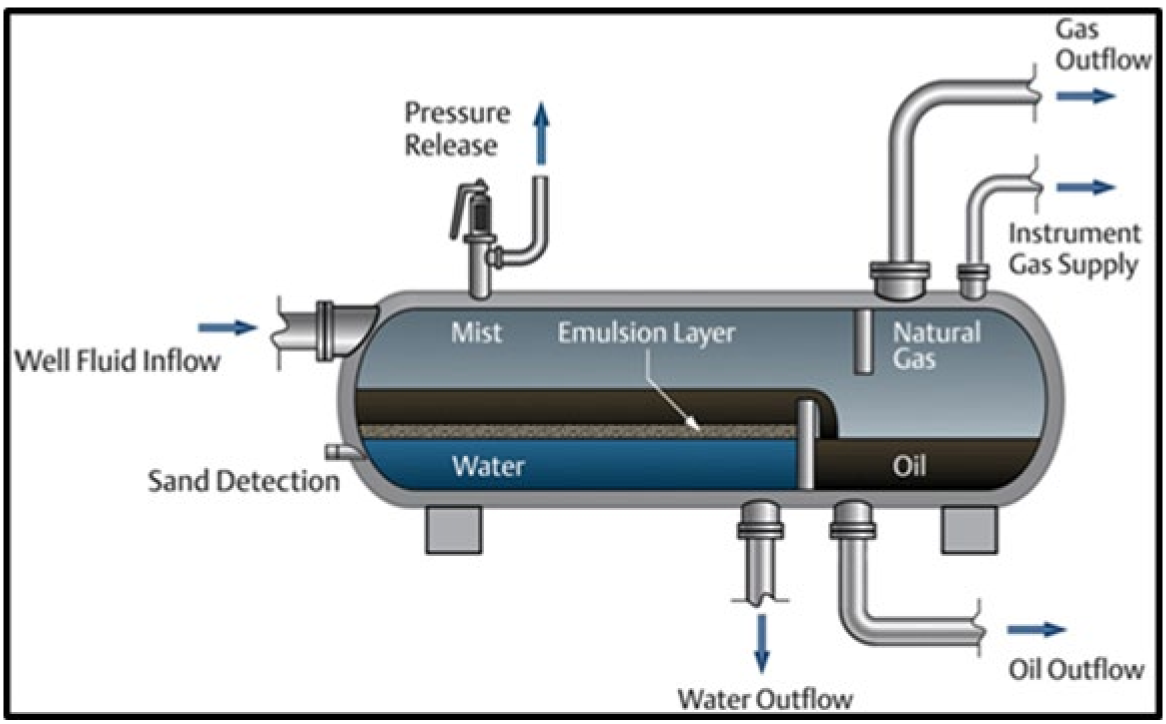

Figure 9-2. Schematic of Test Separator (Emerson[8], 2020).

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[8] https://www.emersonautomationexperts.com/2014/industry/oil-gas/importance-of-flow-measurement-for-separators/

Figure 9-3. Sample collection at test separator. Left: Maxxam employee collecting sample from test separator access port. Right: Sealed well samples.

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 make adjustments on site to improve the amount of water flow. After adjustments were made, a mixture of oil and water was discharged into the 1L opaque amber bottles (Figure 9-3).

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 1L bottles.

In all cases, two 1L opaque amber bottles of sample were collected on each well. The bottles were filled up to the very top with aquifer 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 Metals 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.

Sour gas (H_2S – hydrogen sulfide) was present at all the sites sampled. For this reason, safety precautions were taken by field samplers, including wearing H_2S sensors, and always having two personnel on site for sample collection. Where the H_2S content was high (above 10 ppm), Self Contained Breathing Apparatus (SCBA) with an oxygen tank was used to ensure the field samplers were safe.

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.

A total of 99 samples from different UWI's were collected for analysis in the Clearwater, Rocky and Exshaw Sub-Properties. 16 wells are located within the CCRA. The results of the sampling program are discussed in Section 11.

Large volume samples (3 to 20 m^3) have also been 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 H_2S using AMGAS proprietary CLEAR[9] technology and stored in 1 m^3 totes.

10 Drilling

There has been no drilling completed by E3 Metals Corp. on the project. Readers are referred to Section 9 for details on brine collection from existing wells in the project area.

11 Sample Preparation, Analyses and Security

11.1 Sample Preparation and Security

Samples were collected from oil and gas infrastructure into 1L opaque amber bottles (for detail see Section 9.2). 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 (UWI) and date, and an E3 Metals custody seal was applied for security. These samples were kept secure in a cooler with their chain of custody information and delivered either to Maxxam Laboratories Edmonton or AGAT Laboratories Calgary for processing. Both AGAT and Maxxam are accredited by the Canadian Association of Laboratory Accreditation Inc.

In the laboratory, samples from the same UWI were combined into a large beaker in a fume hood for H_2S 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 is reported along with the lithium result. After H_2S removal, the larger sample was stirred using a stir-bar for at least 1 minute prior to subsampling to ensure sample homogeneity. 100 ml or 125 ml of sample was discharged into two opaque amber glass or high-density polyethylene bottles for trace metals testing at AGAT Laboratories in Calgary, AB (assay lab) and Maxxam Laboratories in Burnaby, BC (duplicate lab). The samples were preserved with 2% by weight nitric acid, and then they were well packed and transported to their respective destinations with their chain of custody documents.

[9] https://www.am-gas.com/clear

Samples received at the individual labs were mixed vigorously and a subset of sample was placed in a digestion tube. The samples 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 is to break down humic acid and various organics in the sample that are believed to interfere with the lithium measurement. Samples are then diluted and run through an ICP-OES machine for trace metals analysis.

11.2 Analyses

11.2.1 Standards and Blanks

A standard solution was created at the University of Alberta Alessi Laboratory by Dr. Salman Safarimohsenabad on June 26, 2017. The standard was comprised of a standard Li solution from Fisher Scientific that was diluted to 120 mg/L with de-ionized water. To assess standard quality and suitability for QA/QC purposes, E3 Metals sent a single 120 mg/L lithium liquid sample to each of five industry accredited analysis laboratories: AGAT, Maxxam, ALS, Wetlab and Core Labs. The results are shown in Figure 11-1. The samples ranged between 0.8% and 2.5% of the 120 mg/L standard solution.

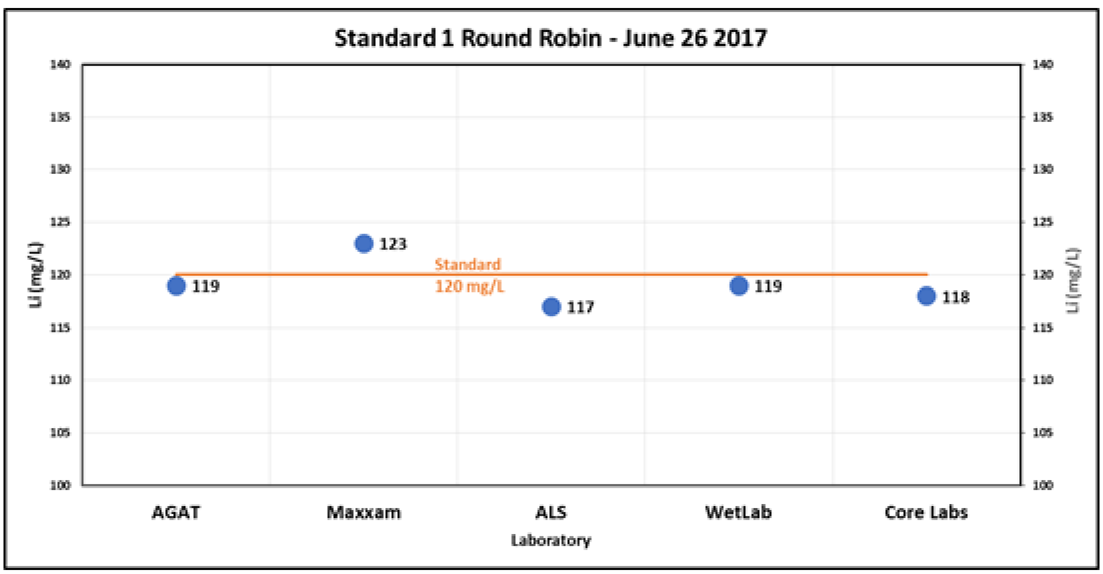

Figure 11-1. Results of lithium standard analyses from five laboratories.

Additional standard batches were created by Dr. Salman Safarimohsenabad throughout 2017 and 2018 to support E3 Metals' sampling programs. Standards and blanks were inserted into ICP-OES analysis runs every 15-20 samples to ensure precision and accuracy.

11.2.2 Duplicate Analysis

Duplicate well brine samples from E3 Metals sub-properties (Clearwater, Rocky and Exshaw) were analyzed by both AGAT and Maxxam in 2017. The resultant scatter plots of the duplicate samples for each lab indicate that AGAT had a higher correlation coefficient (R^2 = 0.8976, 1 being perfect correlation) and a lower y-intercept value (1.9507) (Figure 11-2 and Figure 11-3). Based on the accuracy of the results, and logistical concerns, AGAT and Maxxam laboratories were chosen as the primary and check labs, respectively.

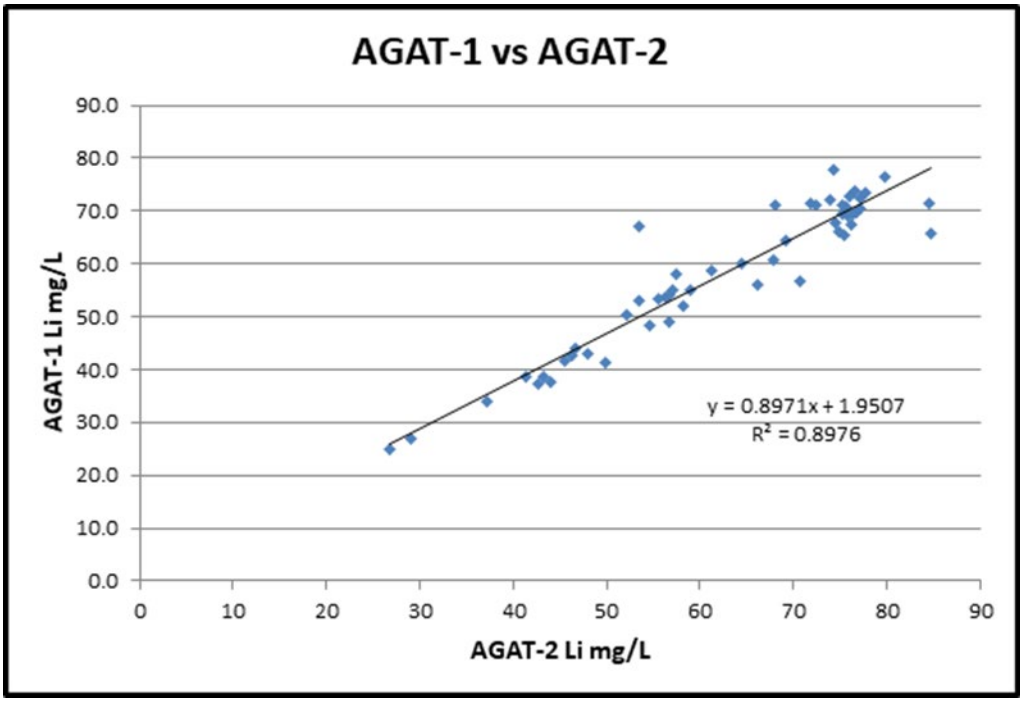

Figure 11-2. Scatter plot of duplicate Li-brine well sample analyses from AGAT laboratory.

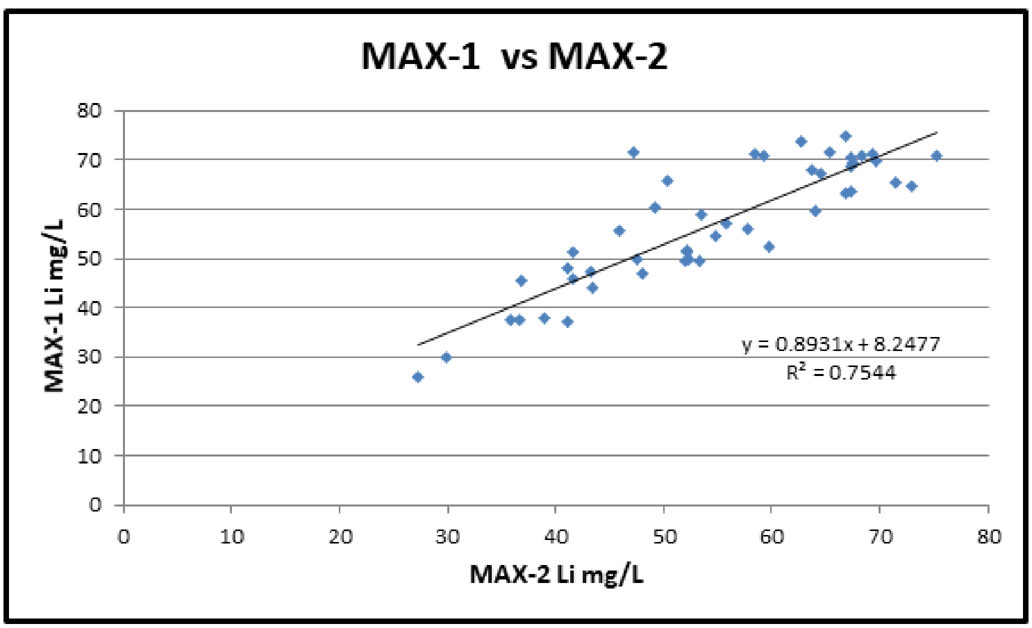

Figure 11-3. Scatter plot of duplicate Li-brine well brine sample analyses from Maxxam laboratory.

11.2.3 Sampling Program Results

Sampling results from across the resource permit areas are presented in Table 11-1 and Figure 11-4. Over 80 samples were collected in these areas. It is the author's opinion that the data presented in this section has resulted from adequate sample preparation, security and analytical procedures. Average brine chemistries from routine and trace metals scan analysis in the CCRA is presented in Table 11-1.

Table 11-1. Aggregate sampling results from E3 Metals' well sampling program (2017-2020).

Resource Area	Min Li (mg/L)	Average Li (mg/L)	Max Li (mg/L)	Number of individual wells sampled	Number of repeat samples collected
Clearwater	67.5	74.6	93.0	16	18
Exshaw West	44.4	75.0	84.8	22	8
Rocky	26.7	52.9	61.3	18	4
Total				**56**	**30**

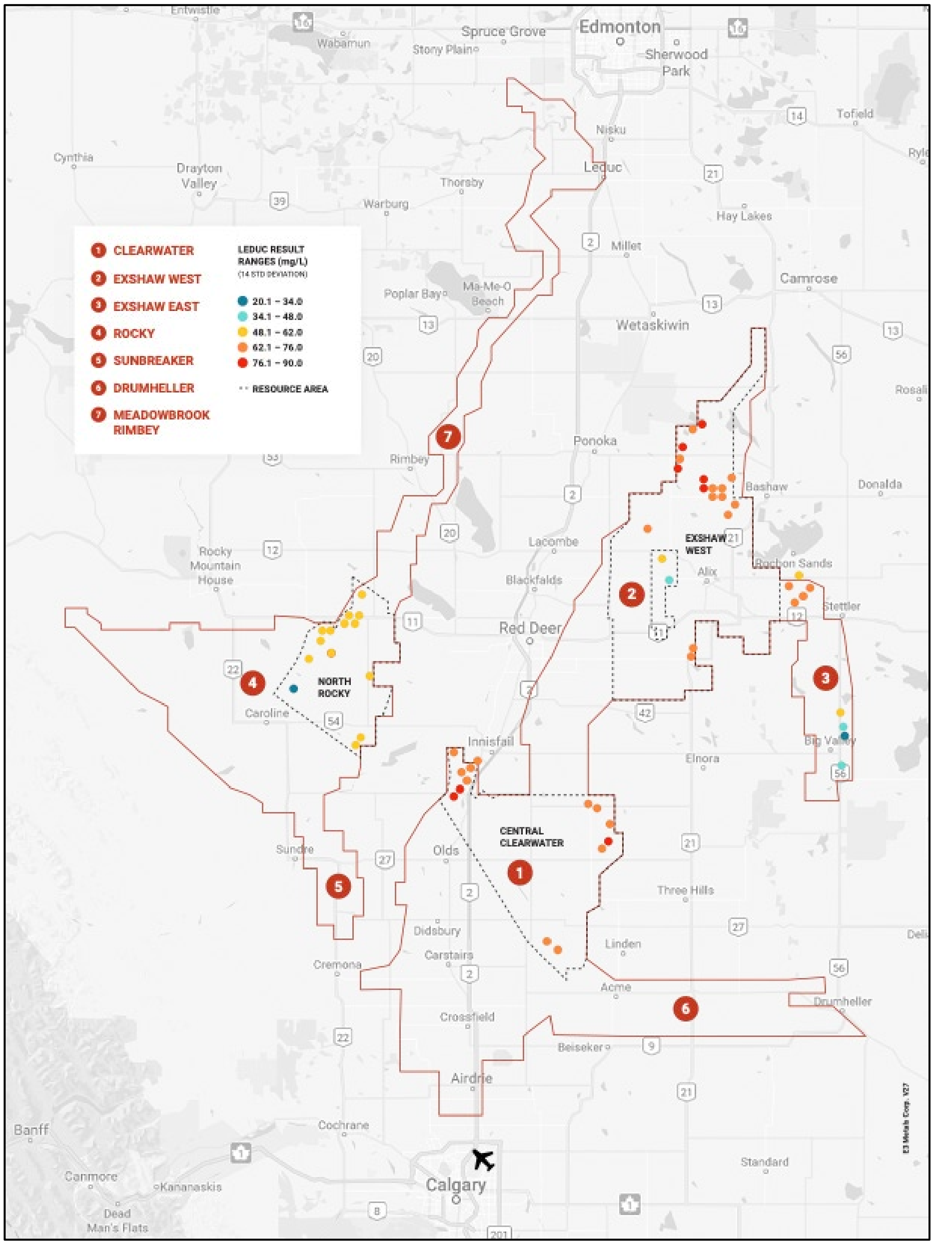

Figure 11-4. Lithium results across E3 Metals' permit area. The Leduc is enriched in lithium across the tested areas, and the data demonstrates consistency throughout sub-properties (E3 Metals Corp., 2020).

Table 11-2. Average chemical analyses of major cations and anions samples collected across the CCRA.

Measurement	Mean
Trace Metals Analysis	
Total Arsenic (mg/L)	2.9
Total Barium (mg/L)	3.3
Total Boron (mg/L)	286.1
Total Lithium (mg/L)	74.6
Total Manganese (mg/L)	0.2
Total Silicon (mg/L)	13.4
Total Strontium (mg/L)	1,158
Total Calcium (mg/L)	24,552
Total Magnesium (mg/L)	2,891
Total Sodium (mg/L)	50,530
Total Potassium (mg/L)	6,882
Routine Water Analysis	
pH	7
Alkalinity (Total as $CaCO_3$) (mg/L)	428.8
Bicarbonate (HCO_3) (mg/L)	524
Conductivity (µS/cm)	318,553
Dissolved Chloride (Cl) (mg/L)	145,703
Fluoride (F) (mg/L)	7.4
Dissolved Sulphate (SO_4) (mg/L)	281.9
Dissolved Calcium (Ca) (mg/L)	23,574
Dissolved Magnesium (Mg) (mg/L)	2,811
Dissolved Sodium (Na) (mg/L)	49,453
Dissolved Potassium (K) (mg/L)	6,372
Dissolved Iron (Fe) (mg/L)	0.1
Dissolved Manganese (Mn) (mg/L)	0.2
Calculated Total Dissolved Solids (mg/L)	228,264
Sodium Adsorption Ratio	80.7
Hardness (mg $CaCO_3$/L)	70,425
Total Suspended Solids (mg/L)	347.5

11.2.4 Temporal Variation

Between 2017 and 2019, E3 Metals analyzed a total of 34 brine samples from the CCRA. This included samples from 16 individual wells, with 4 or more repeat samples collected at 4 different locations. A graphical summary of lithium concentration measurements in the 4 wells with repeat samples is shown in Figure 11-5, Figure 11-6, Figure 11-7 and Figure 11-8. All analytical results fall within acceptable limits as prescribed by the laboratory. These graphs suggest lithium concentrations are unchanged over time in the CCRA.

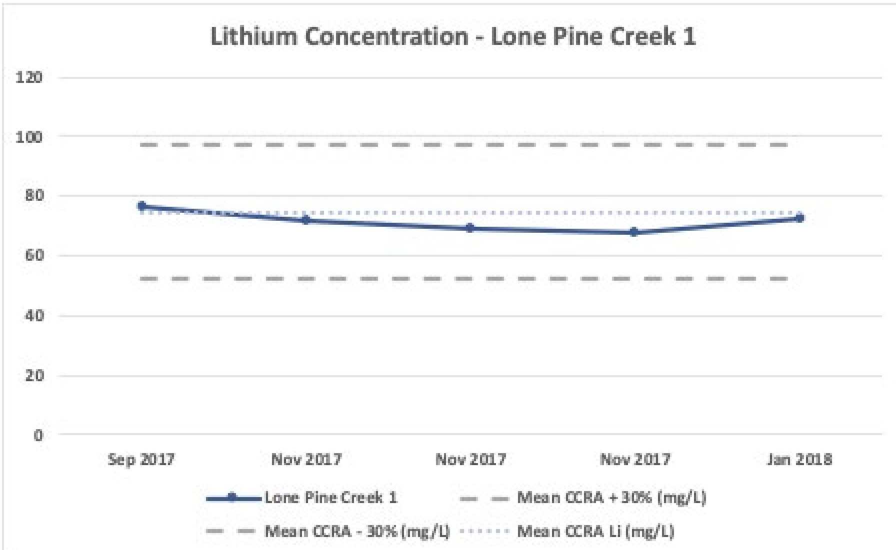

Figure 11-5. Lithium Concentrations measured at Lone Pine Creek 1 between 2017 and 2019. Dotted line indicates the mean (74.6 mg/L). Dashed lines represent +/- 30% of the mean.

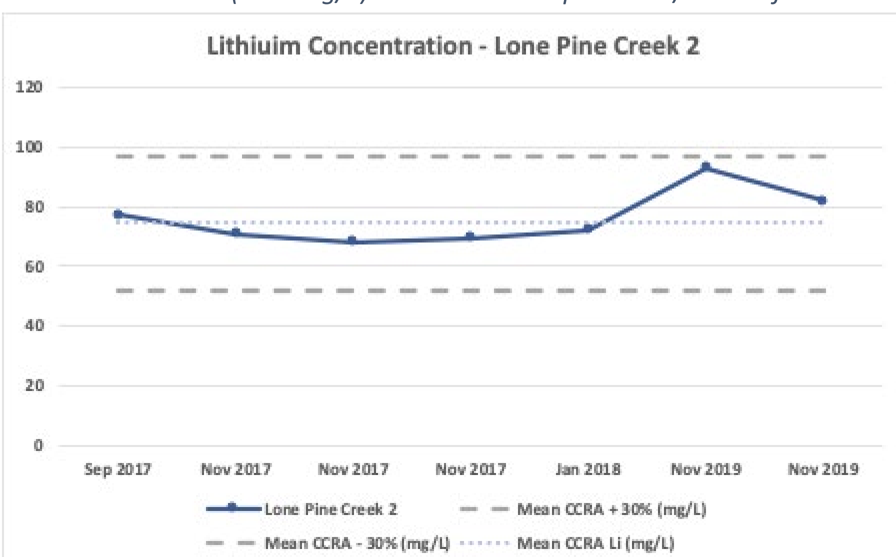

Figure 11-6. Lithium Concentrations measured at Lone Pine Creek 2 between 2017 and 2019. Dotted line indicates the mean (74.6 mg/L). Dashed lines represent +/- 30% of the mean.

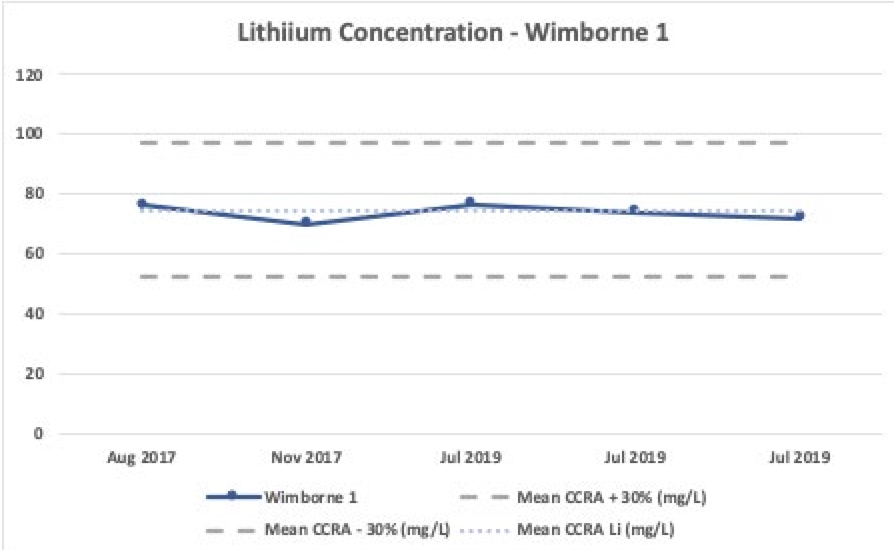

Figure 11-7. Lithium Concentrations measured at Wimborne 1 between 2017 and 2019. Dotted line indicates the mean (74.6 mg/L). Dashed lines represent +/- 30% of the mean.

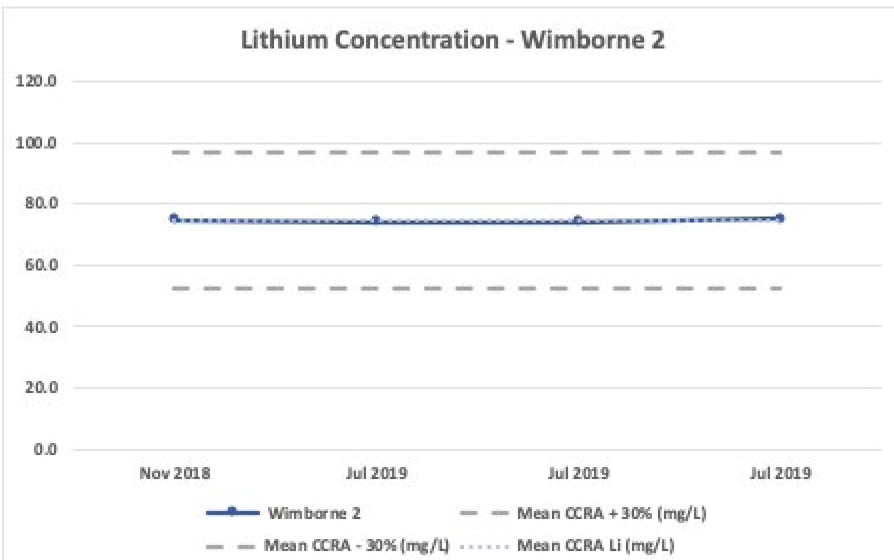

Figure 11-8. Lithium Concentrations measured at Wimborne 2 between 2017 and 2019. Dotted line indicates the mean (74.6 mg/L). Dashed lines represent +/- 30% of the mean.

12 Data Verification

The author has reviewed the field sampling Standard Operating Procedure (SOP) and the Laboratory Testing SOP developed by E3 Metals to ensure consistent and accurate sample collection and analysis. The author has additionally reviewed the Quality Assurance/Quality Control results provided by E3 Metals and reviewed the reports provided for each lithium sample by the laboratory. The author is satisfied that data presented in this Report is adequate for the purposes of calculating an Inferred Resource.

One component of the Quality Assurance program was for the current, and previous authors to witness sample collection in the field. The previous author of the CCRA Inferred Resource (2017) observed Maxxam employees collect samples as described in Section 9.2 from two 3-phase test separator facilities during a September 18, 2017 site visit. During the observation, Maxxam employees demonstrated a competency of the E3 Metals SOP and executed sampling accordingly. The site was located on the Clearwater Sub-Property within the CCRA. Samples were delivered to the laboratory for degassing by Maxxam field staff upon the completion of the sampling program.

Figure 12-1. The author of the 2017 "Lithium Resource Estimate for the Central Clearwater Property South-Central Alberta, Canada" inspecting separator test samples collected during the site inspection.

During a March 23, 2018 site visit, the current author observed Maxxam employees collect samples as described in Section 9.2. During the observation, Maxxam employees demonstrated a competency of the E3 Metals SOP and executed sampling accordingly. The sites were located in the Clive sub-property of the

Exshaw West Resource Area, north of the CCRA but in the same contiguous Leduc reef trend as the CCRA. Samples were delivered to the laboratory for degassing by Maxxam field staff upon the completion of the sampling program.

Starting in 2019, Maxxam Laboratories now operates as Bureau Veritas Laboratories and E3 continued to work with the same field staff for sampling programs in 2020.

There are a series of historical sampling results scattered throughout the E3 Metals Permit Area. This historical data is available through the Alberta Geological Survey[10]. The specific circumstances under which the samples were taken are unknown and accordingly this data has not been included in the Resource calculation. As expected, the historical data for across the trend are relatively consistent with the data presented in this Report, aside from several outliers over 100 mg/L lithium.

13 Mineral Processing and Metallurgical Testing

13.1 Introduction

The preliminary process design presented in this Report is based on the data provided for the ion exchange sorbent performance test results completed by E3 from 2019 to 2020. All test work data considered in the writing of this Report was conducted at bench scale by GreenCentre Canada, an independent sustainable chemistry and advanced materials laboratory located in Kingston, Ontario.

13.2 Sample Source

All test work referenced in this Report was completed using brine sourced from the Leduc Aquifer. To facilitate test work, a large volume brine sample (20 m^3) was collected from the water leg of a 3-phase separator on an operating oil and gas well in 2019 using the same methods described in Section 9. The 20 m^3 sample collected was treated by AMGAS using their proprietary CLEAR[11] technology to remove H_2S without introduction of chemicals to the brine. Once treated, the sample was then stored in 1 m^3 plastic totes in Calgary, Alberta.

Ion exchange sorbent test work was completed using brine sourced from the Leduc Aquifer and heated to elevated temperatures consistent with the expected brine temperature upon delivery to the central processing facility (70°C).

[10] https://ags.aer.ca/activities/lithium
[11] https://www.am-gas.com/clear

13.3 Key Findings

Test results to date indicate that:

- The ion exchange sorbent has high selectivity for lithium over other ions present in significantly higher quantifies in Leduc brine (incl. Na, Mg, Ca).
- High lithium recovery from Leduc brine can be achieved with the ion exchange sorbent at bench scale.
- The absorption reaction kinetics of lithium extraction from brine onto sorbent is particularly rapid and occurs within minutes whereas the stripping of lithium from sorbent into the eluate occurs at a slightly lower rate.
- The ratio of sorbent mass to brine volume is relatively small due to the high lithium loading on the sorbent achieved at lab scale.
- The sorbent has a defined lifespan represented by the sorbent cost outlined in economic analysis.

13.4 Risk and Assumptions

Continued test work is currently being conducted to determine the most effective ion-exchange media form for sorbent performance, kinetic reaction and equilibrium results. The final results of this work will determine the operating conditions and process equipment configuration for a commercial process.

E3 Metals Corp. is currently completing bench scale flow testing to test the sorbent against various process flow conditions. Once this bench scale flow testing work has been completed, E3 plans to build a pilot-scale-prototype plant which will be used to optimise operating parameters and conditions for a commercial operation in Alberta.

When this Report was written, the concentrate polishing steps in the proposed design have not been tested on lithium concentrate generated with the developed ion exchange sorbent. However, all the process steps are standard, well proven technologies. A number of assumptions were made, specifically with regard to the performance of the secondary purification stage where impurities (largely Ca and Mg) are removed via precipitation. These assumptions need to be tested and the overall flowsheet should be fully simulated at laboratory scale.

13.5 Conclusions and Recommendations

The focus of test work completed to date has been on the primary selective extraction of lithium from Leduc brine as this process step is in development and requires the greatest attention. Larger scale test work and sorbent development is required to confirm the process performance and optimise the design of the primary extraction and elution circuit.

The proposed downstream processes are robust, well-proven and practical at the scale of the intended plant.

14 Mineral Resource Estimates

The mineral resource estimate was completed by a multi-disciplinary team led by Fluid Domains Inc. with Gordon MacMillan acting as the QP. The estimate was completed using a three-dimensional numerical model of groundwater flow. The model incorporates aquifer geometry, porosity, permeability, specific storage, pressure, and lithium concentrations. The mineral resource estimate benefited from a considerable amount of data compiled by the oil and gas industry and made public by the Government of Alberta.

14.1 Aquifer Geology

14.1.1 Aquifer Geometry

Petroleum drill well data, described in Section 6, was used to define the shape and extent of the Leduc and Cooking Lake aquifers. Defining the geometry of the Leduc and Cooking Lake aquifers is an iterative process which involves analysis of existing wells drilled for the exploration and production of hydrocarbons in the 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.

A total of 50 wells in and around the resource areas penetrate the full stratigraphic section of the Leduc and Cooking Lake aquifers. 243 wells penetrate the top of the Leduc aquifer and were not drilled deep enough to intersect the lower Cooking Lake aquifer. This is typical of wells drilled for the purpose of hydrocarbon production in the Leduc specifically.

The Leduc reef edge is defined as the point at which the Leduc Reef Margin slope is no longer distinguishable (zero-edge). This edge differentiates the high porosity reefal buildups of the Leduc 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 was defined primarily using well data. In the absence of well data, existing industry-standard Leduc edge interpretations were consulted (Mossop et. al., 1994; GeoScout Devonian Subcrop, 2017). The local and regional geological context was also taken into consideration when making interpretations.

The Leduc sits atop the limestones and dolomites of the regionally extensive Cooking Lake, which is differentiated from the Leduc by the presence of a regional argillaceous (shale) zone. This argillaceous zone is not present in all wells, and in those cases the top of the Cooking Lake was defined based on offsetting wells using relative thicknesses and geological context. Generally, the Cooking Lake has a slightly lower gamma ray response than the Leduc. The base of the Cooking Lake was chosen where the more argillaceous Beaverhill Lake Group became evident.

The Leduc reef built upwards from the Cooking Lake platform and occurs today as a prominent feature in the stratigraphic column. These reefs, some of which reached heights of over 300 m, are overlain and encased laterally by the shales of the Ireton and Duvernay.

The Ireton shale drapes over top of the Duvernay, Leduc and Cooking Lake and forms the primary hydrocarbon trap and aquitard of the Leduc system. It is generally identified using the Gamma Ray well log. The presence of clays and associated minerals generally increases the radioactivity of rocks, and the Ireton can be distinguished from the Leduc by its higher radioactive signature on the Gamma Ray well log. The Ireton and Duvernay may be distinguished by subtleties in the radioactive gamma ray signature (Ireton has a higher gamma signature than the Duvernay). Duvernay and Ireton may also be distinguished from each other using the induction well log. At the molecular level, the Ireton most often contains water, whereas the Duvernay most often contains hydrocarbons, which decreases its conductivity.

14.1.2 Hydrostratigraphic Units

Hydrostratigraphic (flow unit) definitions were determined based on their hydraulic properties and their potential to contribute to regional groundwater flow. The flow units were defined and subdivided as follows:

- *Leduc Reef Margin*: Outer edge of the Leduc Reef
  - Wimborne Margin
  - Innisfail Margin
- *Leduc Platform Interior*: Area Bounded by Reef Margins
  - Clearwater Interior
  - Innisfail Lagoon
- *Cooking Lake Platform*: Present throughout Resource Area

The hydrostratigraphic units were based on trends of porosity (pore space in the rock) and permeability (ability for fluid to flow in the rock). Trends of porosity and permeability occur spatially and relate to depositional environments. These trends (also called facies models) are established in the literature for the Leduc aquifer (Hearn, 1996; Potma et al., 2001; Atchley et al., 2006) and formed the basis for hydrostratigraphic definitions.

The reef margin is defined based on its position on the platform and forms the edge of the reef buildup. These facies (rock types) are typical of high energy environments where most of the aggradation and reef growth occurred, and therefore is typically the best part of the primary aquifer with the highest porosity and permeability.

Comparisons of modern and Triassic aged reefs indicate slopes along the reef margin range from approximately 20 degrees to up to 35 degrees (Schlager & Reijmer, 2009). This is expected to be consistent with Devonian-aged reefs, and an average of 25-degree slope was selected for the Leduc in the region.

The width of the margin over the Bashaw complex has been mapped with widths ranging from 10's of meters to approximately 5 km (Atchley et. al., 2006; Hearn, 1996). The margin width is dependent on several factors, including reef topography, prevailing wind direction, and spatial reef geometry. Thinner margins are expected where the reef is locally protected or drowned, whereas thicker margins are expected where the reef is located in a windward position. An average width for the margin of 1.0 km was selected based on the literature, and adjustments in specific areas were made where the data indicated a wider margin (e.g., 2.5 km wide at Wimborne field).

The platform interior is a lagoonal setting on the back side of the reef margin and is dominated by facies common in lower energy environments. These interiors (or lagoons) are bounded by the margin facies. These depositional environments consist of carbonate muds, storm washover debris, shoal reef material, and occasional patch reefs.

Based on the aggrading (vertical upwards growth) and in some cases backstepping (vertical backwards growth) nature of the Devonian Leduc reef buildups (Stoakes, 1992), the facies were assumed to be vertically continuous throughout the reef thickness.

The Cooking Lake aquifer is a carbonate platform that sits beneath the Leduc. This aquifer encompasses the flow unit below the Leduc aquifer and above the Beaverhill Lake and is continuous beneath and beyond the Central Clearwater Resource Area.

14.1.3 Structure and Thickness

Geological mapping was completed by E3 Metals and formation tops were provided to Fluid Domains for construction of geologic surfaces and isopachs (thickness maps). The geologic data set used to construct the model is comprised of 837 wells with Leduc structure tops, 220 wells with Cooking Lake structure tops, and 201 wells with Beaverhill Lake structure tops.

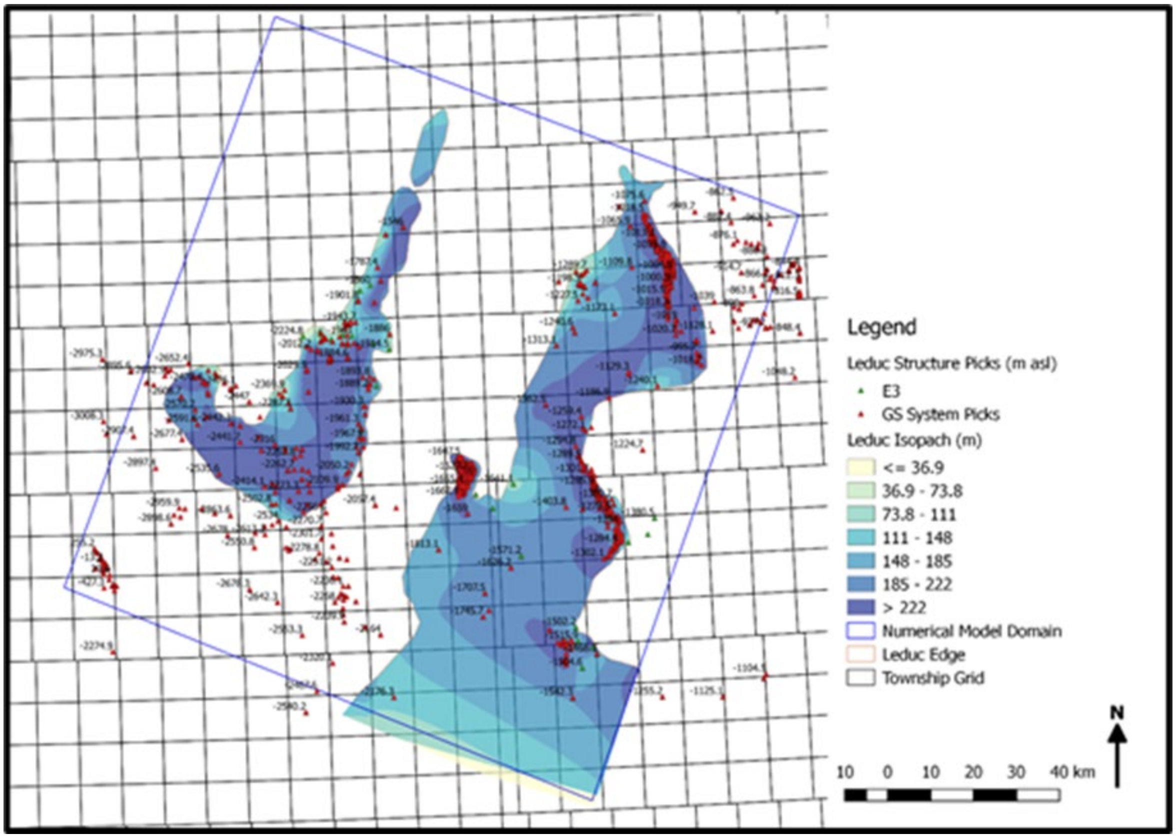

Figure 14-1. Isopach map of the Leduc Aquifer

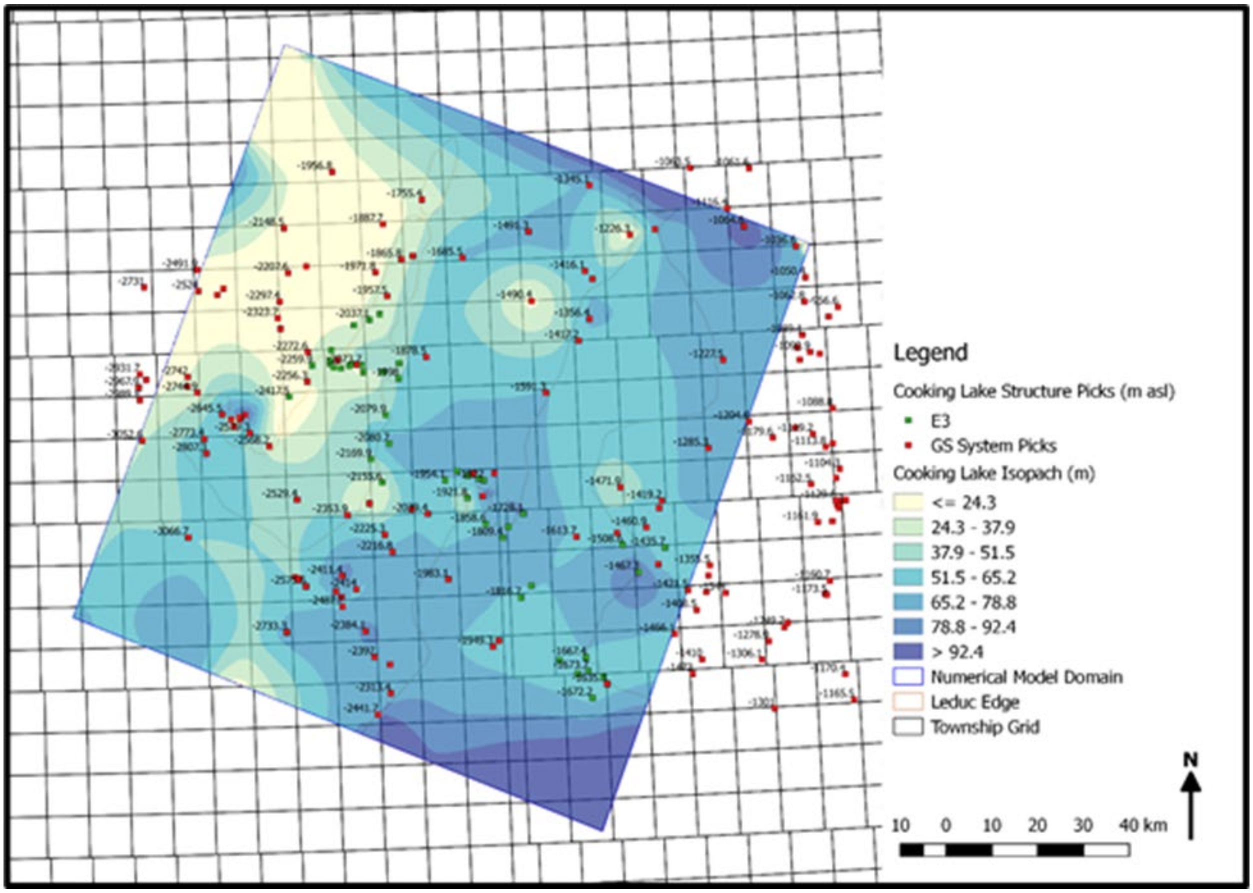

Figure 14-2. Isopach map of the Cooking Lake Aquifer

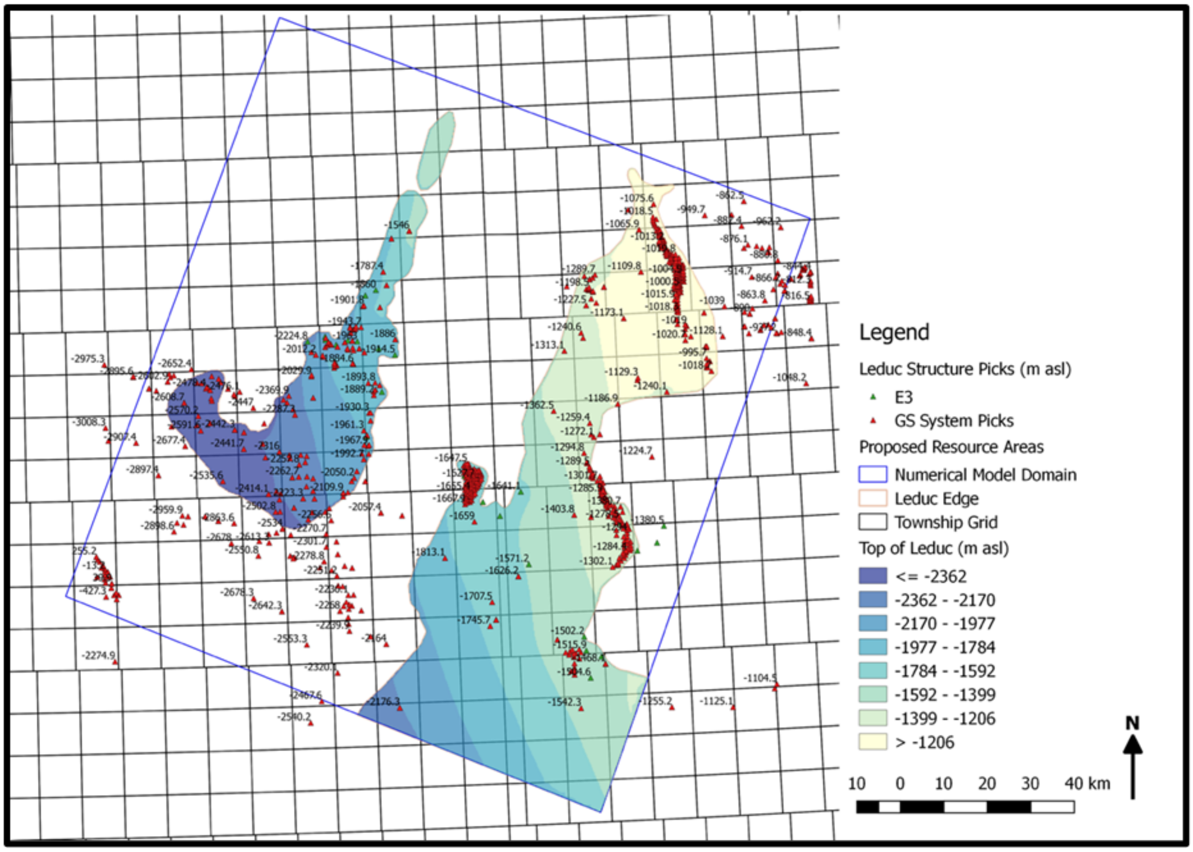

Figure 14-3. Structure top of the Leduc Aquifer.

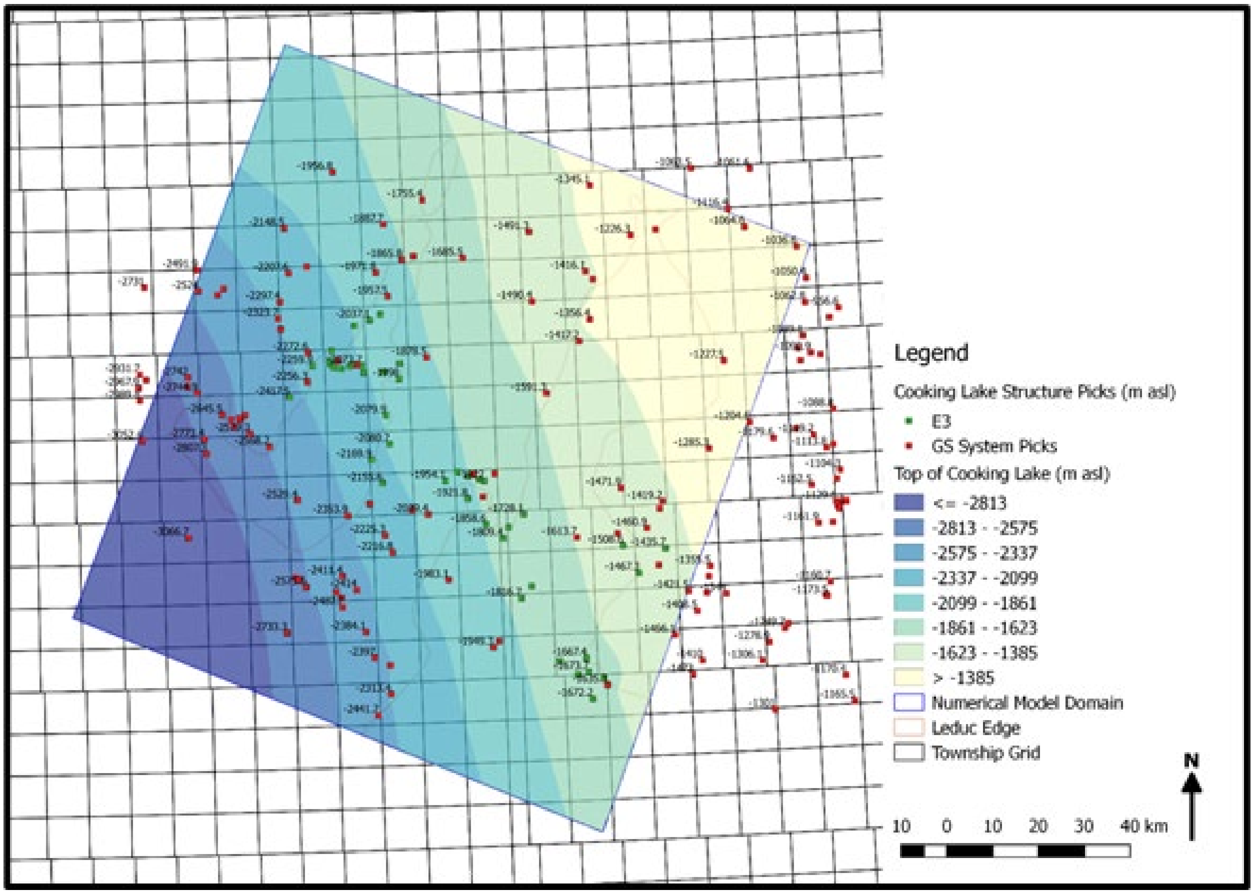

Figure 14-4. Structure top of the Cooking Lake Aquifer

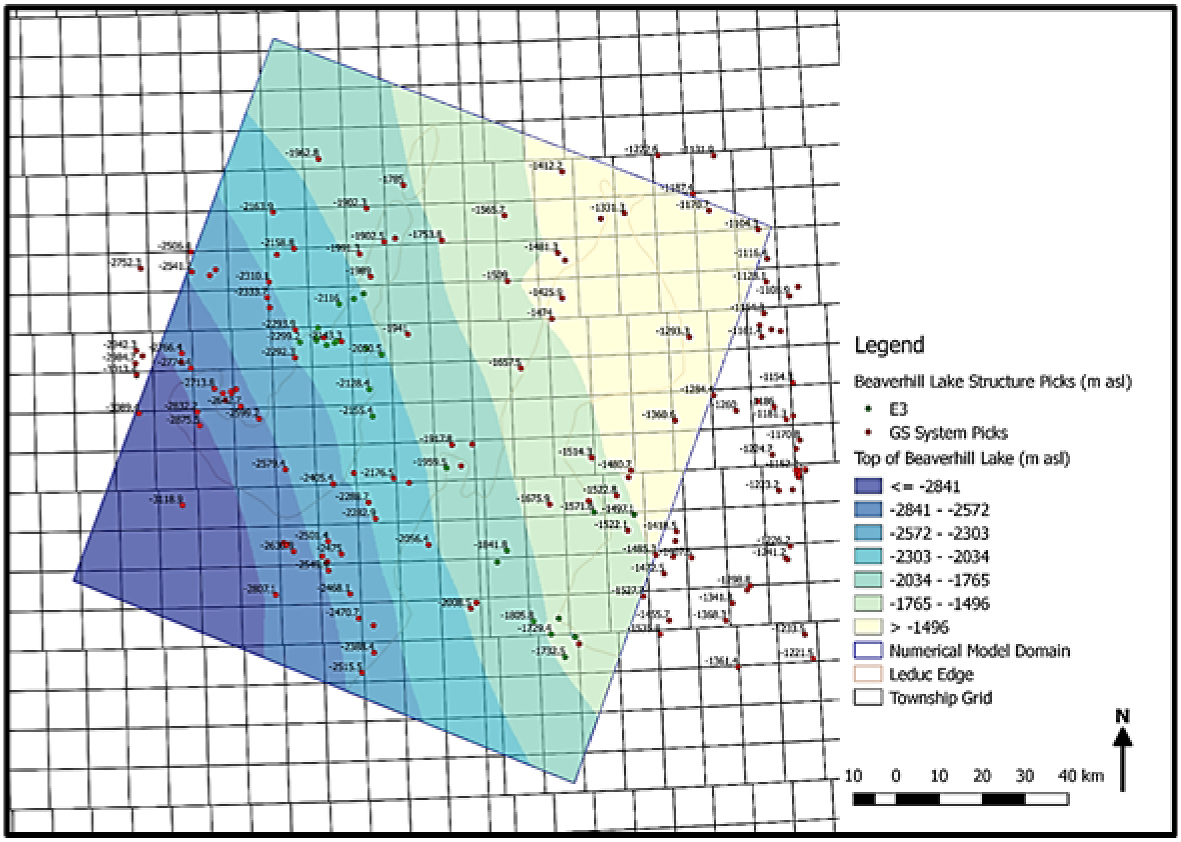

Figure 14-5. Structure Top of the Beaverhill Lake Group

Isopach maps of the Leduc and Cooking Lake (Figure 14-1 and Figure 14-2) and maps depicting the top of the Leduc (Figure 14-3), Cooking Lake (Figure 14-4) and Beaverhill Lake (Figure 14-5) were created by Fluid Domains. The top of the Beaverhill Lake Group reflects a regional dip to the southwest of approximately 1.6% (Figure 14-5).

14.2 Aquifer Properties

The work described in this Report benefited from a considerable amount of data compiled by the oil and gas industry and made public by the Government of Alberta. The data was accessed through third party software providers (geoLOGIC 2017 and Divestco 2020).

Key data sets used to determine aquifer parameters in the resource area are described in Section 6 and include drill stem tests (pressure, water quality, and permeability), core plug analyses (porosity and permeability), downhole wireline logs (lithology, porosity, effective porosity and permeability), and historical production volumes of hydrocarbons and water (context for aquifer pressure and aquifer continuity).

Hydrocarbon production has taken place in the vicinity of the resource area since 1961 resulting in a considerable amount of data to constrain aquifer parameters: 327 drill stem tests (DSTs) with pressure build-ups and extrapolated pressures; 7,701 core plug analyses; and historical water production from 200 wells between January 1961 and August 2020.

14.2.1 Aquifer Pressure

Drill Stem Test data from 327 wells with Leduc or Cooking Lake extrapolated pressures passed Quality Control and were used by Fluid Domains in an area surrounding and including the resource area. DSTs are downhole tests that can yield pressure and permeability (flow capability) measurements from a specific depth interval. Equivalent freshwater hydraulic head was determined from the DST pressures, and is calculated to normalize pressure data for comparative analysis. This measurement is calculated in "metres above sea level" (masl). The equivalent freshwater hydraulic head was observed to decrease over time in response to the historical production of fluids and gases throughout the region. Considering that the pressure data was measured in wells that are distributed throughout the region, the trends in each resource area suggest the Leduc Aquifer is hydraulically connected across the margin and interior portions of each reef.

Distinctly different trends, however, were observed in the CCRA in comparison to other areas of the Leduc (Figure 14-6). Given the long period of available data and the apparent persistence of separate pressure trends, this suggests that non-contiguous areas of the (I.e., Leduc reefs in the Rocky and Clearwater areas) are not well connected to each other hydraulically. The Cooking Lake Aquifer is present below the Leduc regionally, and is assumed to connect non-contiguous areas. The persistence of separate pressure trends in non-contiguous areas suggests the Cooking Lake has low permeability.

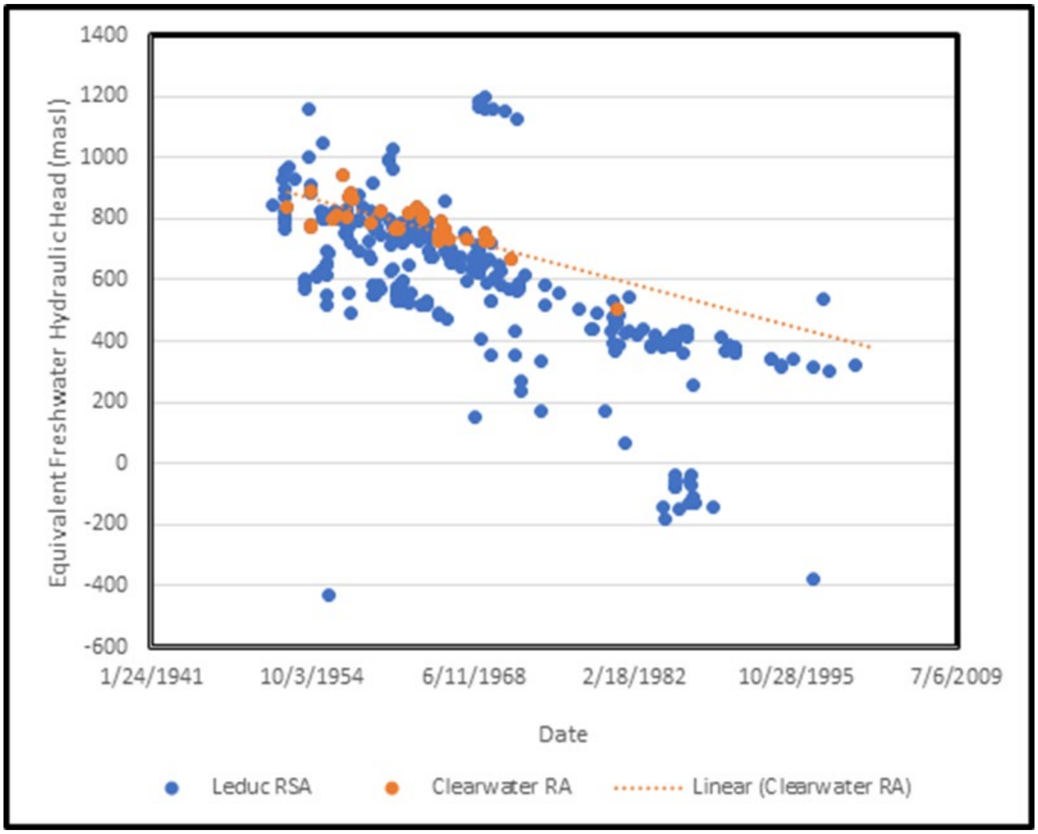

Figure 14-6. CCRA DST derived hydraulic heads over time as compared to regional data.

Pressures throughout the CCRA are observed to have decreased in response to historical fluid production. Equivalent freshwater hydraulic heads are estimated to have decreased from 850 masl in 1961 to 300 masl in 2020. Based on a top of Leduc elevation in this area calculated at -1,500 masl, there is an estimated 1,800 m of available head in the Leduc.

14.2.2 Aquifer Permeability

Multiple techniques were used to determine the permeability of the aquifers. In addition to published permeability estimates of the Leduc and Cooking Lake aquifers, the permeability of hydrostratigraphic units in the resource area were further informed through two measurement techniques: core plug test analysis and DST analysis.

DST analysis was completed by Melange Geoscience Inc. on a subset of what was considered high-quality DST data. Pressure build-up curves were analyzed on 5 DSTs in the CCRA. DSTs were selected for analysis from both the reef margin and reef interior (Table 14-1).

The core plug permeabilities reflect high quality estimates of permeability on a small-scale (cm-scale) and the DST derived permeabilities reflect high quality estimates of permeability on a local-scale (m-scale to

10s of m-scale). Given the larger scale of the DST permeability estimates, these were preferred for the characterization of the hydrostratigraphic units. Table 14-1 provides a summary of the permeability data.

Table 14-1. CCRA porosity and permeability from core, log and DST analysis.

Formation	Hydrostratigraphic Unit	E3 Core Analysis		E3 Log and Core Analysis			Melange DST Analysis			
		Count	Geomean Permeability (mD)	Estimated kv/kh	Porosity of Net Interval	Ratio of Net/Gross	Count	Min Permeability (mD)	Max Permeability (mD)	Geomean Permeability (mD)
Leduc	Innisfail Margin	2,206	37	0.62	6.3%	1.00	0	---	---	---
	Innisfail Lagoon	1,893	45	0.46	6.3%	0.58	0	---	---	---
	Clearwater Interior	153	17	0.06	6.0%	0.58	3	19	77	46
	Wimborne Margin	3,449	45	0.30	7.8%	1.00	2	1,721	4,646	2,828
	South Clearwater	---	---	---	---	---	---	---	---	---
Cooking Lake	Regional	0	---	---	---	---	---	---	---	---
	Below 'Clearwater' reef	0	---	---	2.0%	0.00	---	---	---	---

The best estimates of representative horizontal permeability were selected to be equal to the geometric mean of the DST data where DST data was available (Table 14-1). For hydrostratigraphic units where DST data was not available, the representative horizontal permeability was assumed to be a function of the DST derived permeability of an analogous hydrostratigraphic unit and the representative permeability was scaled based on core data (Table 14-1).

Table 14-2. Summary of aquifer parameter values used in the model construction.

Formation	Hydrostratigraphic Unit	Model Construction					
		Horizontal Permeability (mD)	Vertical Permeability (mD)	Horizontal Hydraulic Conductivity (m/s)	Vertical Hydraulic Conductivity (m/s)	Specific Storage (m^{-1})	Effective Porosity
Leduc	Innisfail Margin	2,319	1,443	6.45E-05	4.02E-05	1E-06	0.06
	Innisfail Lagoon	124	57	3.45E-06	1.59E-06	1E-06	0.04
	Clearwater Interior	46	3	1.28E-06	8.35E-08	1E-06	0.03
	Wimborne Margin	2,828	858	7.87E-05	2.39E-05	1E-06	0.08
	South Clearwater	3	0.3	2.78E-08	2.78E-09	1E-06	0.02
Cooking Lake	Regional	1	0.1	2.78E-08	2.78E-09	1E-06	0.02
	Below 'Clearwater' reef	1	0.1	2.78E-08	2.78E-09	1E-06	0.02

Vertical permeability (k_v) is a measure of how easily fluid will flow vertically within the aquifer and was estimated and entered into the flow model. Typically, fluids will move more easily in a horizontal direction in sedimentary rocks. Vertical permeability is not captured by DST analysis and was therefore determined using core plug analysis.

Table 14-1 summarizes the vertical anisotropy based on core data. The vertical anisotropy was calculated by dividing the arithmetic average vertical permeability by the arithmetic average value of horizontal permeability (k_h). The vertical anisotropy of each hydrostratigraphic unit was multiplied by the estimated horizontal permeability to determine a representative vertical permeability for the flow model. Overall, the permeability in the horizontal direction is greater than the vertical direction in the Leduc aquifer.

Hydraulic conductivity of the aquifer was determined from the aquifer permeability and the properties of the water (viscosity of 4×10^{-4} Pa s and a density of 1,150 kg/m^3). Transmissivity of the aquifer was determined by multiplying the mapped aquifer thickness (Section 14.1) by the hydraulic conductivity.

14.2.3 Aquifer Porosity

Multiple techniques were used to determine the porosity of the aquifers. Porosity estimates of hydrostratigraphic units in the CCRA were informed by facies-based porosity estimates published by Atchley et al. (2006) and further constrained by core plug measurements and wireline data.

Aquifer porosity was determined using several sources of geology and wireline data depending on the location and data availability. Wireline Photoelectric (PE) curve data was used to determine lithology, specifically in this case between limestone and dolomite (Kennedy M.C., 2002). This distinction is important to the characterization of porosity as dolomite typically has a higher porosity than limestone.

The Leduc aquifer has undergone extensive dolomitization in the resource area. Dolomitization generally increases towards the top of the Leduc aquifer. In the CCRA, the Cooking Lake aquifer beneath the Leduc reef is predominantly limestone and has relatively low porosity.

Average porosity for each flow unit was determined using good quality porosity log data, discussed in Section 6.2. 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 (American Association of Petroleum Geologists, 2017). Where available, porosity measurements from core and core plugs were also used to estimate porosity.

The Leduc reef margins typically have more available data due to the drilling density from oil and gas development. Core data (rock property measurements from drill core) is used to infer a reasonable porosity where such data exists in each depositional setting and where porosity log data is limited. Average porosities for the Innisfail and Wimborne margin flow units range between 6-8% (Table 14-1) for all wells drilled in the defined reef margins. Porosity data is supplemented with wireline open hole neutron/density log data where available.

Porosity log data is preferentially used in the absence of core data where wells penetrate the full depth and when each individual log is of good enough quality to derive porosities. Assignments of rock properties for areas of poor well control such as the Innisfail Lagoon and Clearwater Interior flow units rely on well control from analogous areas with good well control. In addition, regional context is applied to interpret porosity, including depositional setting, cross sections and general knowledge of platform architecture. Each of these elements contribute to the estimation of average porosity for the interior platform units Table 14-1).

Net porosity thickness is the total thickness of the aquifer with porosity above a 3% porosity cut-off. A net porosity thickness map represents the rock thickness with measured porosity above 3% and that is expected to contribute to fluid flow. A net to gross ratio is then calculated by dividing the net porosity thickness by the gross thickness of the aquifer. This value represents the relative proportion of the aquifer above the porosity cut-off. Rock with porosity below the cut-off is expected to contribute to the overall system but is not included in the net isopach of the flow unit. Hydrocarbon pore space within the oil and gas fields in the CCRA were excluded from the calculations and a net porosity was not calculated within the oil leg of those areas. The net to gross ratio for the CCRA ranges from 0.6-1.0.

In the CCRA, the Cooking Lake is lower-porosity (tight) limestone. Average porosity in the Cooking Lake at the CCRA is approximately 2% and there were no intervals mapped to have porosity above 3% resulting in a net/gross ratio of zero (Table 14-1). Few wells penetrate to the top of the underlying Beaverhill Lake Group. Wells that did not penetrate the Beaverhill Lake Group were not used because the thickness of the Cooking Lake could not be determined, and net/gross numbers could not be calculated. Instead, wells in the greater surrounding area, including those in the area of interest were used to estimate the average value for porosity for the Cooking Lake. Although the rock properties of the Cooking Lake fall below the porosity cut-off, and therefore do not have a net flow unit value, the Cooking Lake is considered a low flow unit in this area and as it still holds some water in the available pore space and has some developed permeability.

The effective porosity is a value that can be applied to the total thickness of the hydrostratigraphic unit and represents an upscaling porosity value of the net interval (the proportion of the aquifer that contributes most to the migration of brine water and injected water). The effective porosity was calculated by multiplying the porosity of the net interval by the ratio of net to gross. Effective porosity is an important parameter when estimating the groundwater flow velocity and the rate of solute migration.

Estimates of representative porosity based on core data and wireline logs are summarized for each hydrostratigraphic unit in Table 14-2. Leduc aquifer effective porosity values in the CCRA range from 3% in Clearwater Interior to 8% in Wimborne Margin (Table 14-2). Three porosity related values were provided for each hydrostratigraphic unit: the porosity of the net interval (Table 14-1), the ratio of net to gross intervals (Table 14-1), and the effective porosity (Table 14-2).

14.2.4 Storage Estimates of Aquifer

The specific storage of the Leduc and Cooking Lake aquifers in the resource areas were estimated based on the compressibility of water and the compressibility of the rock. The relationship between specific storage (S_s) and compressibility is described by Domenico and Schwartz (1990, page 113).

$$S_s = \rho_w \, g \left(\beta_p + n\beta_w\right)$$

Where:
ρ_w = density of water (M/L^3)
g = acceleration due to gravity (L/t^2)
β_p = bulk compressibility (L^2/Force)
n = porosity
β_w = compressibility of water (L^2/Force)

Based on the effective porosities presented in Table 14-1, a water density of 1,150 kg/m^3, a rock compressibility of 3.3 x 10^{-10} m^2/N, and a water compressibility of 4.8 x 10^{-10} m^2/N, the specific storage in each hydrostratigraphic unit is estimated to be approximately 4 x 10^{-6} m^{-1}. These values are similar to, but slightly greater than, Fluid Domains' experience completing regional scale modelling in the WCSB. For the purposes of the Mineral Resource Estimate, a slightly more conservative regional value of 1 x 10^{-6} m^{-1} was deemed to be representative of Cooking Lake and Leduc aquifers. Storativity of the aquifer was determined by multiplying the mapped aquifer thickness (Section 14.1) by the representative specific storage.

14.3 Estimate of Water Production

14.3.1 Water Production Methodology

The CCRA has an aerial extent of 1,028 km^2 and aquifer thicknesses of greater than 220 m in the Leduc and greater than 90 m in the Cooking Lake. Based on the effective porosities in Table 14-2, there are approximately 9.8 km^3 of aquifer water contained in high permeability zones.

In order to produce lithium, the aquifer water will be pumped to the surface from a production well (produced water). The produced water will need to be processed at the surface in order to remove the lithium and the same volume of water as was pumped to surface, will be injected into the aquifer (injected water).

The rate at which brine can be produced, is a function of the aquifer properties (hydraulic conductivity, thickness, specific storage, and available head) and of the production well network design (number of wells and well spacing).

The duration that a production well would pump is expected to be limited by the arrival of injected water with low concentrations of lithium (injected water) at the production well. The arrival time of injected water at a production well and the degree of mixing between injected water and aquifer water, will be a function of the well network design and hydrodynamic dispersion. Hydrodynamic dispersion refers to the spread of solute concentrations as they migrate through an aquifer due to variability in pore space and large-scale preferential flow paths.

Key considerations in the design of a production well network for each hydrostratigraphic unit include:

1. Well trajectory; wells were assumed to be vertical (or approximately vertical) in the aquifer and fully penetrate the Leduc and Cooking Lake aquifer.
2. Production-injection well spacing; there is a preference for the injection wells to be distal to the production wells to maximize the life of the production well network before the arrival of low concentrations of lithium in the injected water.
3. Permeability-based well configurations; a close spacing of producing and injecting wells for hydrostratigraphic units with low long-term potential yield in order to increase the production rates.
4. Optimized production-injection volumes and locations; facilitate the maximum recovery of aquifer water production, and strategically distributing the injected water.
5. Geologically based production-injection geometry; a consideration of the geometry of the hydrostratigraphic unit and the properties of the adjacent hydrostratigraphic units.

This NI 43-101 Inferred Resource estimate includes more detailed well network design details for the Wimborne Margin than was considered in the 2017 estimate (see Section 16.8). The additional detail was added to support the evaluation of a Preliminary Economic Assessment. The following sections provide a discussion of the drainage areas and potential well network designs for the four different units in the RA. The Clearwater Interior, Innisfail Margin, and Innisfail Lagoon discussions are conceptual in nature and are presented separately from the Wimborne Margin which underwent more detailed modelling in support of the PEA.

14.3.2 Estimate of Drainage Areas for Units other than the Wimborne Margin

The drainage area represents an area around the production well from which all of the aquifer water would be recovered by the production well if there was no hydrodynamic dispersion. Particle tracking is a modelling technique that tracks the movement of theoretical particles placed in the flow model over time based on the numerical modelling outputs of transient hydraulic head (pressure) and Darcy flux (magnitude of flow rate). Particle tracking provides a physically based estimate of advective transport (fluid movement) and effectively estimates the movement of the advancing injected water front as it moves from the injection well to the production well. As such, it was used to estimate the drainage area of each recovery well network. Groundwater flow and particle tracking was completed in the commercially available finite element software FEFLOW (DHI 2020). The FEFLOW interface was used to simulate particle tracking between the production and injection wells using the following steps:

a. When pumping was initiated, 120 particles were released at different elevations throughout the Leduc and Cooking Lake intervals.
b. The particle locations were followed over time until a particle reached the adjacent wells in the well network.
c. The time of travel between the production and injection well was recorded and interpreted to represent the time that the advective front of the injected water would reach the production well.
d. The extent of all particle migration was used to delineate a drainage area.

14.3.3 Potential Production Well Network Design for Units other than the Wimborne Margin

Because of the net-zero groundwater withdrawal strategy (same volume of water produced as injected), a large rate of groundwater withdrawal can be sustained from a low permeability unit by placing the injection well in close proximity to the production well. While this could sustain high production rates, it would be undesirable for lithium recovery because the injected water (with low concentrations of lithium) would be withdrawn from the production well after a short period of time. This means the effective lifespan of the production well would be reduced.

In order to optimize the trade-off between production rates and the lifespan of production wells, a conceptual level production well network was designed for the Innisfail Margin, Innisfail Lagoon, and Clearwater Interior hydrostratigraphic units and was optimized based on the permeability and geometry of the considered hydrostratigraphic unit.

For the Innisfail Margin, pressure mounding from the injection wells was not required to sustain large pumping rates. As such, only one conceptual injection well was used in the production well network design and it was spaced relatively distant from the conceptual producing well to increase the production life of the well.

A production well network was optimized for the Innisfail Margin, Innisfail Lagoon, and Clearwater Interior hydrostratigraphic units by iterating through the design process in the numerical model in a heuristic manner. It is anticipated that multiple production well networks will be required to produce as much lithium as possible from each hydrostratigraphic unit. The production well networks will be distributed across the resource area. The well networks can be operated sequentially or simultaneously depending on the desired production rates and timelines.

The drawdown associated with large pumping rates from the production well networks is reasonable given the aquifer properties of each hydrostratigraphic unit. In practice, the design and operation of production wells will need to consider the effects of well loss (skin) and pump capacity (ability for the pump and associated infrastructure to move the large water production rates). These factors were not considered to have a substantial impact on the project due to the ability to mitigate these effects by installing additional production wells in close proximity to the simulated production well and due to the preliminary nature of this inferred mineral resource estimate.

14.3.4 Production Well Network Design for the Wimborne Margin

For the purposes of the PEA, further refinement of the Wimborne Margin well network design was completed. The well network design for the Wimborne Margin is discussed in Section 16.8.

14.3.5 Estimated Production from Resource Area

Based on the large available head in the resource area and the flexibility in the well network design, it is expected that large volumes of water can be produced with a relatively small number of wells. It is important to note that the well network design for the Innisfail Margin, Innisfail Lagoon, and Clearwater Interior units is conceptual in nature and that when infrastructure constraints are considered in a more detailed modelling scenario the well networks for these units will require more wells than are currently considered.

Table 14-3. Production well network designs and estimates of production well network drainage areas.

	Resource Area		Reservoir Pressure				Production Well Network Design							
Hydrostratigraphic Unit	Volume (km^3)	Area (km^2)	Hydraulic Head in 1961 (masl)	Hydraulic Head in 2017 (masl)	Top of Leduc (masl)	Available Head (m)	Design Level	Producer Count	Injector Count	Geometry	Spacing (m)	Drainage Area (km^2)	Pumping Rate (m^3/d)	Life of Production Well Network (years)
Innisfail Margin	9	37	850	300	-1500	1800	conceptual	1	2	line	3,000	5	20,000	10
Innisfail Lagoon	6	23					conceptual	1	1	line	3,000	15	20,000	17
Clearwater Interior	242	862					conceptual	1	3	triangle	2,000	18	20,000	10
Wimborne Margin	26	107					detailed	43	21	parallel lines	16,000	79	128,800	20

The evaluation of groundwater production from the potential well networks suggests groundwater in the CCRA can be produced at potentially commercial rates. Table 14-3 summarizes the considered well networks for each hydrostratigraphic unit in the CCRA.

The considered well networks in the Innisfail Margin, Innisfail Interior, and Clearwater Interior, result in water production rates of 20,000 m^3/d with production well networks of one production well and between one and three injection wells. Due to the conceptual nature of these well networks, important factors such as pump capacity and well loss were not considered. It should be noted that more detailed design would require additional wells for these well networks to produce 20,000 m^3/d. The production well networks are predicted to have a life of 10 to 17 years before the injected water reaches the production well (Table 14-3).

The Wimborne Margin well network designed as part of the PEA (Section 16.8) would result in average annual water production rates of 128,800 m^3/d with a production well network comprised of 42 production wells and 21 injection wells. The production well network is predicted to have a life of 20 years before the leading edge of injected water begins to reach the production well (Table 14-3).

14.4 Estimate of Lithium Production

14.4.1 Resource Estimate Methodology

The inferred mineral resource estimate has been prepared to be consistent with the NI 43-101 Standards of Disclosure for Mineral Projects (National Instrument, 2016); Form 43-101F1 (National Instrument, 2011); CIM Definition Standards (CIM 2014); and the CIM Best Practice Guidelines for Reporting of Lithium Brine Resource and Reserves (CIM 2012).

The technical guidance provided in CIM (2012) is focused on the production of lithium brines in salars which is a very different hydrogeologic setting than the deep, confined, clastic aquifers in the CCRA. Examples of the CIM (2012) technical guidance that are not applicable to the CCRA includes:

- A focus on draining the basin (salar) infill which can be unconfined, semi-confined, or confined. Much of the guidance is focused on water released from pore spaces when a water table is lowered (specific yield). The aquifer in the CCRA is approximately -1,500 masl, and is confined with approximately 1,800 m of hydraulic head above the top of the aquifer. Because of the depth and the high pressure, the aquifer will not be drained during the recovery of lithium.
- As described in the guideline (CIM 2012, page 2) salars "tend to be deposited in a typical concentric shell-like sequence from gravel outside, through sand, silt, clay, followed by carbonate, gypsum, and finally halite in the center." The setting results in: "a relatively rapid gradient from near-fresh water to brine" (CIM 2012, page 2); the potential for density driven convection currents; and brine chemistry that can be variable over time based on the water balance. By comparison, the aquifer in the CCRA has a very low salinity gradient, and the water in the aquifer is stagnant (very little flow in or out of the aquifer) because it is approximately 3,000 m below ground surface where the dynamic forces of precipitation, and evapotranspiration at surface do not influence flow in the aquifer.
- "Salar brines are contained within a matrix in which the porosity, permeability, brine composition, and hydrostratigraphic characteristics such as conductivity, transmissivity, anisotropy, and resistance may vary with the passage of time." (CIM 2012, page 4). The hydrogeologic properties of hydraulic conductivity, transmissivity, anisotropy and hydraulic resistance of confining layers, however, are not time variant in CCRA. This is because the water density and the aquifer saturation will not change during lithium recovery.

Although parts of the CIM (2012) guidelines are not applicable to the CCRA, the spirit and intent of the guidelines were applied.

Because of the low lithium concentration gradients and the confined nature of the aquifer, there will be little to no change in brine chemistry over time due to “external (catchment basin) effects” (CIM 2012, page 6). There will, however, be temporal changes due to “internal (extraction induced) effects” (CIM 2012, page 6). Lithium rich water will be pumped to the surface with production well networks comprised of production wells and injection wells. The injected water will be void, or nearly void, of lithium. This will mix with the aquifer water still in the aquifer as it propagates towards the production well. Over time the production wells will begin to pump some of the injected water. This is a key consideration of this inferred resource estimate.

If the production well network was operated indefinitely, the lithium concentration (C) of water pumped from the production well would transition from the initial lithium concentration (C_o) to a concentration that is nearly void of lithium. This is illustrated in Figure 14-7.

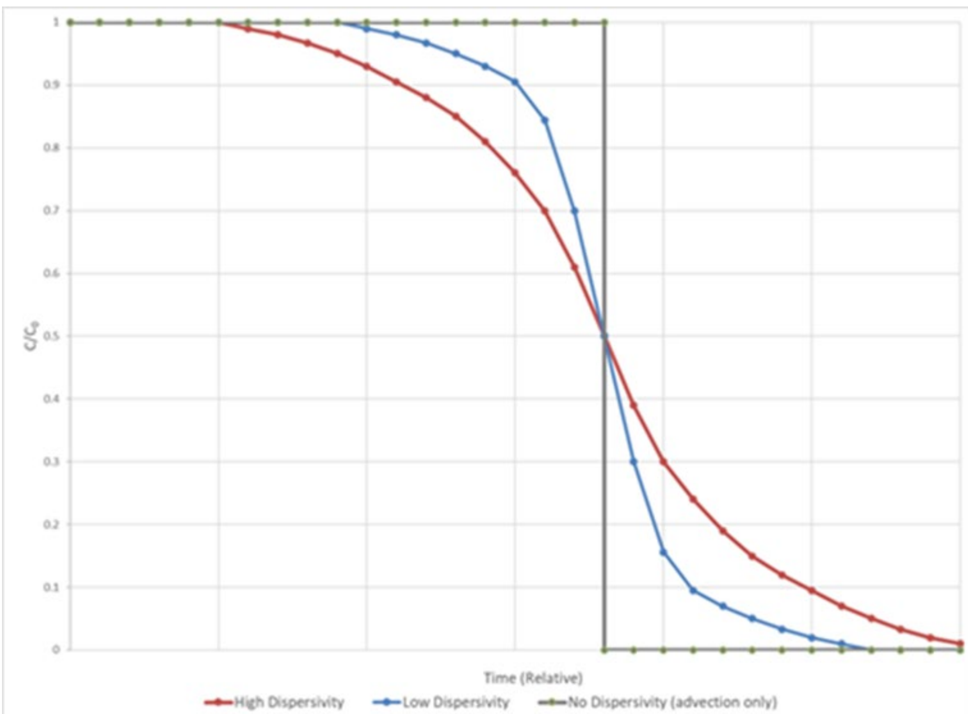

Figure 14-7. Schematic demonstrating the potential relative change in lithium concentration over time at the production well with no dispersivity (gray), low dispersivity (blue), and high dispersivity (red).

The magnitude of hydrodynamic dispersion is a product of the flow velocity (rate of groundwater movement in the aquifer) and the dispersivity (a property of the aquifer). The dispersivity is commonly considered to be a function of scale (Zheng and Bennett, 2002) and aquifer homogeneity (Huang et al., 2012). Predicting the migration of injected water and the change in lithium concentration over time due to hydrodynamic dispersion, requires a high degree of characterization and computational effort considered to be beyond the scope of an inferred resource estimate.

The guidelines (CIM 2012, page 8) state "It is recommended that total porosity and effective porosity are not used for resource estimation since not only is the ratio of total (and effective) porosity to specific yield different for different aquifer materials, but the use of these parameters lead to unrealistic production expectations." As previously stated, specific yield does not come into consideration for confined aquifers that are not being dewatered. As such, in order to honor the spirit and intent of not using the effective porosity in the resource estimation, a production factor cut-off is applied based on the hydrogeologic setting and the expected operation of the production well networks. The production factor cut-off is discussed further in Section 14.4.3.

14.4.2 Lithium Grade

Based on the geologic setting (Section 14.1) and the observed long-term response across the resource area to historical production of fluids (Section 14.2), the Leduc aquifer is judged to be hydraulically continuous within, and beyond, the CCRA. Based on this and the consistency of the lithium assay results obtained from sampling (Section 11), it is reasonable that the lithium concentrations are continuous across the CCRA.

As described in Section 11, Leduc aquifer lithium concentrations were measured at 16 locations within the vicinity of the CCRA and 17 locations in the Exshaw Property in the same contiguous reef as the CCRA. Figure 14-8 shows the location of Li data points with respect to the CCRA. Assuming a similar geological environment for all data recorded in the Leduc aquifer, all 33 data locations were used to build the variogram needed to perform kriging. The variogram is a mathematical representation of the spatial structure identified from the initial data and is used to perform the estimation. A spherical variogram (range of 3,290 m and sill of 14.89 $(mg/L)^2$) and a nugget effect corresponding to 14% of the sill.

Lithium concentration data provided by E3 Metals was obtained from the sampling programs outlined in Sections 9 and 11. A total of 34 water samples from 16 well locations were available in the CCRA (Figure 14-8 and Figure 16-1). The lithium concentration was kriged using the variogram described above and average Li concentrations at 16 wells located in the CCRA. Simple kriging was performed, using the mean Li concentration of 74.6 mg/L for the CCRA as the kriging mean.

The interpolated lithium concentrations in the CCRA range from 71.3 to 81.8 mg/L and have a volume-weighted average of 74.6 mg/L. The interpolated lithium concentrations are relatively consistent throughout the CCRA (Figure 14-8).

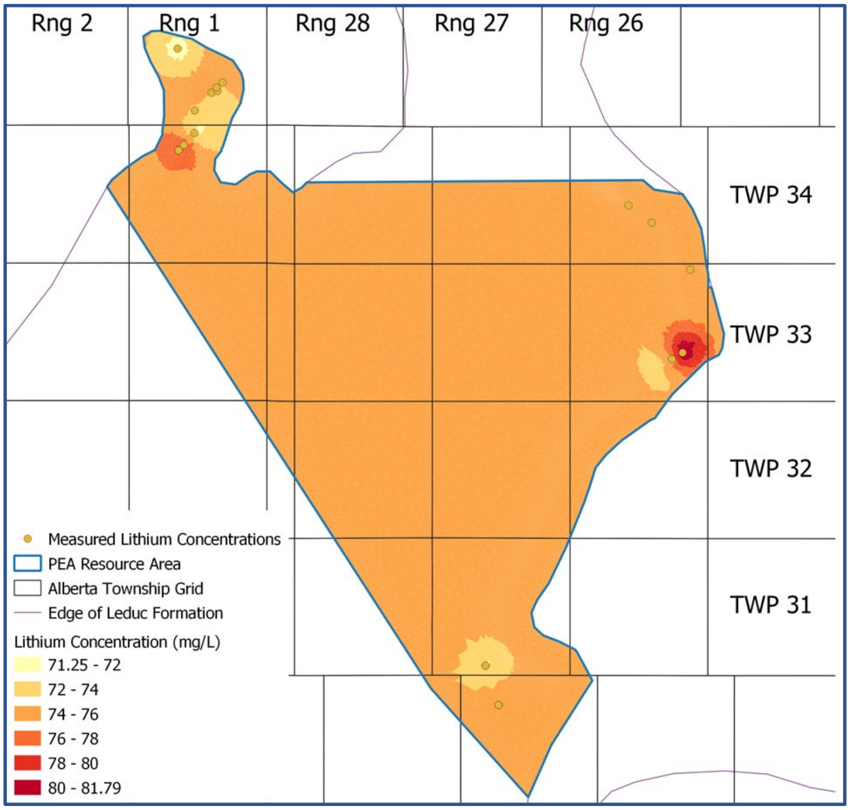

Figure 14-8. Kriged lithium concentrations in the CCRA. Interpolated lithium in the CCRA range from 71.3 mg/L to 81.8 mg/L.

14.4.3 Temporal Effects During Production

The mass of lithium in the CCRA was calculated using the kriged concentrations, the thickness of the aquifers and the effective porosities of each hydrostratigraphic unit. In order to convert the mass of lithium in-place into an estimate of the mass of lithium that can be produced, there are two factors that need to be considered:

1. Hydrodynamic dispersion. The injected water placed back into the aquifer from the processing and lithium extraction will be void, or nearly void, of lithium. This will mix with the aquifer water as it propagates towards the production wells. The mixing results in decreased concentrations of lithium pumped from the production well. Figure 16-11 displays the simulated lithium concentration (mg/L) after 10 and 20 years based on an average annual production rate of 128,800 m^3/day. This is illustrated in Figure 16-11 in Section 16.8, where after 20 years of operation there is a mixing zone approximately 6 km in length on each side of the injected water plume.
2. When producing aquifer water from each hydrostratigraphic unit, it is expected that more than one production well network will be required. The proportion of water that can be produced before the arrival of injected water (low lithium concentration water) will be dependent on the

timing of operations of the multiple production well networks and the distribution of the injected water from previously operated production well networks.

The final production well network design, the timing of production well networks, and the hydrodynamic dispersion of low-concentration lithium injected water, have not yet been determined. For the purposes of this inferred resource estimate, it is assumed that once the concentration of lithium in the produced water drops below the operating cost of the production well network, the production well will be shut-in. This cut-off concentration is referred to as a cut-off grade and is currently estimated to be 50% of the current lithium grade in the CCRA or approximately 37 mg/L. As such, some lithium mass will be left in the aquifer, however, at the time the wells are shut in, the lithium concentration near the injection wells and throughout much of the drainage area may be nearly void of lithium.

Multiple production well networks are expected to be required to produce lithium from each production area. Because the shape of each drainage area will be sensitive to heterogeneity, it is recognized that some lithium will not be captured by any of the production well networks. The amount of lithium that will remain in the aquifer is difficult to estimate, particularly at this early stage of the project, because it will be influenced by design and operation of the production well networks and by aquifer heterogeneities that are not yet characterized.

Based on the two factors discussed above, the mass of lithium in-place was multiplied by production factor cut-offs ranging between 0.3 and 1. A production factor cut-off of 0.5 was selected for the Innisfail Interior and Clearwater Interior hydrostratigraphic units based on professional judgement as a conservative value. With further characterization of the aquifer and optimization of the production well networks, the lithium recovery (and production factor cut-off) in these hydrostratigraphic units may be increased.

The PEA well network design for the Wimborne Margin hydrostratigraphic unit (Section 16.8), results in the recovery of 58% of the estimated lithium present in this production area. This recovery estimate was derived from solute transport modelling and was possible due to the geometry of the unit and the contrasting hydraulic properties from the adjacent Clearwater Interior. It is expected that the percent of recovered lithium in the Wimborne Margin can be increased through continued withdrawal of the PEA well network and by installing additional production wells on the northern and southern edges of the Wimborne Margin in the CCRA. Based on the preliminary well network design for the Wimborne Margin, a production factor cut-off of 0.8 was applied to this production area.

14.4.4 Inferred Resource Estimate

The data sources used for the mineral resource include well data from historical oil and gas operations and brine samples collected from currently operating Leduc wells by E3 Metals. This resource estimate is classified as inferred because geological evidence is sufficient to imply but not verify geological grade, or quality continuity. It is reasonably expected that the majority of the Inferred Mineral Resource Estimate could be upgraded to Indicated or Measured Mineral Resources with continued exploration. Further exploration may include seismic evaluation, a more detailed geological model, and production well testing.

Table 14-4. Summary of the mass of lithium that can be produced in the CCRA for a variety of production factor cut-offs. Lithium mass represents the combined mass of the Cooking Lake and Leduc aquifers.

Resource Area	Volume of Water in Effective Porosity (m^3)	Lithium Grade (mg/L)	Production Cut-off		Production Volume (m^3)	Inferred Lithium Resource Estimate (tonnes)
			Innisfail Interior Clearwater Interior	Wimborne Margin Innisfail Margin		
Central Clearwater Resource Area	9,809,719,564	74.6	1	1	9,809,719,564	730,000
	9,809,719,564	74.6	0.9	0.96	8,952,215,028	670,000
	9,809,719,564	74.6	0.8	0.92	8,094,710,492	600,000
	9,809,719,564	74.6	0.7	0.88	7,237,205,955	540,000
	9,809,719,564	74.6	0.6	0.84	6,379,701,419	480,000
	9,809,719,564	74.6	0.5	0.80	5,522,196,883	410,000
	9,809,719,564	74.6	0.4	0.76	4,664,692,347	350,000
	9,809,719,564	74.6	0.3	0.72	3,807,187,810	280,000

The data in Figure 14-4 can be converted from Lithium metal (tonnes) to Lithium Carbonate Equivalent in tonnes. As a producer of raw materials, E3 Metals will not be able to sell Lithium directly to an off-taker. It is useful for the company to convert lithium to lithium carbonate or lithium hydroxide monohydrate equivalent using the following equations:

Lithium Carbonate Equivalent (LCE), tonnes = Lithium (tonnes) x 5.323

Lithium Hydroxide Monohydrate Equivalent (LHM), tonnes = Lithium (tonnes) x 6.046

The Inferred Lithium Resource Estimate of 410,000 tonnes equates to 2.2 million tonnes of Lithium Carbonate Equivalent (LCE).

14.5 Resource Statement

The two key findings of the mineral resource evaluation include: 1) the determination that high-lithium concentration aquifer water could be produced; and 2) the estimation of the mass of lithium in the net porosity intervals.

The evaluation of the Leduc and Cooking Lake aquifers to produce large volumes of aquifer water was done with a three-dimensional numerical model of groundwater flow. The model incorporated aquifer geometry, porosity, permeability, specific storage, and pressure. The preliminary design of production well networks was tailored to each hydrostratigraphic unit and resulted in large production rates with relatively few wells. In addition, the life spans of the production well networks were estimated using either the numerical model's ability to do particle tracking, or in the case of the Wimborne Margin, the numerical model's ability to do solute transport. Based on conceptual level modeling results, the production rates and life spans of the Innisfail Margin, Innisfail Interior, and Clearwater Interior production area well networks are 20,000 m^3/d with individual production well network life spans of 10 years to 17 years before the injected water reaches the production well. Based on additional analysis completed in the Wimborne Margin a well network of 42 production wells and 21 injections wells can produce 128,800 m^3/d for 20 years with little to no decline in lithium concentrations over that period.

The resource estimate methodology of applying a production factor cut-off was followed because of the plan to inject lithium depleted brine into the aquifer. The methodology recognizes that the re-injected brine will mix with the aquifer water and lithium concentrations in the aquifer will decrease in areas where there is mixing. This approach differs from some published inferred resource estimates (e.g., Eccles et al. 2018) where the re-injection of lithium depleted brine was not accounted for when the inferred lithium resource estimate was made.

After an extended period of production, a proportion of the lithium depleted water that is injected into the aquifer will be produced at the production wells. When the concentration of lithium at the production wells drops below the economic threshold, it is expected that the production wells will be shut-in. Due to the hydrodynamic dispersion of injected water and the expectation that the multiple drainage areas (each associated with a production well network) will not perfectly drain the entire resource area, it is expected that the total mass of lithium in-place cannot be produced. As such, a production factor cut-off was applied to the total mass of lithium in-place to calculate the inferred resource estimate.

The Inferred Mineral Resource estimate for the CCRA is based on the total volume of water in the effective porosity, the interpolated lithium concentration, a 0.5 production factor cut-off for the Innisfail Interior and Clearwater Interior production areas, and a 0.8 production factor cut-off for the Innisfail Margin and the Wimborne Margin. The Inferred Mineral Resource Estimate, expressed as a mass of lithium carbonate equivalent, is 5.5 billion m^3 of brine at 74.6 mg/L, totaling 2.2 million tonnes of LCE.

The resource is classified as inferred because geological evidence is sufficient to imply but not verify geological, grade, or aquifer quality continuity. It is reasonably expected that the majority of the Inferred Mineral Resource Estimate could be upgraded to Indicated or Measured Mineral Resources with continued exploration.

15 Mineral Reserve Estimates

Not applicable.

16 Mining Methods

For the Clearwater Lithium Project, lithium is sourced from the production of brine water from deep vertical or deviated wells into the Leduc aquifer. This brine will be transported to the Central Processing Facility (CPF) via underground pipelines where lithium will be extracted from the brine water. Lithium void brine is then returned to the Leduc aquifer through deep vertical or deviated injection wells. There are no surface mining methods utilized for this project as the brine is pumped from the aquifer and returned back into the aquifer after lithium removal, within a closed-loop system. Primary extraction and the recovery of lithium is achieved through direct lithium extraction methods developed by the company and described in detail herein.

16.1 Overview of Project Area Wells

Within the project area, over 7,000 wells have been drilled through the exploration development and production of hydrocarbons and water. Approximately 1,000 of the wells have intersected the target aquifer (Leduc aquifer) or deeper. There are three mature oil and gas fields in the Leduc aquifer north and south of the target area. All these oil and gas fields have utilized the proven method of fluid recovery via subsurface wells. The map below shows the Leduc hydrocarbon production and water disposal wells in the project area. The map highlights in yellow the Leduc oil and gas production wells; in blue the Leduc water disposal wells; and the green bubbles to show the range of cumulative oil production.

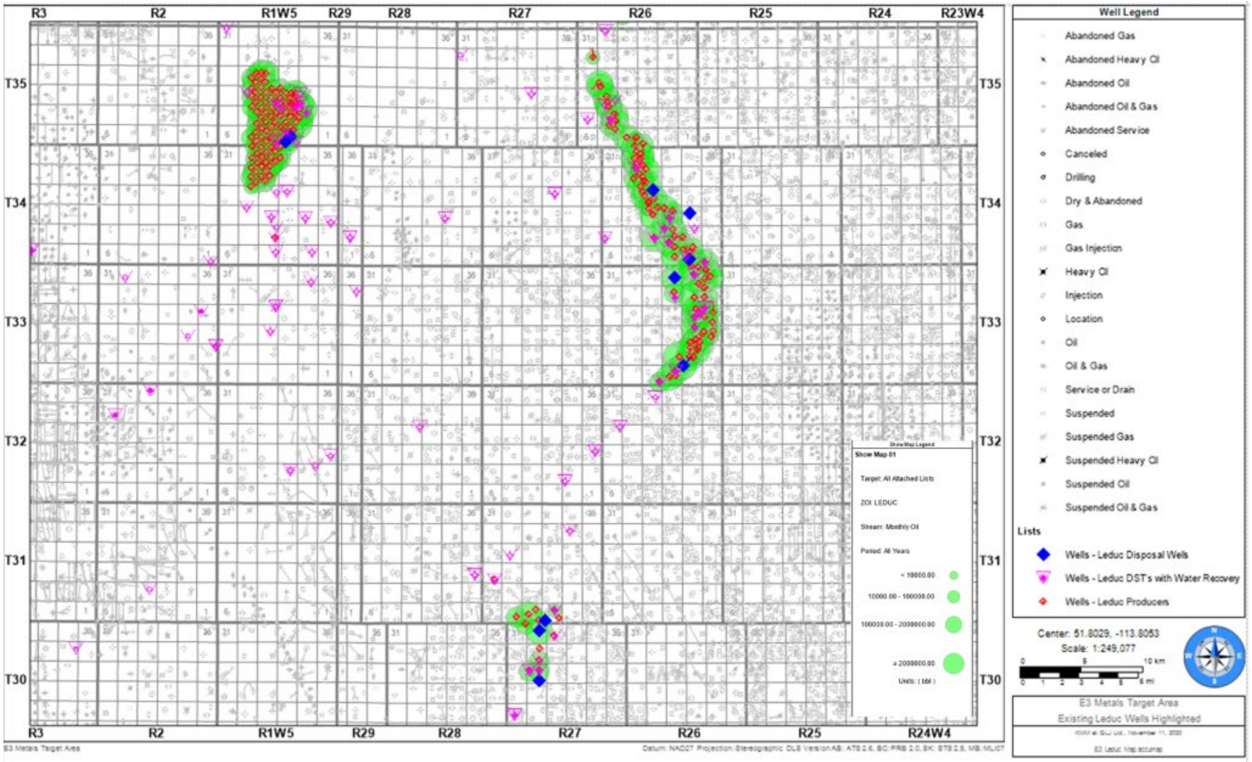

Figure 16-1. E3 Project Area Leduc Wells (Accumap^{TM}, 2020)

Hydrocarbon production from the Leduc in the Resource Area started in the 1950's and has continued to present from primarily three major pools highlighted in green on the map. There are only minor amounts of hydrocarbon production today relative to the historic volumes produced. Within the project area, the total production is $19e^6m^3$ oil, $60e^6m^3$ water, and $14e^9m^3$ gas from approximately 200 wells (Section 6.4). The total water disposal into the Leduc is $62e^6m^3$ in the three pools.

A plot below shows the water injection rates in the project area into the Leduc aquifer. Peak fluid injection rates are higher than 10,000m^3/d which supports the brine disposal rates proposed in this section.

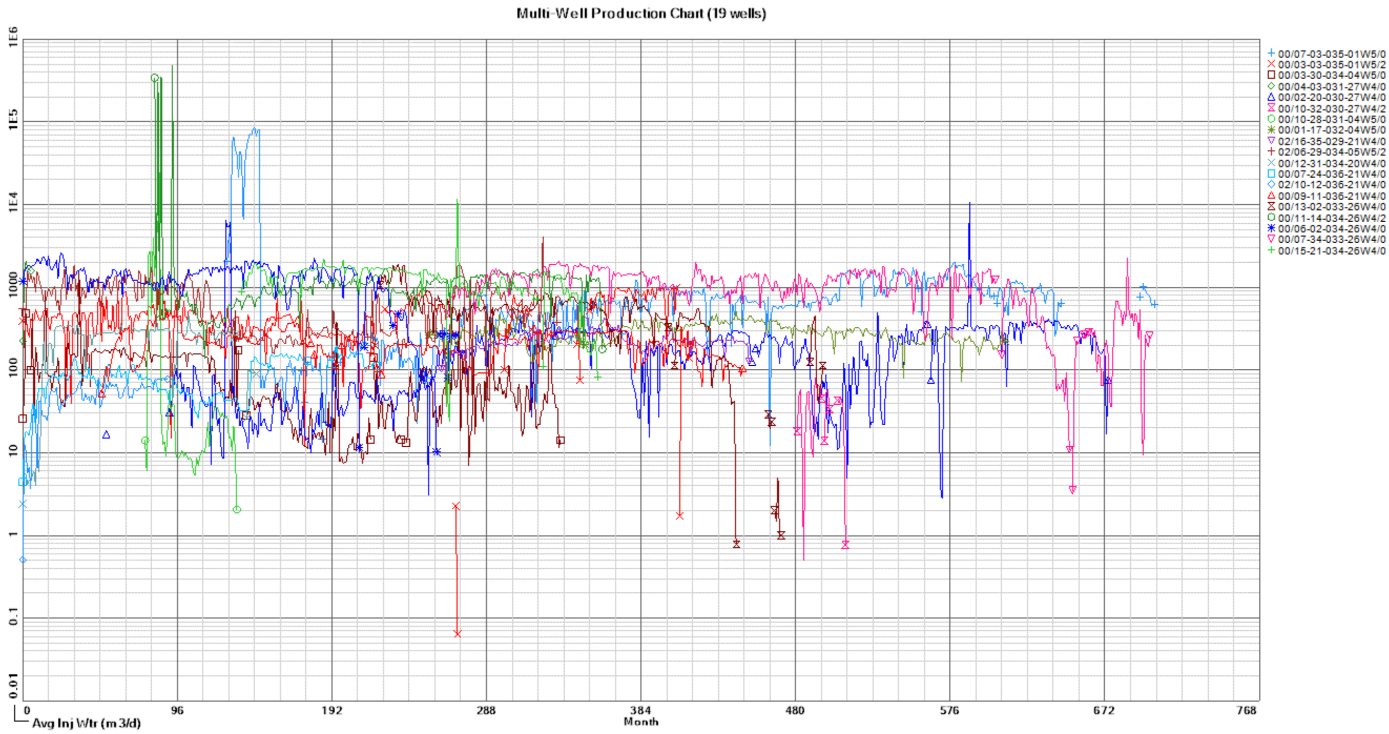

Figure 16-2. Normalized production of Project Area Leduc Wells (Accumap™, 2020)

Shown below are several examples of Leduc disposal wells where the typical water injection rates are 1,000-2,000m^3/d. Acid squeezes, indicated by orange lines, are a common maintenance service required for maximum uptime (operating hours) of the injectors in the Leduc. An acid squeeze removes build-up of scale or fines that block injectivity. This type of treatment is most often required when fluids of different chemistries are injected into a subsurface aquifer, resulting in adverse chemistry interactions. Because the injected brine chemistry will be very similar to the aquifer brine chemistry, the requirement for acid squeeze maintenance is expected to be less than the examples shown here.

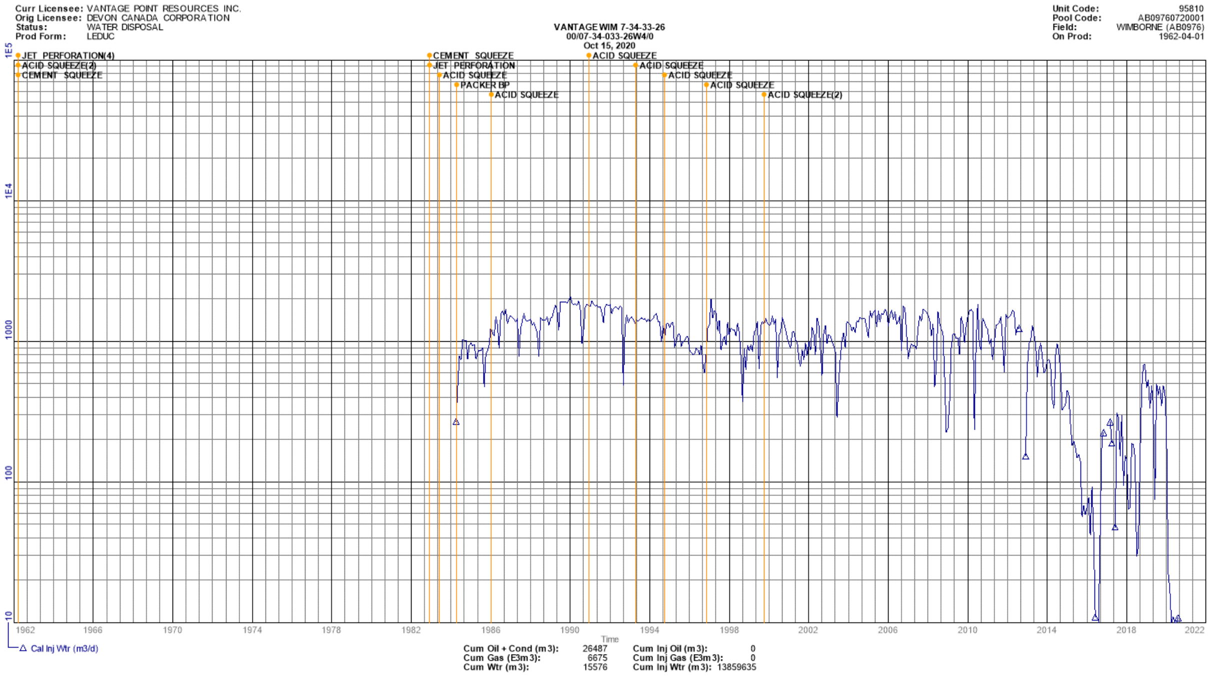

Figure 16-3. Disposal History of 100/7-34-33-26W4M/00 (Accumap™, 2020)

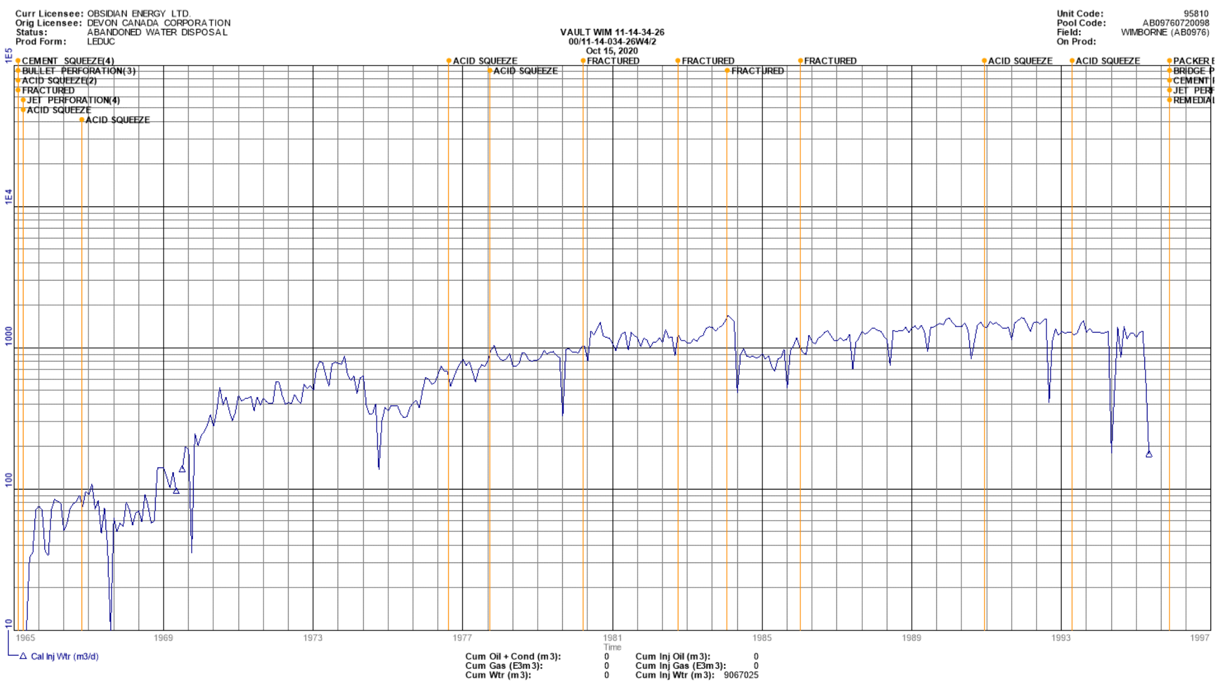

Figure 16-4. Disposal History of 100/11-14-34-26W4M/00 (Accumap™, 2020)

16.2 Well Design Considerations

Vertical and deviated wells are required for production and injection. Most of the existing wells in the project area are developed as one well from one surface pad. For this project, consideration is given to environmental and surface land use to minimize disturbance and optimize capital costs. Therefore, the development plan is to place multiple wells from one surface pad, referred to as a multi-well pad. This allows for the centralized gathering of fluids and reduced road and pipeline construction. The bottomhole well placement is defined based on the aquifer modeling and assumes spacing between the bottomhole locations. With these targets in mind, the well pads are planned with a series of vertical to directional wells with varying degrees of deviation. This is a common drilling practice utilizing special tools for directional drilling. Below is a diagram showing variations of directional drilling well (hole) displacement. There are no plans for horizontal wells for this project, as they would not provide sufficient vertical coverage for optimized brine recovery from the thick Leduc aquifer.

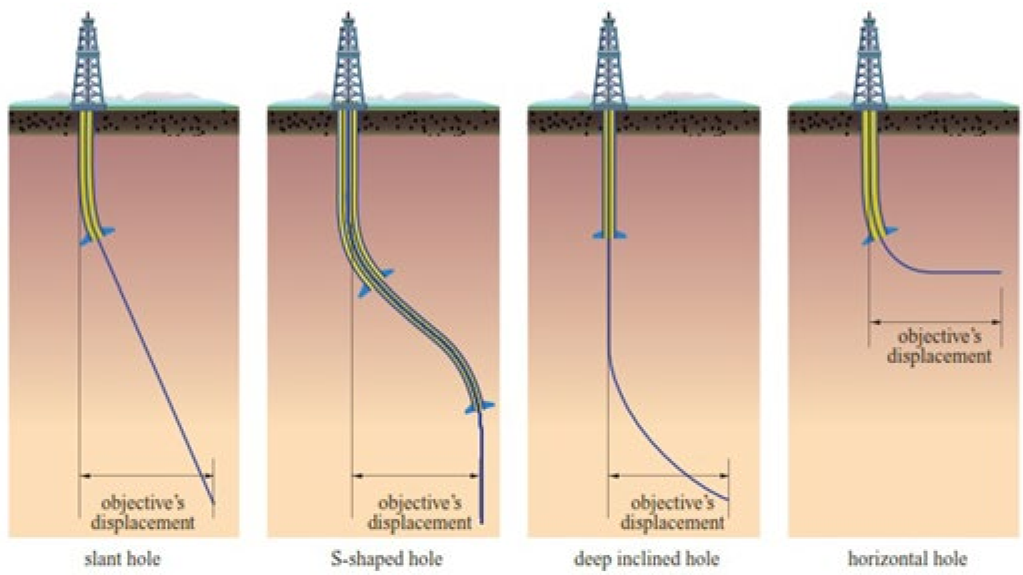

Figure 16-5. Conceptual diagram of directional well (hole) displacement (Ref: energydais.com)

Drilling wells for brine production and injection uses the same practices and proven technology as oil and gas well drilling. The assessment of the total drilling depth to the bottomhole target aquifer, size of the wellbore, and learnings from wells drilled in the project area, has resulted in an estimation of expected drilling time of 26.5 days per well. The time to drill a well is typically referred to as 'spud to rig release', which refers to the time the well is initiated through to the time the drilling program is finished. For the total well program of 42 brine production wells and 21 water disposal wells, the drill program will require approximately 1,700 days of drilling. With a four-rig program, this could take 12-14 months of drill time. Before drilling starts, civil construction is required for the construction of well pads and road access. This also needs to be considered in the well program schedule.

There are potential optimizations that could reduce the per well drill time, which are dependent on the final location of each well and total depth expected. Further, there is opportunity to improve the overall project schedule by planning for concurrent execution of major field activities. This overlap can shorten the total well installation program schedule.

16.3 Multi-Well Pad Development Plan

Based on the location of the Leduc aquifer (aquifer) for brine production and disposal, as described in Section 7 of this Report, a development plan is recommended that utilizes multi-well pads with wells drilled using directional drilling technology to achieve bottomhole targets from the one well pad location. The figure below shows the location of the three pad areas, with production wells north and south of the injectors, at 15-16 km between producers and injectors. Table 16-1 summarizes the recommended well development plan.

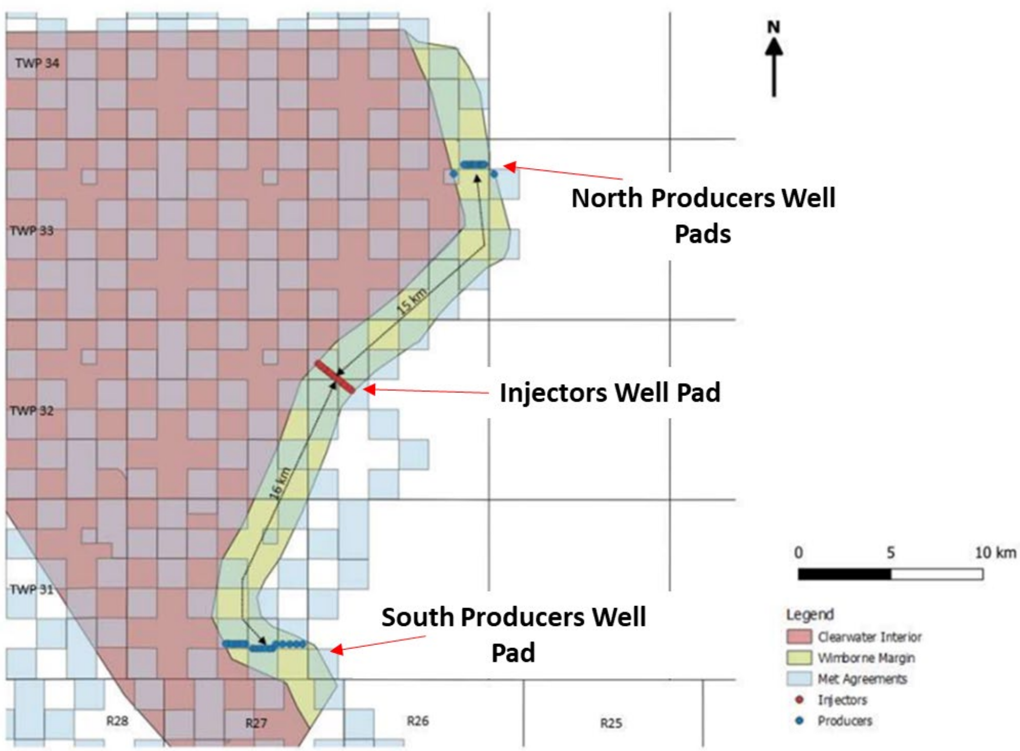

Figure 16-6. Project Area Well Pad Proposed Placement indicating bottomhole locations.

Table 16-1. Proposed Multi-Well Pad Development Plan

	North Producers	South Producers	Injectors
Number of Wellpads	2	2	1
Number of Total Wells	21	21	21
Surface Well Spacing (m)	8	8	8
Well Spacing at top of Leduc formation Bottomhole target (m)	40m-80m	80-750m	105m-140m
Directional Build Angle - inclination	3 deg/30 m with max 27-30 deg	3 deg/30 m to 5 deg/30 m with max 45 deg	5 deg/30 m with max 45 deg

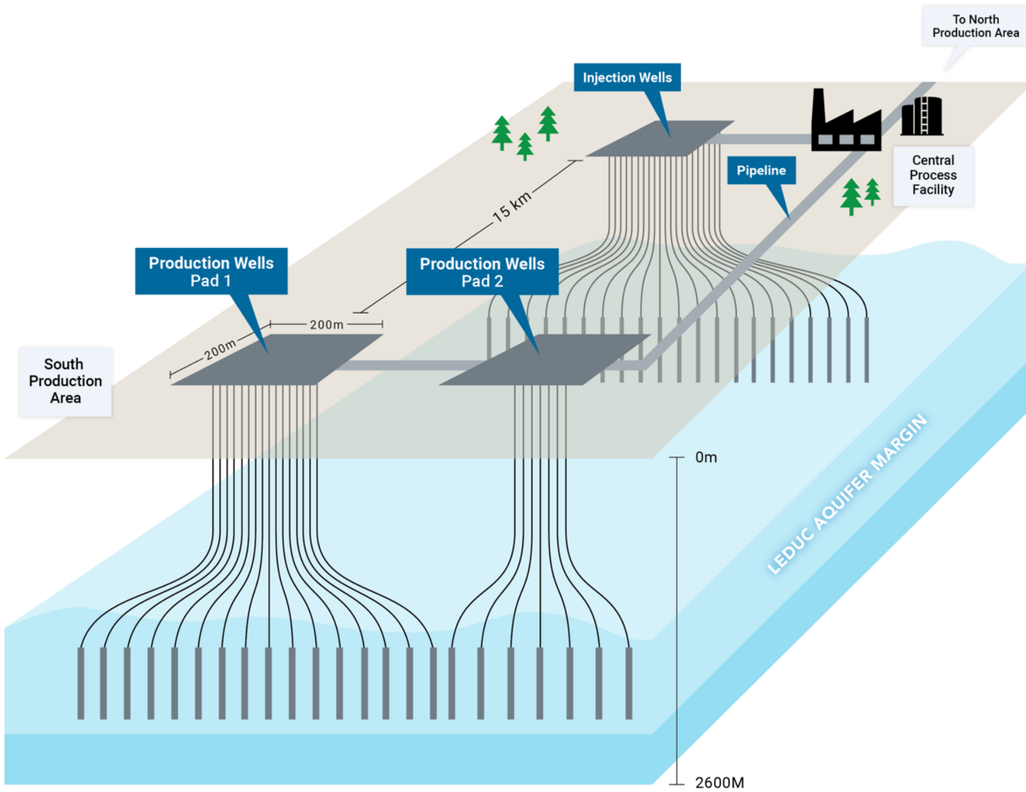

Figure 16-7. Schematic showing E3's proposed multi-well pad layout at the south producer and injector area (north producer wells not shown)

16.4 Well Integrity

Well integrity is a risk management program that manages the safety of the well with respect to Health, Safety, and the Environment (HSE). The program starts with the installation of the well, plans for the operational life of the well, and then the abandonment. The initial part is the well drilling program, which includes cementing of each string to ensure mechanical protection of groundwater and flows to surface, from the target aquifer or any zone contacted by the wellbore.

The cementing of the surface casing, intermediate casings, and other casing strings installed is done once the drilling of each is complete, to set the pipe in the drilled hole. The cement type is based on many variables including but not limited to the expected production/injection rates, zones contacted by pipe, temperature, cycling, sour service, etc. The type of cement used for well drilling operations is similar to cement used for civil construction, with additives as needed depending on expected downhole conditions for temperature, salinity, or type of operations expected. The cement sheath between the pipe and the rock provides the protection needed for corrosion protection of the pipe, and for zonal isolation between zones and to surface.

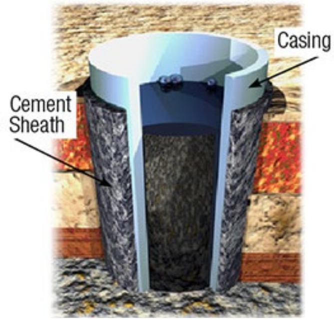

Figure 16-8. Example of cemented casing strings and cement sheath (Ref: 3m.com)

16.5 Subsurface Brine Production

The lithium enriched brine in the Leduc aquifer is produced through the subsurface wells to surface, using a downhole pumping system. The pumping to surface is referred to as ‘Artificial lift’, which is required to overcome the weight of the water column to surface, even with the support of the aquifer flowing pressure. The pumping system planned for this project is Electrical Submersible Pumps (ESP). They are commonly used where large fluid volumes are pumped for industrial purposes, including oil production and geothermal operations.

The pumps consist of multiple centrifugal pump stages mounted in series within a housing attached to a submersible electric motor. Each stage contains a rotating impeller and stationary diffusers typically cast from high-nickel iron to minimize abrasion or corrosion damage.

Power is 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 is banded or clamped to the production tubing. A step-down transformer converts the electricity provided via commercial power lines to match the voltage and amperage requirements of the ESP motor.

An inflow performance curve (IPR) is generated for each pump manufactured and quantifies the relationship between pump horsepower, efficiency, flow rate and head relative to the operating flow rate. The pump recommended operating range is defined for each pump stage in the catalog performance curve, but this can be optimized and better understood for each well when it is in operation. Predictive analysis is done to evaluate performance, optimize operating conditions and prepare for pump failures.

The ESP design planned for this project will move the brine from the Leduc aquifer depth of over 2500m to surface and maintain sufficient pressure to flow into the gathering pipeline system to the central Lithium recovery facility. The pumps are set above the producing interval, based on the expected aquifer flowing pressure and rate. The fluid from the producer wells will have sufficient pressure to flow directly to the Central processing facility (CPF), with metering on the multi-well pad facility. The selected Pump size is 171.45 mm (6.75”) and are 1,029 Horsepower with a discharge pressure of 17,886 kPa.

The multi-wellpad design for this project assumes multiple deviated wells from one surface pad. The degree of inclination must be considered when planning for the ESP placement in the well. Although ESP systems can operate at 0° to 90° inclinations, their application is restricted by the well curvature through which they must pass during deployment and landing. ESP manufacturers must use dogleg severity (a measure of hole deviation change per meter) to determine the stress and deflection of the ESP components to ensure proper installation and operation is possible.

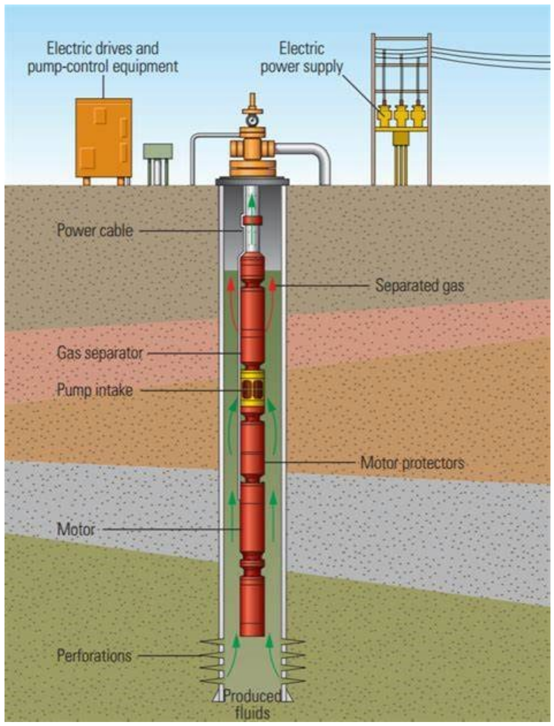

Figure 16-9. Example Electrical Submersible Pump (ESP) equipment placement[12]

16.6 Aquifer Management Considerations

The subsurface brine recovery system is based on balancing the pressure decrease created from water production with a pressure increase created from water injection (a net-zero withdrawal strategy). With injection planned in the middle of the production well arrays, a sweep effect is expected where pressure increase at the injectors will increase pressures and sweep aquifer water toward the brine production. During early production there will be some depletion effects near the producers. Once sufficient volume has been injected to create the pressure front and sweep effects, pressures will reach a nearly steady-state.

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[12] *worldanalytics24.com*

16.7 Well Design Scenarios and Cost Estimation

Six drilling and pump design cases were evaluated to determine the optimal well design based on the deliverability, total project cost for drilling, completion and equipping with pumps. The primary factor was achieving an efficient cost basis while delivering a total brine production of 128,800 m^3/d from a network of multiple wells. This evaluation investigated the injection capacity, with well deliverability based on subsurface pump design as the critical factor. Each case assumes a different pump size which then determines the size of casings and the drilling costs.

16.7.1 Drilling, Completion, and Pump Costs

The drilling cost per well is determined by the hole size to fit the appropriately sized casing and is measured from spud of well to rig release in days, referred to as “drilling days” for this Report. For this project it is assumed that all wells (producers and injectors) will have the same hole size and same casing configuration, with exception of the completion across the aquifer, which may vary for producers and injectors. The casing grade specifications will be the same for the injectors and producers and is assumed to take sour service into account, to be conservative in the design for corrosion prevention.

In addition to the cost of drilling rig, the drilling cost includes many different types of equipment and services that are part of the drilling process such as logging, cementing, drilling fluids, and tubulars including casing and production tubing . The total cost of each well also includes a portion of the civil construction of the wellpad, and an allocation for the costs of mobilization and demobilization of the rig. The wellpads are assumed to be multi-well and depending on the location in the south or north for producers, or for the injectors, will accommodate up to 21 wells per pad.

The completion of the well is the cost of equipment and services utilizing a completion rig to run the internal production strings, including a liner across the production interval and the production wellhead. The cost for the subsurface pump (Electrical submersible pump – ESP) includes the surface equipment needed for electrical supply to the downhole pump and instrumentation.

The same applies to the injector wells, with the same assumed drilling and completion design. The only difference is there is that there is no ESP. As the pump is a horizontal surface pump, the cost is estimated by SCOVAN as part of the surface facilities.

Based on the evaluation conducted, a drill hole with a production casing size of 200 mm (7 7/8 inch) and a production tubing size of 139.7 (5 ½ inch). This utilizes a Baker Hughes electric submersible pump (ESP), with an expected production rate of 3,300 m^3/d/well. Therefore, a total of 39 production wells is required to meet the brine production rate of 128,800 m^3/d, with three additional production wells planned for redundancy. The average drill, complete and pump cost per production well is CAD 2.96M. It is assumed that the injectors will have an injectivity rate of 6,600 m^3/d/well. This means a total of 20 injectors are required to dispose the produced brine, with an additional injection well for redundancy.

Drilling all the wells is expected to take over a year for all 63 wells, based on 26.5 drilling days per well. For this estimate it is assumed that 4 rigs would be used to complete the program. The total drilling days are 1,700, but with 4 rigs this brings the program down to 417 days. Consideration is needed in the project schedule for civil pad construction and access roads prior to the start of drilling. As well, pipeline and surface facility construction, and site clean-up after construction needs to be added following drilling and completion of the wells. Optimizations of this schedule are possible by running concurrent operations to streamline drilling and completions at the same time on one pad, allowing for earlier start-up of some wells.

The capital spend for the well program will extend over 1 to 2 years, depending on the efficiency that can be gained with concurrent operations, number of rigs, and accommodating spring break-up or environmental restrictions.

16.7.2 Well Operations Cost Estimation

The operation of the brine production wells is very similar to that of oil wells in the project area. In fact, many wells in the area produce mostly brine from the Leduc aquifer today in comparison to hydrocarbon by volume. Hydrocarbons are not expected to be present in the brine production for E3's project. Many of the cost factors are similar though, which include fixed costs for the maintenance of the roads and well pads, surface land rentals, property taxes, insurance, well servicing, fluid sampling/analysis, waste management, security, and operations staff. The variable operating costs are related to brine production and typically include electricity costs for pump operation, or chemicals. Chemicals will be required for corrosion inhibition and scale prevention.

The ESPs selected are estimated to have a pump life of 2.75 years. Pump replacements are a cost that is expected in every year of operation, and depending on the situation, can be capital expense or operating expense. 42 ESPs planned to maintain 128,800 m^3/d brine production rate, including 3 wells for redundancy, with an average failure rate of 1 every 2.75 yrs. It is therefore expected that there will be failures in Year 1 and every year thereafter. The percentage of failures in the first years of operation will be less than the average failure rate but it is difficult to estimate since it is dependent on the operational conditions of this project. The cost for each pump replacement is assumed to be 80% of the initial cost, which is CAD 550,000 per ESP. The Initial cost of CAD 690,000 per pump includes surface equipment associated with electrical delivery to pump and instrumentation.

Well servicing (workovers) may be required for the production and injection wells. The Leduc water disposal wells that have operated historically in the project area have required frequent acid stimulation/soak jobs to mitigate loss of injectivity. Impairments to injectivity are typically due to blockages in the aquifer near the wellbore or open hole completion, sometimes referred to as skin factor. The blockages can be a result of scale buildup from geochemical reactions, or buildup of fine particles that cause flow impairment. Both these types of impairments can be removed or reduced with acid. Typically, hydrochloric acid is used, but other acids may be applicable, depending on the source of the flow impairment and compatibility with the aquifer fluid. The cost to implement this type of workover will vary depending on the need for a rig, acid used, type of injection needed or other factors and has been included in the cost estimate.

16.8 Aquifer Management Plan

The selected well network, and its associated infrastructure, is designed to be capable of producing 140,000 m^3/day over a 20-year period. The average annual brine production rate required for the production of 20,000 tonnes of lithium hydroxide is 128,800 m^3/d and represents 11,200 m^3/d of redundant brine production capacity accounting for a 92% operability factor. The distance between each production well network and the injection well network was also designed such that the lithium void brine from the injection wells would reach the production wells after 20 years and achieve a maximum dilution of 5%.

A well network with two production well groupings consisting of 21 wells at each grouping, located north and south of the CPF. One injection well grouping consisting of 21 wells is located proximal to the CPF elected (Figure 16-10). The line of injection wells is located approximately 15 km and 16 km away from the line of production wells to the north and south, respectively. The well spacing in the north and south production lines is variable and ranges between 40 m and 743 m. Similarly, the spacing between injection wells is also varied and ranges between 103 m and 140 m. The variable spacing between wells was selected heuristically based on the metallic and industrial minerals leases owned by E3 (Figure 16-10) and, to a lesser extent, the thickness of the resource.

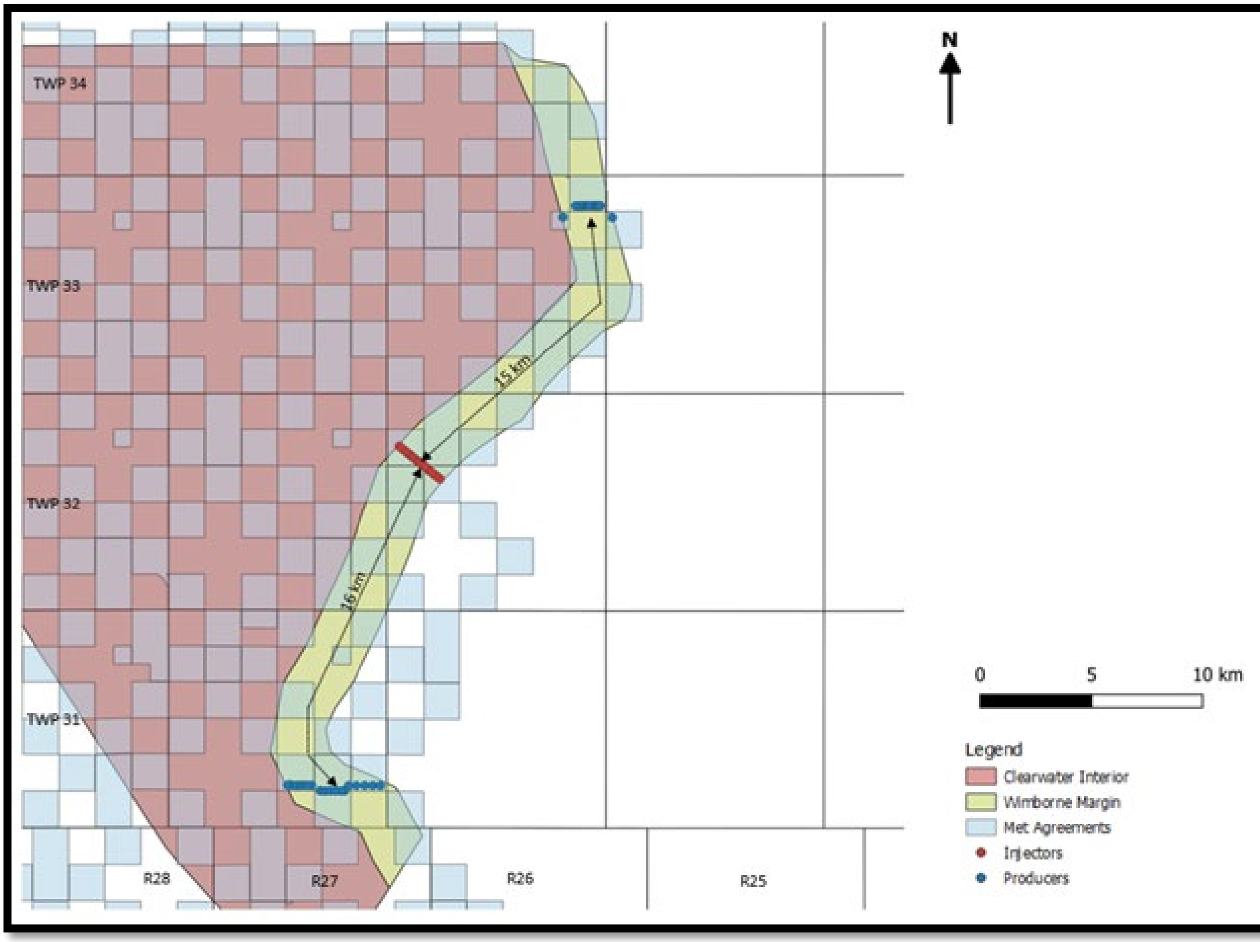

Figure 16-10. Wimborne Margin Well network design. Location of water supply wells and injection wells.

Figure 16-11 shows isolines of lithium concentration 10 years and 20 years after pumping/injection was initiated. Lithium-depleted groundwater from the injection wells is predicted to start reaching the production wells after approximately 20 years (Figure 16-11). During this 20-year operating period, lithium rich groundwater was depleted in a 79 km^2 area of the Wimborne Margin (area of Wimborne Margin between the north and south lines of production wells).

Figure 16-11. Simulated lithium concentration (mg/L) after 10 and 20 years based on an average annual production rate of 128,800 m^3/day.

The largest drawdown (decrease in pressure) due to the brine withdrawal is predicted in the vicinity of the production wells. Brine mounding extends within the Wimborne Margin from the line of injection wells to the south and north production wells and laterally to the Clearwater Interior. After 20 years of operation, the maximum predicted drawdown at the production wells was approximately 135 m and the maximum predicted mounding at the injection wells was approximately 284 m.

17 Recovery Methods

17.1 Introduction

E3 Metals Corp. has developed an Ion Exchange (IX) sorbent material that is highly selective for lithium. It is capable of selectively concentrating low concentration lithium brine solutions from 74.6 mg/L to >850 mg/L Li^+, while simultaneously rejecting the bulk of other metallic ions present in the brine (such as Na, Ca, Mg etc.).

E3 Metals Corp. has proposed a Direct Lithium Extraction ("DLE") process centred on their core IX technology to extract lithium from the Leduc Aquifer in Alberta to produce 20,000 t/a Lithium Hydroxide Monohydrate (LHM, $LiOH.H_2O$) for use in lithium-ion batteries.

The general concept of E3 Metals Corp.'s DLE process is shown schematically in Figure 17-1 below.

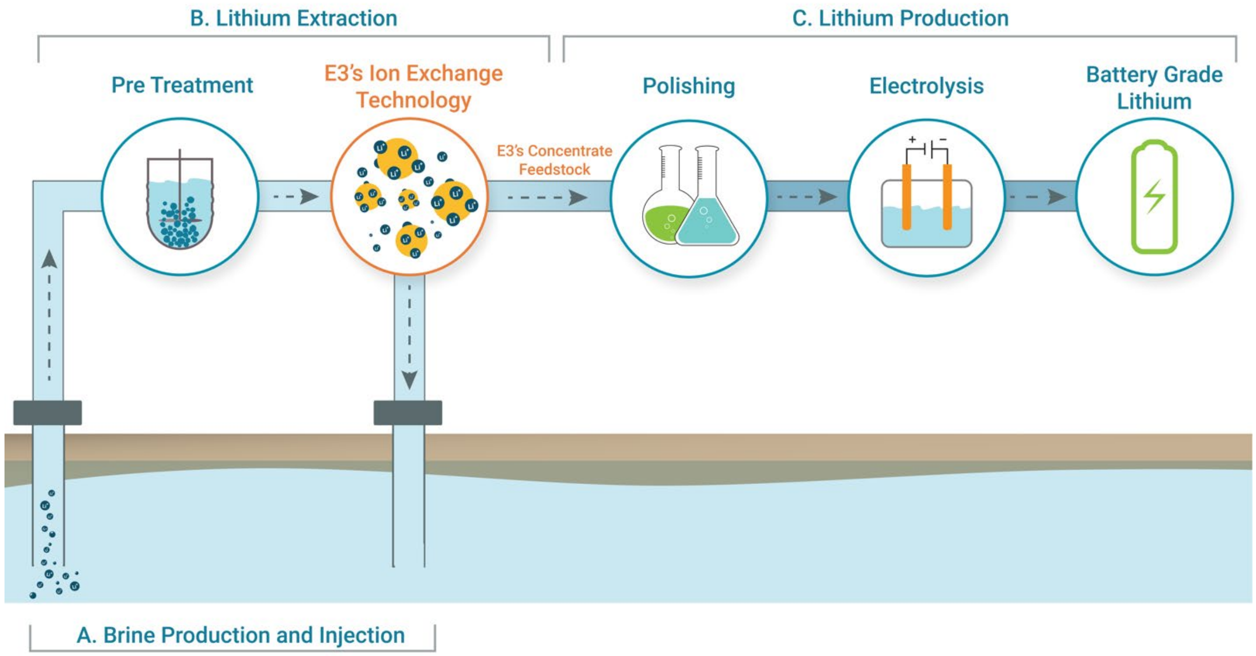

Figure 17-1. E3 Metals' Concept Block Flow Diagram for Lithium Extraction from the Leduc aquifer (E3 Metals Corp, 2020)

NORAM has developed a preliminary flowsheet for polishing and processing E3's concentrate feedstock to produce Lithium Hydroxide Monohydrate ("$LiOH.H_2O$" of "LHM") after extraction and pre-treatment of the feed brine. Although it is possible to produce Lithium Carbonate ("Li_2CO_3") through crystallization from the purified lithium concentrate, this Report contemplates only LHM production.

There is an implicit assumption that the proprietary IX sorbent material, which has currently been tested in several forms, will be suitable for the bulk mixing, adsorption and rapid settling required for a "resin in pulp" type counter current circuit. Alternately, it might be formulated into a material which can be used in a fixed bed environment.

The process design presented in this Report appears to be technically feasible but has not yet been proven at a commercial scale or optimised in terms of process operating envelope. The flow sheets presented in Figure 17-3 and Figure 17-4 show how the E3 ion exchange technology might be implemented on a commercial scale.

As with any new process, it is critical that, once a preferred flowsheet is identified, it is taken through each stage in the lab, and then at pilot scale. This will highlight any unexpected performance issues related to trace elements or other aspects of the chemistry which are not easily predicted by desktop study. E3 has committed to advancing towards process scale up to pilot as a high priority.

17.2 Process Design Summary

The preliminary process design is based on the production of 20,000 tonnes per year lithium hydroxide monohydrate ("LiOH.H_2O" or "LHM") using E3's proprietary ion exchange (IX) sorbent material, which requires processing of approximately 5,833 m^3/h of 74.6 mg/L feed brine. The concept process is shown in block diagram form in Figure 17-2 and is estimated to recover ≥94% of lithium in the feed brine and reagent recycle, producing approximately 2.48 t/h LiOH.H_2O.

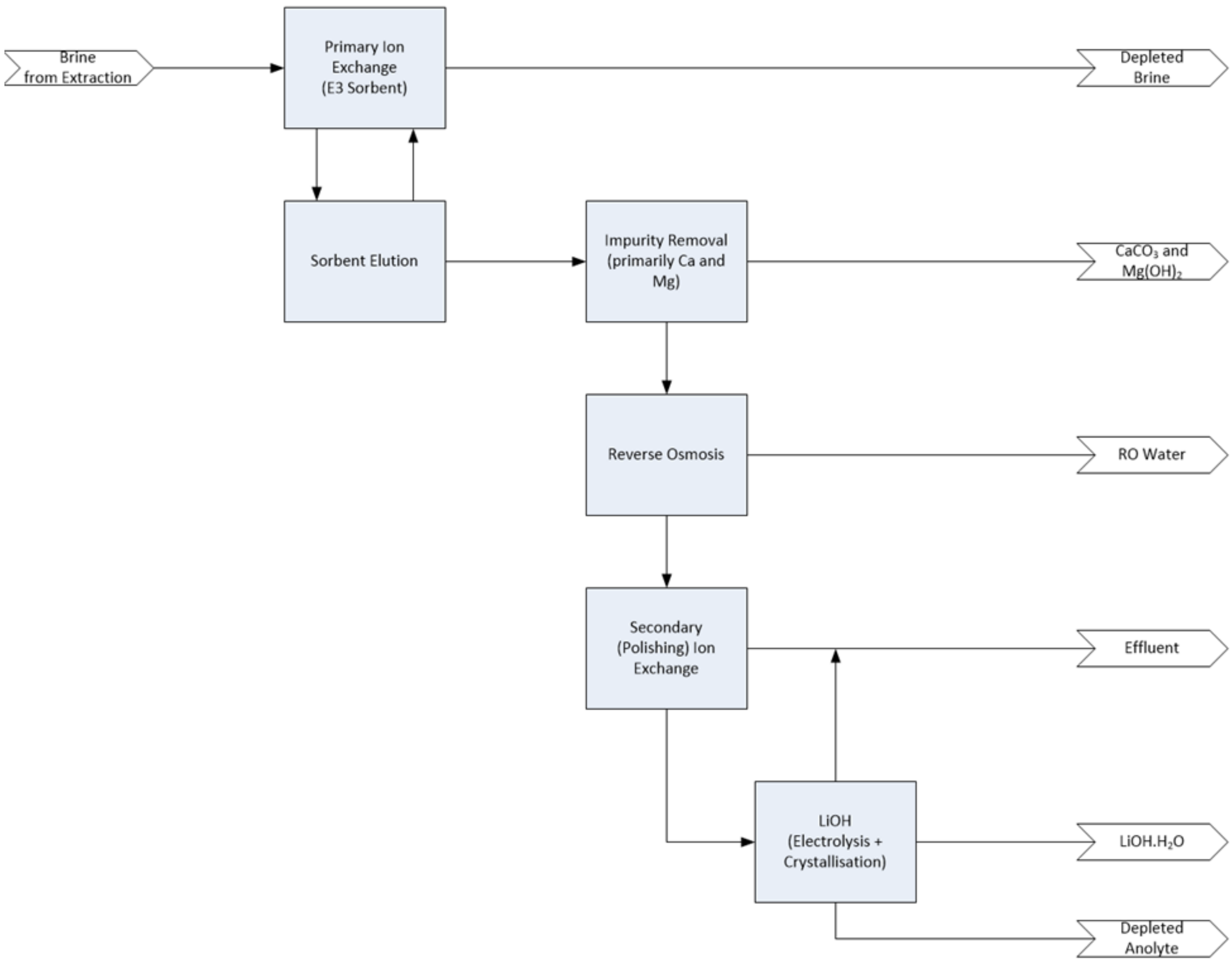

Figure 17-2. Block flow diagram of lithium extraction, polishing and LHM production process.

17.2.1 Primary Lithium Extraction

The feed brine is contacted with and absorbed onto E3's proprietary sorbent material in a series of "ion exchange" vessels, similar in configuration to a standard Resin-in-Pulp or Carbon-in-Pulp circuit commonly employed in the hydrometallurgical industry. The lithium is stripped from the loaded sorbent using anolyte recycled from the electrolysis circuit while the depleted lithium brine is returned to the well field for re-injection into the aquifer.

17.2.2 Polishing of Lithium Concentrate

The primary ion exchange process provides significant concentration of lithium over the other cations in the feed brine, containing approximately 870 mg/L Li^+ (concentrated from the 74.6 mg/L in the feed brine).

When the sorbent is stripped, any cationic impurities remaining on the sorbent are eluted into the sulphuric acid together with the lithium. The bulk of these metal impurities in the stripped liquor (primarily Ca^{2+} and Mg^{2+}) are precipitated using Li_2CO_3 and LiOH from the approximately 500 m^3/h of eluate. Lithium based reagents were selected instead of sodium-based reagents for the primary polishing step as these reagents could be internally produced and recycled significantly reducing reagent costs. This does not lead to any significant lithium losses.

17.2.3 Concentration of Purified Concentrate

The purified brine is then further concentrated to approximately 14,000 mg/L Li^+ in a reverse osmosis ("RO") circuit, with the produced RO water either used in the process as make-up water, returned to the well network or exported to other users. Calcium and magnesium are removed to even lower levels in a secondary, polishing ion exchange circuit (using standard ion exchange resins) prior to electrolysis

17.2.4 Electrolysis of Lithium Concentrate and Crystallization of Lithium Hydroxide Monohydrate

Lithium hydroxide monohydrate (LHM) is produced in an electrolyser where the ultrapure brine is electrochemically split to produce LiOH (and NaOH). The LiOH/NaOH product from the electrolyser is crystallized and separated in a crystalliser with washing centrifuge(s) and dried to produce final, dry $LiOH.H_2O$ (LHM) crystals.

17.3 Block Flow Diagrams

17.3.1 Primary Extraction and Polishing

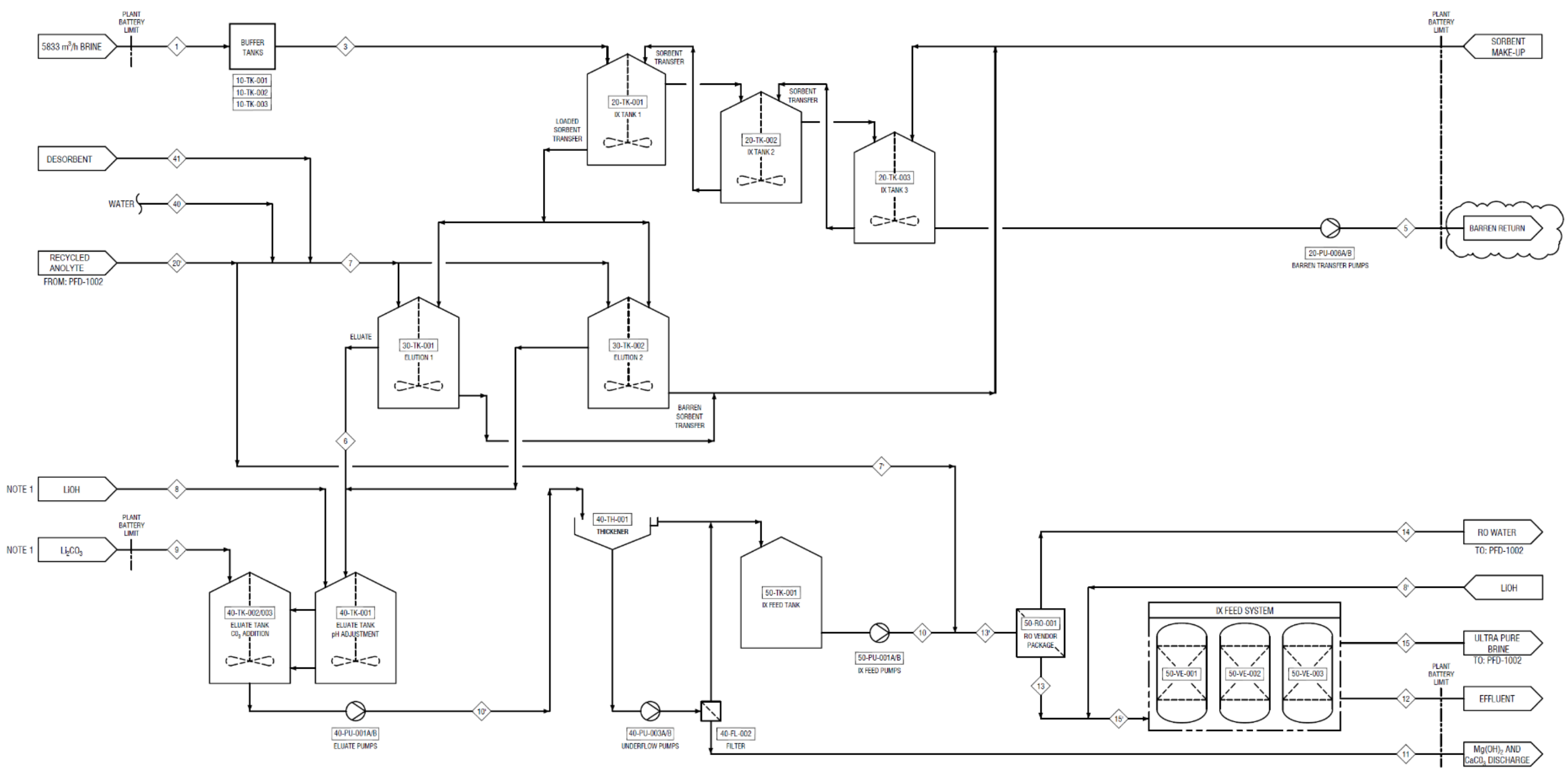

Figure 17-3. Preliminary block flow diagram of primary lithium extraction and polishing process to producing a concentrated, ultra-pure lithium brine (PDF-1001)

17.3.2 Electrolysis

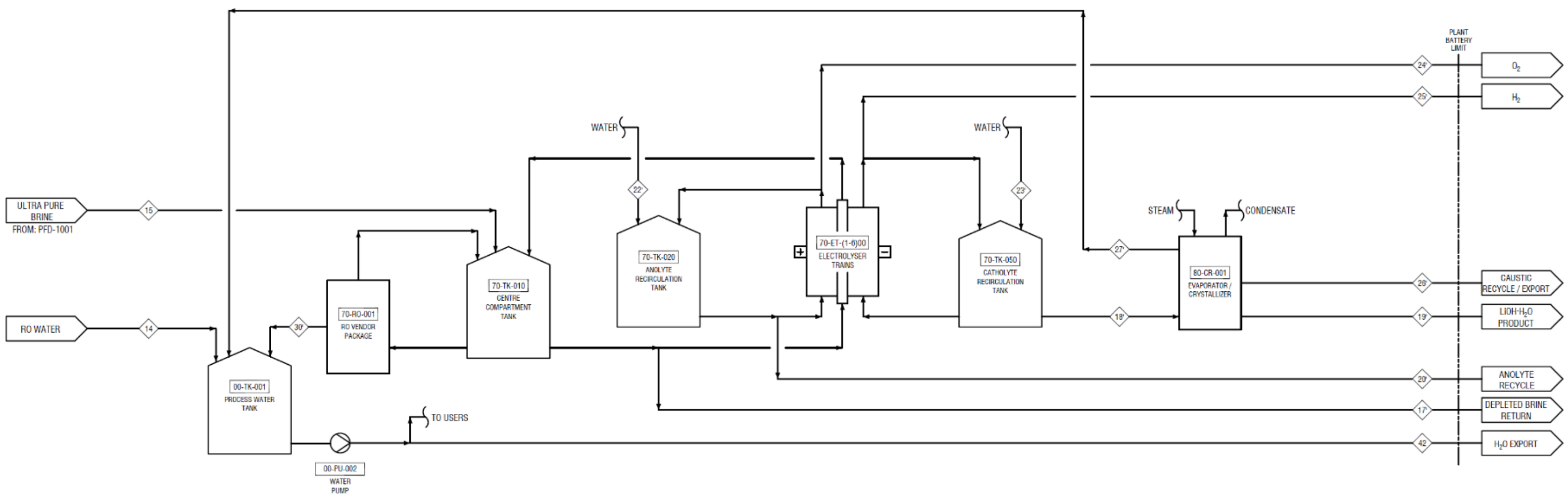

Figure 17-4. Preliminary block flow diagram of electrolysis and crystallisation process to produce Lithium Hydroxide Monohydrate (LHM) from the ultrapure lithium brine (PDF-1002)

17.3.3 Plant Layout

The conceptual layout in Figure 17-5 was developed based on the process design presented in this Report. This layout was used to estimate CAPEX for the plant included in Section 21. The overall plant footprint, as shown, is 185m x 140m.

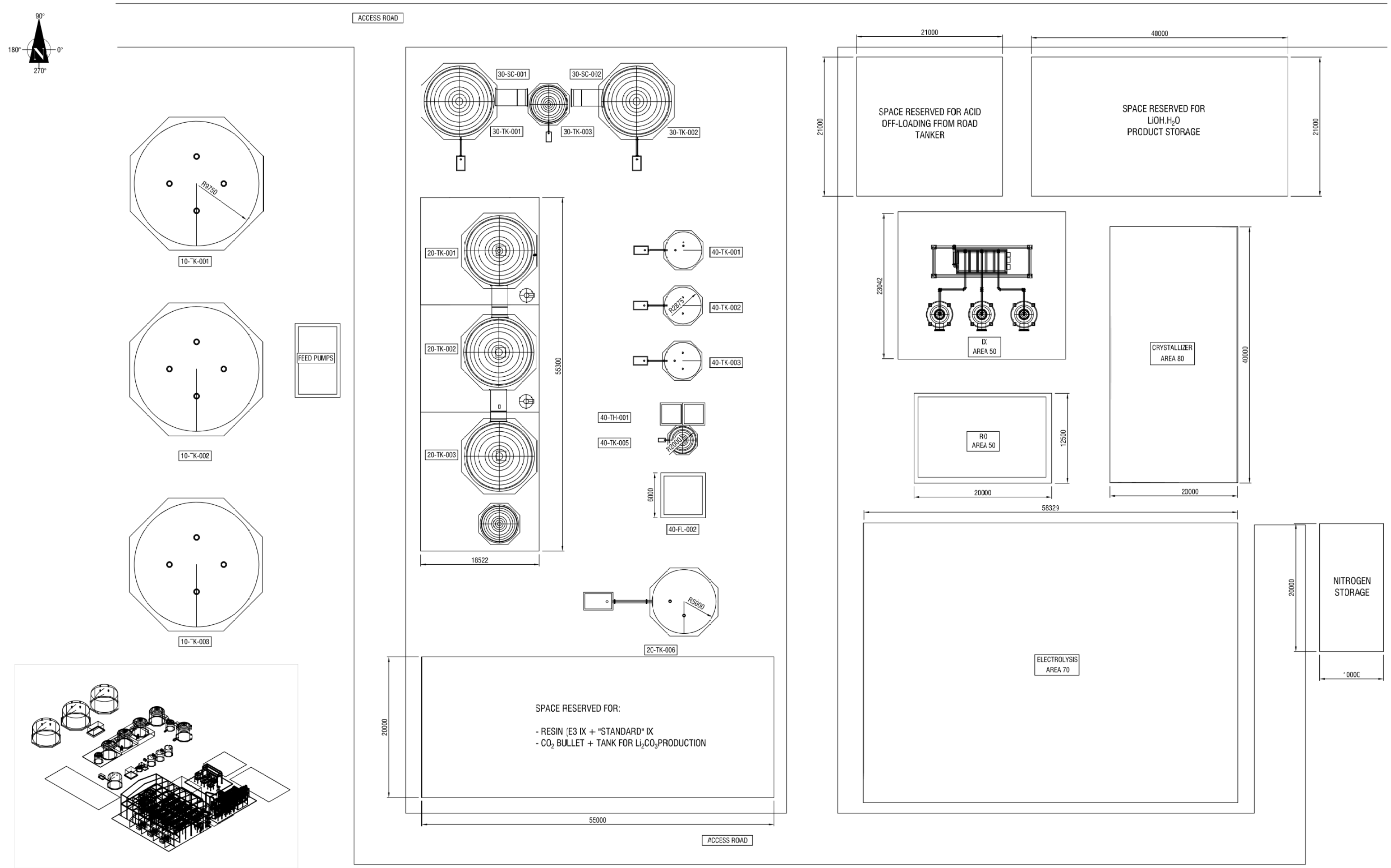

Figure 17-5. Overall lithium processing plant conceptual layout

18 Project Infrastructure

E3 Metals proposes to develop five (5) surface well pads for brine production. This includes two well pads in the north comprising of 21 wells, and two well pads in the south containing 21 wells. Brine from these well pads will be pumped from the well pads via individual wellhead Electric Submersible Pumps (ESP's). These ESP's will provide enough pressure to convey the brine from the well pads, through a fibreglass pipeline, to the Central Processing Facility (CPF). At the CPF the brine will undergo a pre-treatment process to remove H_2S from the brine prior to entering the lithium extraction process. Once through the lithium extraction process the lithium void brine will be comingled with the H_2S removed in the pre-treatment process and pumped through two pipelines to a nearby injection well pad. There are 21 injection wells at this pad.

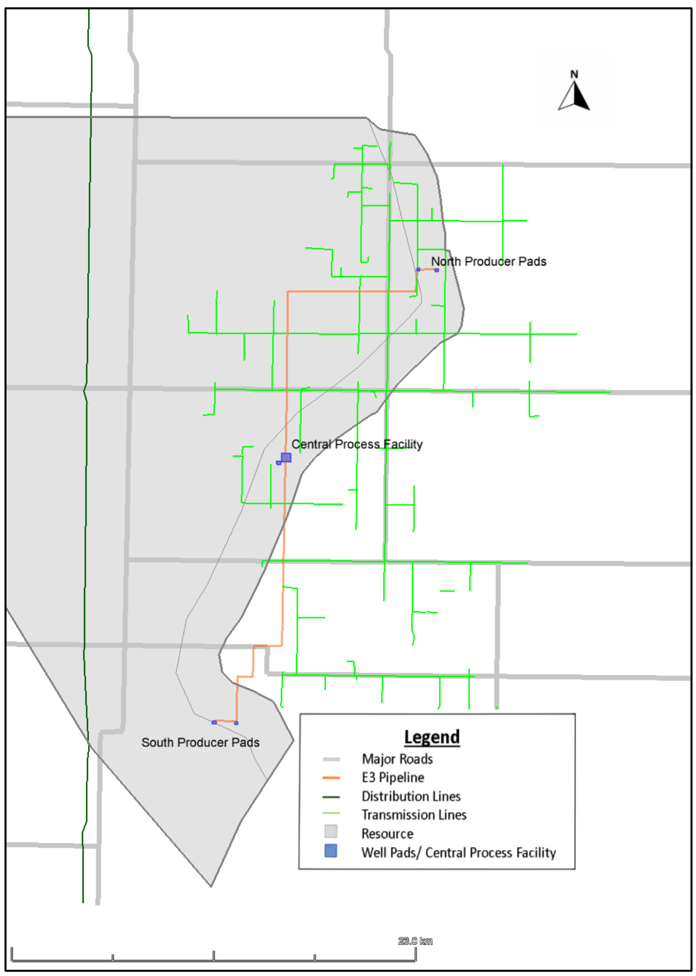

Figure 18-1. Map highlighting the proposed well network infrastructure in the CCRA

18.1 Brine Production Well Pads

Each well pad will consist of a row of production wells. The wells will each be equipped with a downhole ESP. Measurement equipment will be required to monitor production from each well. In addition, a chemical storage tank and pumps will be installed to inject hydrochloric acid (HCl) into the group production line. Acid injection will lower the pH of the water and assist with the H_2S removal process at the CPF.

The expected power consumption required for the two north production pads is 21 MW. The same power requirement is expected for the two south production pads. Power generation will be installed to provide the primary source of power to the pads. Included at each production pad is the capital equipment and costs to connect to the local service provider's distribution grid as a backup source.

Highway access is good for both the north and south production pads. Bulk hydrochloric acid tank trucks will have no issues accessing either site during summer or winter conditions. A short high grade gravel road will be required to connect the well pads to nearby secondary highways.

18.2 Brine Production / Natural Gas Pipelines

Each brine production well pad will be pipeline connected with a produced water and natural gas pipeline. These pipelines will convey brine from the wells as well as deliver natural gas from the CPF to each pad. The need for natural gas at the well pads is for power generation.

Approximately 70,000 m^3/d of brine will be produced from the north production pads, with the equivalent volume produced from the two south production pads. Due to the large volumetric flow requirements, an NPS 20" pipeline was selected to convey the brine. This pipeline material selected was fibreglass due to its high resistance to corrosion caused by saltwater.

Natural gas will be delivered to the well pads from the CPF through a NPS 4" steel pipeline. Approximately 149,000 Sm^3/d of natural gas will be required to provide fuel for the power generation equipment at each well pad.

The brine and natural gas pipelines will be installed in the same ditch. The direct distance from the CPF to the north and south production well pads is estimated at 15 km and 16 km, respectively. The pipeline routings take into consideration the surface infrastructure and therefore have a slightly longer distance of 19.3 km and 18.4 km to the north and south production well pads. Refer to Figure 18-1 for a map of the pipeline routing.

18.3 Central Processing Facility

Surface equipment at the CPF will consist of brine pre-treatment, lithium extraction, concentrate polishing, lithium hydroxide monohydrate production and brine re-injection equipment. The lithium processing equipment (lithium extraction, concentrate polishing, lithium hydroxide monohydrate production) is discussed in Section 17 and will not be addressed in this Section. Brine will enter the CPF at a design flowrate of 140,000 m^3/d and have an estimated H_2S concentration of 300 mg/L.

18.3.1 Brine Pre-Treatment

The brine pre-treatment process consists of two stages; gas stripping and H_2S polishing. The objective of these processes is to remove dissolved H_2S and ionic sulphides from the brine. The brine at the well pads may contain both dissolved H_2S and bisulphide ions. The split between these two species is pH dependent. By lowering the pH of the brine, the bisulphide ions convert into the dissolved H_2S form which can then be removed via gas-stripping. Reducing the brine pH is accomplished by adding HCl chemical at the well pads as discussed in Section 18.1.

The gas stripping process functions by contacting the brine with natural gas in a stripping tower where the dissolved H_2S and CO_2 gases will have an affinity to move into the gas phase from than the liquid phase. This occurs in a vertical tower with the brine flowing down through a series of trays inside the tower and the sweet gas flowing upward through the trays and being intimately mixed with the brine. The gas becomes progressively more sour as it travels upward while the H_2S content of the brine is reduced as it flows down through the tower. The brine leaving the bottom of the tower will have an H_2S concentration of 10 mg/L or less as it then proceeds to the polishing step.

Sour gas from the stripping towers needs to have the H_2S removed so that it can be recirculated back to the stripping towers. This will be accomplished by running the gas through an amine sweetening system. Prior to the amine system, the sour gas is compressed to a higher pressure in order to improve the efficiency of the amine system and allow the sweetened gas to free flow back to the stripping towers.

The amine sweetening system removes H_2S and CO_2 from the stripping gas by contacting the gas with diethanolamine (DEA) in the Amine Contactor Tower. Similar to the Gas Stripping Towers, the liquid DEA flows down through the tower where it comes into contact with the sour stripping gas rising up through the tower. The H_2S and CO_2 gases mix with the DEA solution and become chemically bound into the DEA as it leaves the bottom of the contactor tower (rich DEA). The rich DEA is then reduced in pressure and heated to reverse the reaction and liberate the H_2S and CO_2 from the rich DEA. This is accomplished through heat recovery from the lean DEA stream and by heat addition in the Regenerator Reboiler. This reboiler uses steam to indirectly heat the DEA. The liberated acid gases from the Regenerator Tower are then compressed and injected back into the brine stream where they will be re-dissolved into the liquid phase under pressure. The lean DEA solution is then recirculated back to the Contactor Tower to repeat the process.

The polishing step is designed to remove any remaining sulphides down to trace levels. This is accomplished by oxidizing the remaining sulphides into sulphate ions. Ozone is used as the oxidizing agent.

Ozone is created by compressing atmospheric air into a pressure swing absorption unit (PSA) where the oxygen gets separated from the nitrogen. The oxygen is then sent to an ozonation unit where it gets converted to ozone and injected into the brine. The sulphide-free brine is then transferred to the lithium recovery process. After recovery of the lithium the remaining brine is sent for reinjection into the aquifer.

The re-injection process consists of pumping lithium void brine from storage tanks (downstream of lithium extraction equipment) to the injection well pad that is located adjacent to the CPF.

Refer to the block flow diagram in Figure 18-2 for additional details on the process.

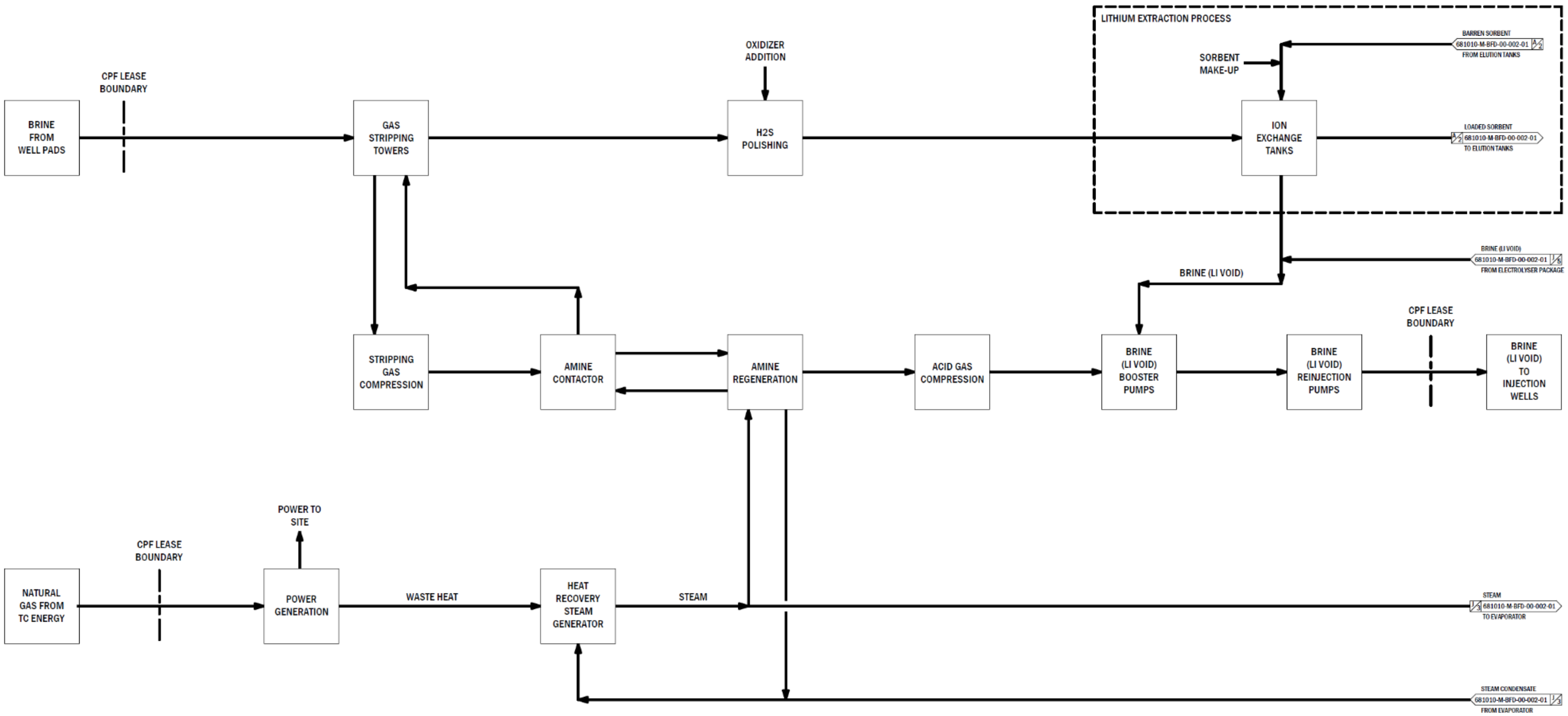

Figure 18-2. Brine Pre-Treatment Block Flow Diagram

The power consumption for the CPF is expected to vary due to the power draw from the brine re-injection pumps. As the injection well pressure builds over time additional power will be required for higher discharge pressures. Pressure on the wells is expected to vary from 2,000 kPag to 5,000 kPag gradually increasing over the first 10 years of the project then levelling out for the next 10 years. This brings the estimated power consumption from 50.5 MW in 2024 to 57.3 MW in 2034. The CPF will be connected to the local transmission grid. Power generation will be installed to provide a baseline power load and add redundancy to the CPF in case of line power outages.

There is close highway access to the CPF. Deliveries of reagents and exports of lithium will have no issues during summer or winter conditions. A short high-grade gravel road will be developed to connect the CPF to nearby secondary highways.

18.3.2 Injection Well Pad

The injection well pad will consist of two rows of injection wells. Each well will be equipped with a backpressure control valve and flow measurement device.

The expected power consumption required for the injection well pad is negligible. These power requirements can be met with connection to the local distribution grid. No backup power generation is required.

Due to the proximity of the injection well pad an access road can be shared with the CPF.

18.3.3 Injection Pipelines

The injection well pad will be connected to the CPF with two pipelines. Each pipeline will deliver lithium void brine from the adjacent CPF to the injection wells.

Approximately 140,000 m^3/d of brine will be sent from the CPF to the wells. This will be conveyed through two HDPE lined steel pipelines. The length of this pipeline is approximately 0.2 km from the CPF. Refer to Figure 18-1 for a map of the pipeline routing.

18.4 Natural Gas Supply

The CPF and well pads will require natural gas for power generation and for some process equipment. The total estimated quantity of gas required when power is being generated at the CPF and well pads is 785 e^3Sm^3/d. 1.2 km north of the CPF there is a gas transmission pipeline. This line contains dehydrated gas that could supply clean fuel to the power generation equipment.

A NPS 6” pipeline will connect the transmission line to the CPF. At the CPF lease edge a meter station will be installed. After metering the gas will be distributed to the CPF and also to the well pads via the NPS 4” natural gas pipelines.

18.5 Power Supply

The project has a requirement for power supply of approximately 99 megawatts (MW) overall to enable the brine production, circulation, conditioning and the extraction processes (as described above). The project is comprised of two main assets that require power: the CPF and the two production well pads. Two alternatives were analyzed, utility power and self- generation, as key sources for power supply based on initial value drivers such as reliability, availability, and cost competitiveness. Opportunities to source utility power from lower emission sources (wind) can be evaluated in the next stage of the project.

18.5.1 CPF Power Supply

The CPF requires approximately 57 MW of power with a high availability. Utility power and gas-fired turbine (self-generation) were analysed as the primary power sources for the CPF. This area of the province has an extensive power network that is able to supply large industrial loads. It also has a large supply of natural gas generated locally. Gas-fired power generation was selected for this study to maintain control of the power generation, to provide an opportunity to reduce emissions through potential sequestration and for the availability of lease-to-own options on the power infrastructure at competitive rate. Utility power has been considered as a backup source should the gas-fired generation unit go down. Through discussions with the local power distribution authority, it was determined that upgrades may be required to the local grid transmission system in order to connect and meet the requirements of E3’s CPF. These estimated upgrade costs are included in the capital cost to allow for connection to local Alberta grid power. In the operating cost, the monthly rate for distribution power was estimated based on similar energy facilities in the province, with the average of CAD 0.05 /kWh established for this Report.

18.5.2 Well Pad Power Supply

The north and south production well pads will require approximately 42 MW of power with a high availability. As with the CPF, both utility power and self-generation were analysed as primary power sources. Based on a cost analysis it was determined that power could be self-generated for a lower cost than utility power. The major cost savings for this option were the specific power generation equipment required and the low cost of natural gas. The estimated cost of the self-generated power at the well pads is CAD 0.043/kWh with utility back up costing CAD 0.05/kWh.

18.6 Power Generation

Based on the power supply analysis, the pre-FEED design includes self-generation of power at the two well pads. This includes on-site gas-fired turbomachinery, with a secondary utility power supply to ensure high availability requirements are fulfilled. Natural gas supply for these units would be provided by the pipelines installed in a common ditch with the brine production pipelines as described in Section 18.4.

As the primary power supply at the CPF will be utility power, a single gas fired power generation unit will be installed as a critical backup for the current study. Natural gas supply for this unit would be provided through a pipeline connected to the transmission line as detailed in Section 18.4.

A lease to own agreement can be negotiated for the supply and installation of the power generation equipment. This foregoes the capital investment in favor of a financed cost over the lifespan of the project. Operating capital for this equipment includes the cost of gas at CAD 4.09/GJ (Enmax 5-year gas price average) and the expected maintenance and overhaul costs. These costs are blended in the electrical costs detailed in Section 18.5.

Cogeneration was evaluated for use of the waste heat from the power generation units. Further studies need to be completed to determine the viability of this option given the large capital and ongoing maintenance costs.

18.7 Highway Infrastructure

Highway infrastructure in this area of the province is very well developed. High load corridors are nearby, there are a number of paved secondary highways and some township roads are paved. This will make transporting large equipment to site feasible with minimal third-party line lifts required. Delivery of chemical, reagents and export of lithium will be easily accommodated.

18.8 Fuel, Chemical and Reagents

Diesel and gasoline required for operations trucks and heavy equipment can be obtained from the towns of Trochu or Three Hills. Both towns are approximately 25 km's from the CPF.

Chemical and reagents will be shipped in totes or bulk from Red Deer to the CPF or well pads. On-site storage will meet all regulatory storage requirements and, depending on toxicity will be stored in designated areas with restricted access.

19 Market Studies and Contracts

19.1 Lithium Demand

The demand for lithium continues to grow with the need for effective energy storage. The largest demand for lithium is the rechargeable battery market and is growing rapidly. Rechargeable lithium-ion batteries are used in portable electronic devices, electric vehicles and high performing storage cells for intermittent renewable energy sources. Electric vehicles are going to be the largest growth section that will consume lithium-ion batteries, and therefore accounts for a large portion of demand growth for lithium. Figure 19-1 shows the number of electric vehicles is projected to rise to nearly 10 million as soon as 2025 and by 2035, more than 50% of all new car sales will be electric (Rho Motion, 2020).

Lithium-ion batteries are the preferred choice for electric vehicles due to their lightweight and high energy density. Lithium-nickel-manganese-cobalt (NMC), lithium-nickel-cobalt-aluminum (NCA), lithium manganese-oxide (LMO), and lithium-iron-phosphate (LFP) batteries are all options to energize the electric powertrain and require a material content of approximately 7% lithium (Seddon, 2018). These batteries require different lithium compounds depending on the specific cathode chemistry. Most commonly, these include lithium hydroxide and lithium carbonate, with hydroxide required increasingly over carbonate into 2030 (Figure 19-1).

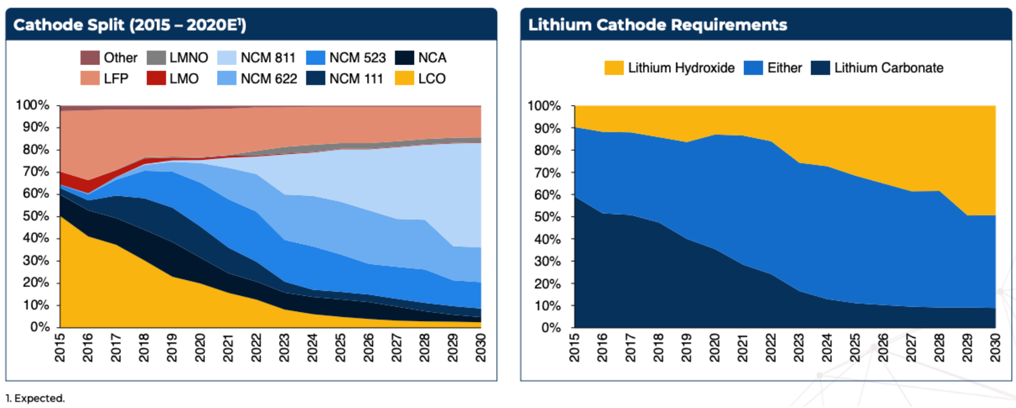

Figure 19-1. Forecasted cathode chemistries and related lithium compound requirements as a percentage of the market to 2030 (Benchmark Mineral Intelligence, 2020)

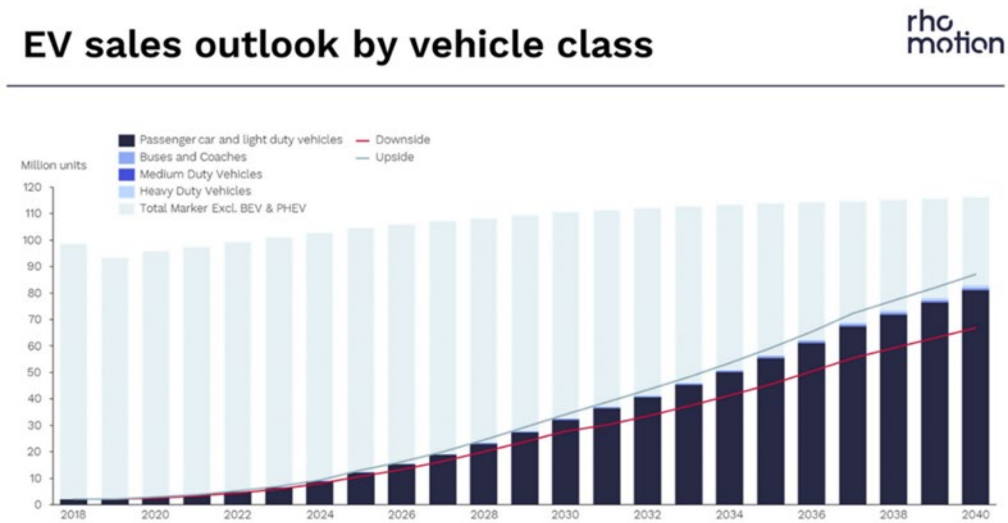

Figure 19-2. Global Car Sales by EV and ICE 2018-2040. Light blue: Total vehicle market. Dark blue: Battery (BEV) and Plugin Hybrid (PHEV) electric vehicle market. (Rho Motion, 2020)

Lithium demand is being bolstered by drop in price of the battery electric vehicle (BEV) relative to the internal combustion engine (ICE) vehicle over the coming years (Figure 19-3). This is in part the cost of the lithium-ion battery and the increase in energy density relative to that. It is also due to the efficiencies in the production lines as more vehicles are sold on a pure EV platform. The price parody between the two vehicle types is predicted to occur in 2024 and corresponds with a significant anticipated increase in the demand for lithium as BEV car sales ramp up.

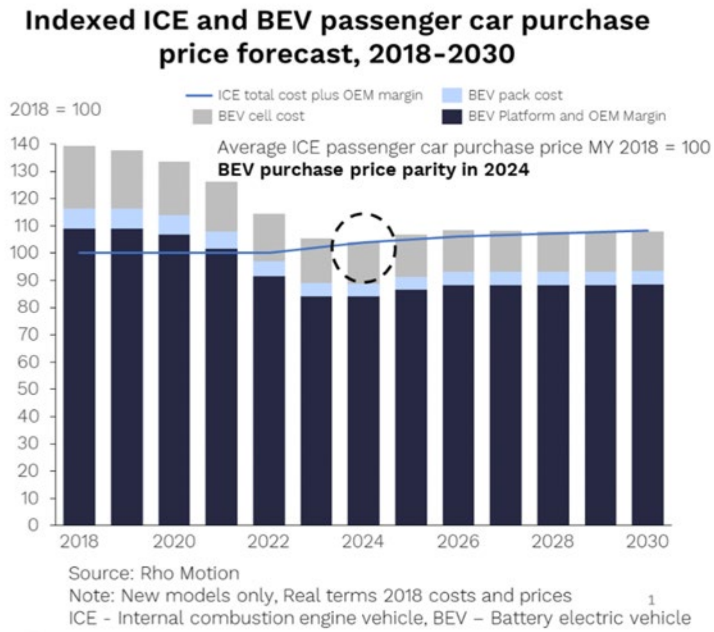

Figure 19-3. Indexed Internal Combustion Engine and Battery Electric Vehicle car price forecast to 2030 (Rho Motion, 2020)

19.2 Lithium Supply

Market performance in the last few years would suggest the lithium supply curve may be tempered by the challenges current producers are facing to bring lithium compounds to market. These challenges range from shipment times, to testing and qualification of battery-grade lithium hydroxide. As lithium hydroxide is a specialty chemical and not a straight commodity mineral, the steps to refine from a raw material to battery grade lithium is more complex and nuanced.

E3 expects demand to overtake supply in 2025 through 2027 due primarily to aggressive commitments from automakers to bring new electrical vehicles to market. Bloomberg New Energy Finance predicts that global production of lithium will be at least 1,000,000 metric tonnes by 2025, and up to 2,000,000 metric tonnes by 2030 (BNEF, 2019) with approximately 80% of the demand being driven by lithium-ion batteries.

The timing of the forecasted increase in demand is well aligned to E3's planned entry into the lithium market in 2024. As both cathode and vehicle manufacturers look to secure a reliable and stable source of lithium, we believe we will be well positioned to secure approximately 2-5% of the growing lithium hydroxide market by 2025.

19.3 Lithium Hydroxide Price

A detailed future pricing study for lithium chemicals was not completed for this PEA. The average price used for future sales of battery-quality lithium monohydrate hydroxide was developed by reviewing pricing data generated from reliable sources as reported in publicly disclosed data collected from peer companies.

The future average selling price of CAD 19,007/tonne lithium hydroxide monohydrate (LHM, USD 14,079/tonne LHM) is consistent with that used for publicly released economic assessments of other lithium projects in the previous 4 months. Future selling prices of -30%/+30% were modelled as part of a sensitivity analysis exercise included in Section 22 Economic Analysis of this Report.

20 Environmental Studies, Permitting and Social or Community Impact

20.1 Environmental Considerations

Wells in Alberta have an impact on the surface of the land in the form of disturbance for transportation, lease construction, pipelines, and wellheads. Certain protected areas require environmental assessments prior to construction for drilling a well or construction of the industrial site. Similarly, some areas fall under wildlife protection and also require studies to ensure minimal disruption to species at risk. Such areas often have more stringent guidelines as to the drilling of wells and may require additional surveys and may have restrictions as to the placement of wells and/or the timing in which wells may be drilled. The CCRA falls outside of Caribou and Grizzly protection areas. There are several environmental benefits to E3's Clearwater Lithium Project, described in the following sections.

20.1.1 Net Positive Fresh Water Production

Traditional lithium projects are large net-consumers of fresh water. Through the process outlined in Section 17, E3 anticipates it will produce approximately 8.3 m^3/hour net fresh water through the Reverse Osmosis (RO) stage for water removal for the electrolysis package. This water can be made available to the local population for agriculture, livestock or human consumption purposes.

20.1.2 Low Land Disturbance and Repurposing Potential

The estimated land footprint of the wells pads and process facility is approximately 98 hectares. The is a very small portion of land (<10%) compared to that used by typical mining or evaporation projects that produce similar quantities of lithium products.

In addition, E3's project is located in an area that has been well developed for oil and gas production. This provides many potential surface location sites with known geology and access to amenities like roads that could be repurposed for multi-well pads or the central processing facility. Repurposing existing sites would even further reduce E3's expected land disturbance, preserving the energy and investment in sites that are currently a liability to operators and the province.

20.1.3 Potential for Net-Zero GHG Lithium

The majority of the energy consumed on this project is electricity. The major consumers include the pumping of the brines to the surface and the production of 99.9% pure lithium hydroxide. This Report contemplates using natural gas cogeneration with a grid-connected backup power source at all sites. At this stage of the project there are several alternatives to the base case outlined in this Report including nearby renewable generation. Other behind-the-meter configurations are under review with an eye on their carbon content and their ability to deliver high resilience power.

E3 Metals recognizes the importance of sustainability to our future customers and stakeholders. Therefore, E3 plans on reducing the carbon footprint of the project to produce net-zero carbon emissions. While not contemplated in this level of Report, the power delivery solutions outlined in this Report are flexible at the current project stage and could accommodate the implementation of carbon reduction into the project life as the project moves forward.

Alberta has a robust renewable energy sector and there is an existing 80 MW wind farm located near the project site, as well as other projects planned in the area. Some existing renewable energy facilities have power storage capabilities to address the intermittent nature of renewables. This provides for an opportunity to secure "firm" power delivered directly to the well pads, north and south of the CPF.

Common in Western Canada, Carbon Capture and Storage technology is readily available and could potentially be tied to power generation in the project. The technology strips the CO2 from the exhaust gas of gas fired power plant and it is then it could potentially be sequestered into the brine waste stream to reside permanently in the aquifer.

20.2 Permitting

20.2.1 Alberta Energy Regulator

Similar to brine wells for producing salt, it is expected that permitting for lithium brine production and injection will be handled by the AER. In Alberta, the regulation and permitting of water wells is determined by the salinity of the water being produced from the aquifer. Wells drilled for the purpose of producing water with salinity greater than 4,000 mg/L fall outside the Water Act. These wells follow standard oil and gas regulations through the Alberta Energy Regulator (AER). Because the Leduc brine salinity typically averages over 200,000 mg/L, the company's permitting process is anticipated to fall within the standard oil and gas AER regulations.

The permitting process for brine production and injection wells with salinity greater than 4,000 mg/L, such as those designed to produce from the Leduc aquifer in E3 Metals' permit area, is well defined. The process will involve obtaining a license with the Alberta Energy Regulator for a Water Source Well and a Water Injection Well under AER Directive 56[13]: Energy Development Applications and Schedules. The company will be required to consult with various stakeholders and gain authorization from mineral rights

[13] https://static.aer.ca/prd/2020-07/directive-056_0.pdf

owners, including First Nations, trappers and surface landowners under a Participant Involvement Program, and obtain an AER business associate (BA) code from the Petroleum Registry of Alberta.

A Lahee classification is a "pre-spud" (pre-drilling) assignment given to each well based on the geological complexities relating to oil and gas exploration. The Lahee classification applicable to wells drilled for brine production and water disposal is "OTH" and may be licensed under Regulation Section 2.020 or 2.040 of the Oil and Gas Conservation Regulations (OGCR). This regulation section is indicated in the Well License Application. The Well License Application can be found in Schedule 4 of Directive 56.

Because the brine water produced will likely contain various amounts of dissolved H_2S, schedule 4.3 of Directive 56 will be required for the license application. An emergency planning zone (EPZ) will need to be identified and a mitigation strategy outlined to ensure safe operations. A setback from permanent dwellings, public facilities, etc. will be required based upon the wells H_2S release rate, similar to that applied to the existing oil and gas development in the area. Dissolved gas concentrations are to be further tested in the CCRA to confirm regulatory and operational requirements.

Injection and disposal requirements will also be met as per AER Directive 51[14]: Injection and Disposal Wells. The directive outlines the cementing requirements, testing to ensure zone isolation and monitoring parameters. The injection wells will be categorized as Class II for injection of produced water (brine) or brine equivalent fluids.

Applications for Compulsory Pooling and Special Well Spacing should be made through Directive 65[15]: Resources Applications for Oil and Gas Aquifers. Preparation for these applications will involve the submission of advanced geological mapping and well network definition. As part of this process, E3 also plans to conduct proactive notification and consultation with other operators in the area, most of whom E3 is already acquainted with through our sampling program and other activities.

An Alberta Electricity Systems Operator (AESO) approval will be required if E3 Metals' project connects to transmission, as outlined in this Report. For connection to distribution, E3 Metals will require an approval from Alberta Energy and Parks (AEP) and/or local landowners. E3 Metals is currently working towards an electricity solution that supports net-zero greenhouse (GHG) emissions in the production of lithium hydroxide. Once this net-zero GHG solution is finalized, E3 Metals plans to develop and initiate a comprehensive regulatory approval plan to for the selected net-zero GHG energy pathway(s).

According to the Government of Alberta, Proponent-led Indigenous Consultations are managed through the Aboriginal Consultation Office (ACO), who direct, monitor and support the consultation activities of

[14] https://www.aer.ca/documents/directives/Directive051.pdf
[15] https://static.aer.ca/prd/documents/directives/Directive065.pdf

Government of Alberta departments. As such, the ACO coordinates with the Alberta Energy Regulator (AER) and Alberta Environment and Parks (AEP). E3 Metals plans to work with key stakeholders to ensure appropriate consultation is completed with local Indigenous communities.

20.2.2 Environmental Protection and Enhancement Act (EPEA)

The Environmental Protection and Enhancement Act contains a list of designated activities that require EPEA Approvals, Registration or Notice. EPEA Approvals are required for all oil sands minds, surface quarries and certain facilities that carry risk of contamination of the environment. EPEA approval documents:

- Place limits on air emissions, pollution, sizes of surface ponds and infrastructure;
- Outline conservation & reclamation requirements; and
- Provide a framework for reporting and monitoring obligations

Lithium production is not on the list of EPEA "designated activities" so E3 anticipates that an EPEA approval will not be required. All environmental mitigations and reporting requirements are expected to be captured within the various applicable AER directives.

E3's project may require an Environmental Impact Assessment (EIA). In the Environmental Activities Mandatory and Exempt Activities Legislation[16], Lithium production is classified as "Discretionary", meaning that the requirement for an EIA is determined by the Director.

20.3 Social or Community Impact

Oil and gas development has occurred in the resource areas over the last 70 years, primarily for Nisku and Leduc targets, in addition to some Cretaceous, Mississippian and deeper Devonian targets. This has resulted in the evolution of many communities who sustain themselves economically on a foundation of oil and gas activity. Many of the oil and gas fields in the resource area, while still producing, are well beyond peak production and produce only at marginal rates. Most of the oil and gas wells targeting the Leduc in the area have been shut in, and it is uncertain whether they will produce again.

One of the unique aspects of lithium development in Alberta is that it will operate in a very similar fashion to oil and gas given the required techniques to produce and move brine (wells, pumps, small pipelines) are the same. E3's DLE process has been designed to link oilfield and lithium processing together seamlessly. The Company's strategic location in the heart of Alberta's oil and gas development is a major advantage with known geology and available infrastructure. This allows E3 to tap into Alberta's expansive workforce and subcontractors to develop and operate our project.

[16] https://www.qp.alberta.ca/documents/Regs/1993_111.pdf

E3 can direct hire the majority of its work force locally for both staff and construction contractors with oil and gas expertise. With the advanced development of Alberta's lithium resources, Alberta can leverage core competencies in resource extraction while diversifying the energy sector towards a parallel and emerging commodity opportunity that supports a low carbon future. In addition to head offices in Calgary, E3 plans to hire from nearby municipalities, Indigenous communities and education institutions in our project area to deliver both social benefits in addition to economic benefits.

The development of a local lithium industry also creates the opportunity to attract a broader ecosystem, such as manufacturing of lithium products like battery components, to Alberta – a potential new hub of lithium activity. Canada is already ranked 4th in the world for lithium-ion battery supply chain according to Bloomberg[17]. Part of this ranking includes Canada's abundant natural resources, in particular critical minerals like lithium, nickel and graphene and Canada's track record of sustainable development. Recently both Ford and Fiat Chrysler announced plans to begin manufacturing electric vehicle in Ontario, Canada. Development along the entire length of the value chain could provide a catalyst for further energy storage development and manufacturing in Canada, providing additional Gross Domestic Product (GDP), technology, and employment while stimulating local economies.

Lithium production – and in particular net zero GHG lithium – will also support Alberta and Canada to meet its emissions reduction goals. Electric vehicles, powered by lithium-ion batteries, avoid greenhouse gas emissions in comparison to internal combustion engines. Lithium is also used in industry-grade battery storage and could support an economic, non-fossil fuel related source of electricity stability for intermittent renewable energy sources. As it is anticipated that most of the development of renewable energy sources over the next decade will be in the form of wind or solar power. Energy storage, supported by large scale Li-ion batteries, could be a vital component of grid stability and energy security.

21 Capital and Operating Costs

The basis of the estimate for the PEA of the Clearwater Lithium project is a breakdown of the project's individual components where costs have been estimated. The estimate evaluates the economic viability of the project to justify additional efforts to further develop the project in areas such as geological testing, geographic assessments, analysis of existing and needed infrastructure and further detailed engineering. Costs were estimated using a factored installation estimates based on major equipment pricing. These installation factors were based on previous oil and gas projects completed in Alberta from 2012 to 2020 of similar scope.

Further information was given to the authors of the Clearwater PEA which enhanced the confidence and detail of the design basis and cost estimates. These areas include historic aquifer production data, metallurgical test work, previously conducted evaluation studies and project reports. GLJ provided their

[17] https://www.mining.com/new-ranking-has-canada-4th-us-6th-in-lithium-ion-battery-supply-chain/

cost estimate for the drilling, completions, and downhole pumps, while SCOVAN conducted an installed factored estimate for the remaining processes with contributions on lithium extraction equipment from NORAM.

21.1 Capital Basis of Estimate

21.1.1 Brine Production/Injection

The capital cost estimation for the wells required for brine fluid production and injection was completed by GLJ. The drilling cost estimates are based on drilling performance analysis on close proximity wells, in addition to an analysis of data from Xi Technologies Offset Analyzer, a database which provides the total costs of the majority of wells drilled in Alberta. The drilling costs were based upon a similar intermediate casing size with a total drilled depth of 2,600 m True Vertical Depth (TVD) with an average drill rate 117 m/day (including the time required to cement casing). A drilling cost of CAD 2,960,000 per well was therefore estimated for production wells, which includes drilling time, completions and the production pump. Contingency was added in the form of additional drilling time as most the total costs are time-based. A cost-based contingency was also added to the completions estimate. This estimate also benefitted from a comparative analysis with geothermal wells which have similar design and operating parameters.

Cost estimates for the pumps and surface equipment are based on the Baker Hughes Centrilift high flow rate pump, with a cost of CAD 690,000 per pump including all accessories. The pump costs are believed to be conservative given efficiencies in the design that can be completed and the purchasing power of buying multiple pumps.

Costs associated with the surface equipment required at the well pads were estimated based on similar oilfield related source water well tie-ins. This includes metering, injection pumps, storage tanks, as well as some associated piping to connect the production with the pipeline riser. An installation factor of 2.5 was applied to cover the direct and indirect costs associated with the mechanical, civil, electrical and instrumentation installation costs as well as engineering. Contingency was applied separately as discussed in Section 21.1.7.

Costs associated with the brine booster and injection pumps required at the central processing facility were based on budgetary quotes received from equipment suppliers. An installation factor of 4 was applied to account for direct and indirect cost of the on-site building and assembly requirements, mechanical, civil, electrical and instrumentation construction costs as well as engineering. Contingency was applied separately as discussed in Section 21.1.7.

Pipeline costs were estimated based on material prices received from suppliers along with installation and land costs from previous projects. Pricing received from suppliers includes the cost for the NPS 20” fiberglass brine production line pipe and NPS 4” natural gas line pipe, Survey, Land and Environmental costs were estimated based $/m typical for this area of the province for oil and gas projects. Installation and contract services were also based on a $/m cost for a common ditch pipeline of this size. Indirect costs such as engineering, and inspection were based on estimated amounts from similar sized projects. Contingency was applied separately as discussed in Section 21.1.7.

21.1.2 Pre-Treatment

Direct costs associated with the equipment required for the processing of the brine upstream of the lithium extraction process were based on information received from suppliers and rule of thumb estimates. The gas stripping towers, amine plant, ozone and oxygen generation equipment pricing was received from suppliers. Boiler pricing was based on recent quotes for another project of similar size and scope. Compression costs were estimated using a $/bhp formula applicable to gas projects. An installation factor ranging from 2.5 to 3 was applied to account for direct and indirect cost of the mechanical, civil, electrical and instrumentation construction costs as well as engineering. Contingency was applied separately as discussed in Section 21.1.7.

The pipeline and meter station costs associated with the tie-in to the gas transmission pipeline were based on previous meter station installations of similar scope. NPS 6" line pipe pricing was obtained from pipe vendors. Survey, Land and Environmental costs were estimated based $/m typical for this area of the province for oil and gas projects. Installation and contract services were also based on a $/m cost for a single ditch pipeline of this size. Indirect costs such as engineering, and inspection were based on estimated amounts from similar sized projects. Contingency was applied separately as discussed in Section 21.1.7.

21.1.3 Lithium Processing

The direct costs for the capital cost estimate for the Lithium Processing Facility are based on the preliminary process flow diagrams and equipment list compiled for the project and discussed in Section 17. An order of magnitude estimate for the equipment supply was developed by NORAM excluding all fees, contingency and engineering related costs, sourced from:

- Budget pricing from vendors
- Pricing based on recent projects
- Estimates and factors
- Online databases

These equipment costs were incorporated into the overall capital cost estimate by SCOVAN, including balance of plant costs and installation and reviewed jointly by all parties. Equipment installation factors from 1.3 (tank installation) to 2.5 (pump installation) were used to estimate mechanical, civil, electrical and instrumentation construction costs.

The indirect costs including engineering (8%), construction management (3%), commissioning (3%), construction equipment (80%) and freight (6%) were estimated based on percentages of the total installation cost and expected construction labour costs.

21.1.4 General Site Costs

General site costs consist of direct costs such as land acquisition, reagent and chemical first fills, and grading/lease preparation for the central processing facility and well pads. Land acquisition costs were estimated based on similar size projects completed in Alberta. Grading costs were based on $/m^2 metrics derived from multiple previous projects. All reagent and chemical costs were based on estimated equipment fill volumes, and current unit pricing provided by suppliers.

21.1.5 Power Generation and Transmission

Power generation and line power costs were estimated based on preliminary information provided by the electrical service provider and power generation suppliers. Given the significant power requirements of the facilities a number of power generation units are required. For line power, connection to the local distribution network was sufficient for the well pads. However, the demands of the central processing facility will require upgrades to the transmission network.

No capital costs were associated with power generation as it was assumed that this would be financed as a blended power unit cost of CAD 0.05/kwh. Line power included a capital component of CAD 30.25 M which includes the tie-in to the distribution system and transmission system upgrades. This capital cost assumes that a majority of the initial build cost would be worked into the electrical price as is typical with long term service agreements in Alberta.

A summary of all the significant power loads is detailed in the table below.

Table 21-1. Estimated power consumption

Equipment	Estimated Power Consumption in 2024 (MW)	Estimated Power Consumption in 2044 (MW)
Brine Production/Injection	49.1	56.2
Brine Pre-Treatment	17.4	17.4
DLE Process (Li-IX)	1.7	1.7
Lithium Production	20.3	20.3
Site Costs	0.26	0.26
Total Power Requirements	**88.8**	**95.9**

21.1.6 Sustaining Capital

Sustaining capital requirements encompasses the replacement of major equipment that are not serviceable with normal maintenance. For this project this includes the downhole ESP's on the brine production wells. It is expected that these pumps will need to be replaced at an interval of 2.75 years.

Rotating surface equipment is expected to survive the full project lifecycle through regular maintenance and overhauls. These costs have been included in the operating expenditures section.

Membrane, anode and cathode replacement have been included as operating costs in Section 21.2.3.

21.1.7 Contingency

A contingency of 25% was applied to the direct costs associated with the surface equipment at the well pads (production and injection) and central processing facility. Contingency on Drilling and Completions operations and equipment was estimated at 20%. The level of contingency applied to each area reflects the confidence in the design at this stage of development.

21.1.8 Capital Expenditures Summary

A summary of the project capital costs are provided below.

Table 21-2. Capital Costs

Capital Costs	Description	Costs (M CAD)	Costs (M USD)
Brine Production/Injection	Wells, pumps and pipelines	\$260.3	\$192.8
Brine Pre-Treatment	H_2S Removal	\$159.0	\$117.8
DLE Process (Li-IX)	Primary extraction of lithium from the brine	\$21.1	\$15.6
Lithium Production	Concentration, Polishing, Electrolysis and Crystallization	\$217.2	\$160.9
Power, Site, Transport and Labour Costs	Misc. Site and labour costs	\$47.4	\$35.1
Contingency (25%)	Applied to direct capital costs	\$107.7	\$79.8
Total		**\$812.7**	**\$602.0**
Sustaining Capital	Pump replacement, etc.	\$146.7	\$108.7

The total initial capital cost of the Project for 20,000 tonnes per year production of LHM is estimated at CAD 812.7 Million, inclusive of direct and indirect costs and contingency. In additional, CAD 146.7 Million of sustaining capital is also estimated, with the majority of this cost associated with the replacement of brine production pumps.

21.2 Operating Basis of Estimate

21.2.1 Reagents / Chemicals

Reagent and chemical costs represent a large portion of the operating capital required for the facilities. Quantities for each component were estimated based on process requirements. The cost for the reagents and chemicals were verified with chemical suppliers located in Red Deer, Alberta. It should be noted that some of these chemicals are required in large quantities (e.g., Hydrochloric Acid) so bulk pricing and delivery costs were obtained. This would include tank trucks full of chemical or reagent delivering to a storage tank on-site. Other substances were needed in smaller volumes (e.g., Anti-Scalent) so it was assumed these were delivered in totes on a picker truck. All costs used in the estimate included transportation to site. The costs associated with these reagents/chemicals are summarized in the table below.

Table 21-3. Reagent and consumables costs

Reagent	Qty/tonne LHM	Unit Cost (CAD)	CAD/tonne LHM
Corrosion Inhibitor	0.02 m^3	$3,500/$m^3$	$75
Hydrochloric Acid (31.5% wt)	4.03 m^3	$240/$m^3$	$967
Sodium Hydroxide (50% wt)	0.91 kg	$0.70/kg	$0.6
Diethanolamine	0.0037 m^3	$1,568/$m^3$	$5.8
Anti-Scalent, SD-9009	0.00007 m^3	$10,725/$m^3$	$0.8
E3 Sorbent	52.82 kg	$9.48/kg	$501
Sulphuric Acid (93% wt)	0.011 m^3	$202.4/$m^3$	$2.2
Nitrogen	12.08 Nm^3	$0.54/$Nm^3$	$6.5
Carbon Dioxide	483.2 kg	$0.13/kg	$62.8
Cellulose Filter Aid	20.13 kg	$1.00/kg	$20.1
Total			**$1,641.8**

21.2.2 Power Requirements

Power generation and line power costs were estimated based on preliminary information provided by the electrical service provider and power generation suppliers.

Discussions are ongoing with the local electrical service provider, however a rate of CAD 0.05/kWh as a blended power unit for lease to own gas-fired power generation facility. This was established based on pricing provided to other oil and gas producers in Alberta. This rate was applied to the power costs at the central processing facility.

Power generation costs were based on the cost of fuel (natural gas) of CAD 4.09/GJ (Enmax 5-year gas price average) and the lifecycle maintenance costs for the equipment. The power generation cost of CAD 0.04/kWh was used for the well pad electrical estimate, which is less for the well pad generation due to optimized and smaller generation equipment.

Table 21-4. Power costs

Process Area	Consumption (kW)*	Consumption (kWh/tonne LHM)	Unit Cost (CAD/kWh)	CAD/tonne LHM
Brine Production/Injection	54,200	21,824	$0.050	$1,091
Brine Pre-Treatment	17,400	7,006	$0.043	$301
Lithium Processing	22,040	8,875	$0.043	$382
Site Costs	262	105	$0.043	$4.5
Total				**$1,778.5**

*Average power over 20 years

21.2.3 Maintenance and Servicing

Maintenance for downhole well servicing and workovers have been provided by GLJ to be CAD 2.36M per year. This includes scale removal, rod repair and other non-pump replacement items.

Table 21-5. Maintenance and servicing for downhole ESPs and completions

Equipment	CAD/tonne LHM
Well Servicing	$118
Total	**$118**

Ongoing maintenance costs associated surface equipment are summarized in the table below. It also excludes maintenance required for the power generation equipment as this is included in the electrical supply costs.

Table 21-6. Maintenance and servicing costs for injection and pre-treatment

Equipment	Overhaul Interval	Overhaul Cost (CAD)	Yearly Consumable Costs (CAD)	CAD/tonne LHM
Brine Injection Pumps	5 years	$529,000/year	N/A	$2.6
Gas Stripping Compressors	5 years	$968,000/year	$80,000/year	$11.3
Acid Gas Injection Compressors	5 years	$80,000/year	$5,000/year	$0.9
Total				**$14.8**

A 4% factor was used to estimate the maintenance and servicing costs for the lithium processing equipment. This has been further shown as a labour and equipment portion as is applied to the direct field costs. Additional line items for large maintenance equipment were added on top of the 4% factor. These capture membranes, anodes and cathode replacements within the lithium process steps.

Table 21-7. Maintenance and servicing costs for lithium process

Equipment	Annual Servicing Cost (CAD)	CAD/tonne LHM
E3 Ion Exchange	$826,000	$41.3
Polishing	$1,515,000	$75.7
Electrolysis and Crystallization	$,630,000	$481
Site Costs	$369,000	$18.5
Surface Costs (Wellpad and road maintenance)	$2,782,000	$139
Total		**$755.5**

21.2.4 Solids Disposal

Disposal of a small quantity of solid filter cake produced through the lithium concentrate polishing step the required. The filter cake will be composed of carbonate and hydroxide compounds precipitated from the concentrate and can be disposed of at a landfill under general waste.

Table 21-8. Solids Disposal

Process Area	Produced Rate	Landfill Fee (CAD)	CAD/tonne LHM
Lithium Processing	0.7 m^3/hr	$132/$m^3$	$37.2
Total			**$37.2**

21.2.5 Water

After the initial fill the central processing facility is expected to be a net positive generator of potable water. This water can be used for make-up in the steam generation system and/or be provided to landowners for irrigation.

21.2.6 Natural Gas

Natural gas will be required for power generation at the production well pads as well as fuel gas for the boiler at the central processing facility. The estimated volumetric requirements are 315 e^3Sm^3/d. The cost of the gas has been estimated at CAD 4.09/GJ (Enmax 5-year gas price average).

Table 21-9. Natural gas costs

Equipment	Consumption/year	Qty/tonne LHM	Unit Cost (CAD)	CAD/tonne LHM
CPF Boilers	258,283 GJ	12.9 GJ	$4.09/GJ	$52.8
Total				**$52.8**

21.2.7 Personnel

Personnel costs and shift cycles are based on similar sized oil and gas facilities in Alberta. Office shifts are estimated based on an 8-hour single shift per day, and 5-day work week. Field shifts are estimated based on three 8 hour shifts per day, and 7-day work weeks. The central processing facility will be manned 24 hours a day whereas the production and injection well pads will only need to be visited on an intermittent basis. The close proximity of major cities to the central processing facility will eliminate the requirement for camp facilities.

Table 21-10. Staffing costs

Staff	Full Time Employees (FTE)	Total Yearly Cost to Company (CAD)	CAD/tonne LHM
Office			
Human Resources	1	$150,000/year	$7.5
Administration	2	$150,000/year	$7.5
Accounting	1	$200,000/year	$10
Engineering	3	$500,000/year	$25
Marketing	2	$150,000/year	$7.5
Geologists	2	$250,000/year	$12.5
Site Management			
Foreman	2	$591,300/year	$29.5
Site Share Services			
Laboratory	2	$350,000/year	$17.5
Maintenance	4	$800,000/year	$40
Operators by Area			
Brine Production	2	$350,000/year	$17.5
Pre-Treatment	15	$2,250,000/year	$112
Processing Plant	6	$985,500/year	$49
Total		**$6,726,800/year**	**$335.5**

21.2.8 Product Transport

All reagent pricing includes transportation to site, therefore the only cost under this section refers to the shipment of the produced LHM. It is assumed to be transported via rail to Vancouver harbour where it will be loaded onto freight a shipped worldwide to battery manufactures. The cost of freight has been assumed to be covered under contracts with the purchaser.

A typical 20-foot shipping container has a load capacity of 21.7 tonnes per container. It has been assumed that 20 tonnes of product will be shipped per container. Using online databases, it was calculated to have a transport cost of CAD 1,500 per container from the proposed facility site to Vancouver Harbour.

Table 21-11. Product transport costs

Product	t LHM/container	Unit Cost (CAD)	CAD/tonne LHM
Lithium Hydroxide Monohydrate	20	$1,500/container	$75.0
Total			**$75.0**

21.2.9 Land Leasing

There are six surface leases associated with this project. Two north brine production pads, two south production pads, one injection pad and the central processing facility. The estimated area occupied by these leases is summarized in the table below.

Table 21-12. Land leasing costs

Description	CAD/tonne LHM
Total land leasing cost	**$25.5**

Lease costs vary throughout the province. Landowner consultation fees and annual lease costs were based on information provided by land companies familiar with costs in this area.

The pipeline right-of-ways for the production and injection pipelines will disturb a 15 to 20 m width of land for their full length. This may impact crop production along some of the routing. An allowance in the estimate has been made to compensate landowners for any disruption to the growing season this work may cause. Once re-seeded the pipeline right-of-way's will be brought back to pre-disturbance conditions.

21.2.10 General & Administration and Selling Costs

Description	CAD/tonne LHM
General & Administration	$25.0
Insurance and Marketing	$25.0
Total	**$100.0**

21.2.11 Operating Expenditures Summary

A summary of the projects operating costs are provided below.

Table 21-13. Operating Costs

Operating Costs	Description	Total Annual Costs (M CAD)	Cost Per Tonne LHM (CAD)	Total Annual Costs (M USD)	Cost Per Tonne LHM (USD)
Brine Production	Well, pumps and pipeline (Incl. Power)	$25.8	$1,288	$19.1	$954
Brine Pre-Treatment	H_2S Removal (Incl. Power)	$26.9	$1,341	$19.9	$993
DLE Process (Li-IX)	Primary extraction of lithium from the brine (Incl. Power)	$11.2	$559	$8.3	$414
Lithium Production	Concentration, Polishing, Electrolysis and Crystallization (Incl. Power)	$15.3	$761	$11.3	$564
Site, Labour and G&A	Power, Site, Transport, Labour and G&A Costs	$19.7	$988	$14.6	$732
Total		**$98.8**	**$4,936**	**$73.2**	**$3,656**

A total operating cost of CAD 98.8 Million per year, or CAD 4,936 per tonne LHM, are broken out by each major project step and are inclusive of direct and indirect costs. The majority of the operating costs are associated with reagents required within the system and power consumption.

22 Economic Analysis

22.1 General

A preliminary economic analysis of the Clearwater Lithium Project was completed using a Discounted Cash Flow (DCF) model to estimate the value of the project based on projected future cash flows. The basis for the DCF model is summarized as follows:

- Discount rate of 8% per year used to discount all future cashflows.
- Unlevered basis, which assumes that the project is financed from the Company'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 2020 dollars with no provision for inflation or escalation of costs or revenue.
- Applicable taxes and royalties have been accounted for in the analysis and are discussed in more detail below.
- A constant battery grade lithium hydroxide monohydrate sale price of CAD 19,007 has been used for the duration of the project, as described in Section 19 Market Studies and Contracts.
- Base case technical and economic outputs of the Clearwater Lithium Project described in this Report have been incorporated including rates, and CAPEX and OPEX estimates.
- All amounts are shown in Canadian dollars (CAD) unless otherwise specified.

A sensitivity analysis of the impact of variation of key technical and economic inputs on the project's Net Present Value (NPV) and Internal Rate of Return (IRR) has been included.

This preliminary economic assessment is preliminary in nature, includes inferred mineral resources that are considered too speculative geologically to have the economic considerations applied to them that would enable them to be categorized as mineral reserves, and there is no certainty that the preliminary economic assessment will be realized.

22.2 Principal Assumptions

22.2.1 Key Economic Assumptions

Key economic assumptions used in this economic analysis are outlined in Table 22-1. The battery grade lithium hydroxide monohydrate sale price shown below has been used for the duration of the project. The justification for this price forecast is described in Section 19 Market Studies and Contracts of this Report.

Table 22-1. Key Economic Assumptions

Parameter	Unit	Base Case Value (CAD)	Base Case Value (USD)
Lithium hydroxide monohydrate forecast price (FOB)	$/tonne	19,007	14,079
Discount Rate	% per year	8%	8%
Foreign Exchange Rate	CAD/USD	1.35	1.35

22.2.2 Key Technical Assumptions

Key technical assumptions used in this economic analysis are outlined in Table 22-2. These inputs to the economic analysis have been described in previous sections of this Report. The average brine grade presented is consistent with the inferred mineral resource reported.

Table 22-2. Key Technical Assumptions

Parameter	Unit	Base Case Value (CAD)	Base Case Value (USD)
Production	tonnes/year $LiOH.H_2O$	20,000	20,000
Average Brine Grade	mg/L Li	74.6	74.6
Design Brine Production Rate	m^3/day	140,000	140,000
Project Life	years	20	20
Total Capital Cost (CAPEX)	M $	959.4	710.7
Total Initial Capital	M $	812.7	602.0
Average Annual Operating Costs (OPEX)	M $/year	98.8	73.2
Cash Operating Costs	$/tonne $LiOH.H_2O$	4,936	3,656

22.3 Cash flow forecasts

Annual cash flow forecasts including revenue, and capital and operating expenses for the base case are provided in Table 22-3.

Table 22-3. Annual cash flow model

		Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Final Product																								
Produced LiOH·H2O	**t/year**				**20,015**	**20,015**	**20,015**	**20,015**	**20,015**	**20,015**	**20,015**	**20,015**	**20,015**	**20,015**	**20,015**	**20,015**	**20,015**	**20,015**	**20,015**	**20,015**	**20,015**	**20,015**	**20,015**	**20,015**
OPEX per Year																								
Brine Production and Disposal	CAD M$/year				24	24	24	24	25	26	25	26	26	26	27	27	27	27	27	27	27	27	27	27
Pre Treatment	CAD M$/year				28	27	27	27	27	28	27	27	27	27	27	28	27	27	27	27	27	28	27	27
Li Extraction (IX)	CAD M$/year				20	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Polishing	CAD M$/year				4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
LiOH·H2O Production	CAD M$/year				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
General OPEX	CAD M$/year				20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Total OPEX per Year	**CAD M$/year**				**107**	**96**	**97**	**97**	**97**	**99**	**98**	**98**	**98**	**99**	**99**	**100**	**99**	**99**	**99**	**99**	**99**	**100**	**99**	**99**
Revenue																								
Product Revenue	**CAD $M/year**				**380**	**380**	**380**	**380**	**380**	**380**	**380**	**380**	**380**	**380**	**380**	**380**	**380**	**380**	**380**	**380**	**380**	**380**	**380**	**380**
CAPEX																								
Brine Production & Injection	CAD $M			260	2	6	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Pre-Treatment	CAD $M			159	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chemical Plant CAPEX	CAD $M			238	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General CAPEX	CAD $M			47	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CAPEX Subtotal	**CAD $M**			**705**	**2**	**6**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**
Capital Contingency 25%	CAD $M			108	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total CAPEX	**CAD $M**			**813**	**2**	**6**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**
Financials																								
Annual EBITDA	CAD $M/year				273	284	284	284	283	281	283	282	282	282	282	281	282	282	282	282	282	280	282	282
Royalties																								
Royalty Paid	CAD $M/year			-	4	4	4	21	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Tax																								
Income tax	CAD $M/year			-	19	33	40	42	43	46	49	50	52	53	53	54	54	54	55	55	55	55	55	55
Unlevered Cash Flow																								
Pre-Tax Operating Cashflow	**CAD $M/year**			**-**	**270**	**280**	**280**	**263**	**249**	**248**	**249**	**249**	**248**	**248**	**248**	**247**	**248**	**248**	**248**	**248**	**248**	**246**	**248**	**248**
After-Tax Operating Cashflow	**CAD $M/year**			**-**	**251**	**248**	**240**	**220**	**206**	**201**	**200**	**198**	**197**	**195**	**195**	**193**	**194**	**193**	**193**	**193**	**193**	**192**	**193**	**193**
Pre-Tax Cashflow	**CAD $M/year**			**- 813**	**267**	**275**	**272**	**255**	**242**	**240**	**241**	**241**	**241**	**240**	**240**	**239**	**240**	**240**	**240**	**240**	**240**	**239**	**240**	**240**
After-Tax Cashflow	**CAD $M/year**			**- 813**	**248**	**242**	**232**	**213**	**198**	**194**	**192**	**190**	**189**	**188**	**187**	**186**	**186**	**186**	**185**	**185**	**185**	**184**	**185**	**185**

22.4 Taxes, Royalties, and Other Government Levies or Interests

Alberta crown royalties for metallic and industrial minerals are set at 1% gross mine-mouth 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 3.4 years in the case of this Report.

A blended Federal and Provincial income tax rate of 23% was utilized to calculate the projected income taxes payable. To calculate after tax income for the project, deductions with respect to capital expenditures incurred were utilized including the use of Canadian Development Expense, Capital Cost Allowances and non-capital loss carry forward.

22.5 NPV, IRR, and payback period

A summary of the key base case economic outputs from the economic analysis is provided in Table 22-4.

Table 22-4. Key economic outputs

Parameter	Unit	Base Case Value (CAD)	Base Case Value (USD)
Production	tonnes/year $LiOH.H_2O$	20,000	20,000
Project Life	years	20	20
Lithium hydroxide monohydrate forecast price (FOB)	$/tonne $LiOH.H_2O$	19,007	14,079
Total Capital Cost (CAPEX)	M CAD	959.4	710.7
Total Initial Capital	M CAD	812.7	602.0
Average Annual Operating Costs (OPEX)	M CAD	98.8	73.2
Cash Operating Costs	$/tonne $LiOH.H_2O$	4,936	3,656
Discount Rate	% per year	8%	8%
Pre-Tax NPV$^{8\%}$	M $	1,516.1	1,123.1
After-Tax NPV$^{8\%}$	M $	1,106.8	819.9
Pre-Tax IRR	%	32%	32%
After-Tax IRR	%	27%	27%
Pre-Tax Payback Period	years	3.0	3.0
After-Tax Payback Period	years	3.4	3.4

This preliminary economic assessment is preliminary in nature, includes inferred mineral resources that are considered too speculative geologically to have the economic considerations applied to them that would enable them to be categorized as mineral reserves, and there is no certainty that the preliminary economic assessment will be realized.

22.6 Sensitivity Analysis

A sensitivity analysis was carried out by varying single parameters between -30% and +30% of each parameter's base case input value. Each of the three parameters, $LiOH.H_2O$ price, OPEX, and CAPEX were varied separately to isolate their impact on the projected $NPV^{8\%}$ and IRR. The analysis was completed under both pre- and after-tax conditions.

Results of the sensitivity analysis are shown graphically in Figure 22-1 to Figure 22-4.

The sensitivity analysis indicates that, within the ±30% bounds relative to the base case, product pricing ($LiOH.H_2O$) has the most significant impact on the Clearwater Lithium Project's $NPV^{8\%}$. Based on this analysis, the IRR, both pre and after tax, is relatively sensitive to both capital cost (CAPEX) and product pricing ($LiOH.H_2O$).

Breakeven points of $NPV^{8\%}$ = 0 and IRR = 8% were not reached within the within the ±30% bounds relative to the base case considered in this analysis.

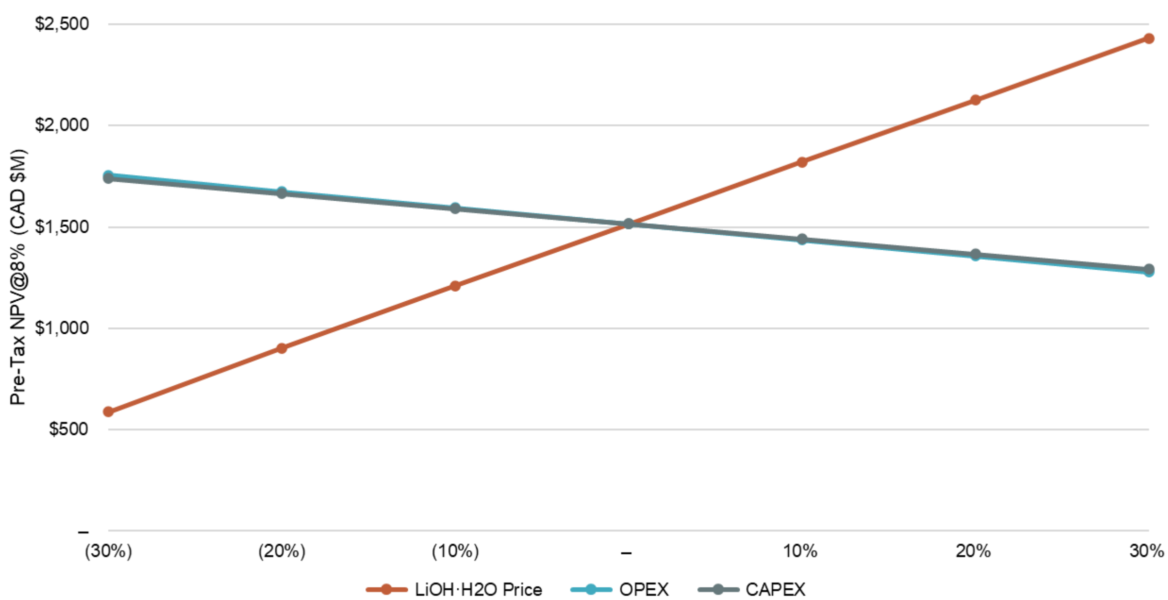

Figure 22-1. Pre-Tax $NPV^{8\%}$ Sensitivity Analysis (CAD M)

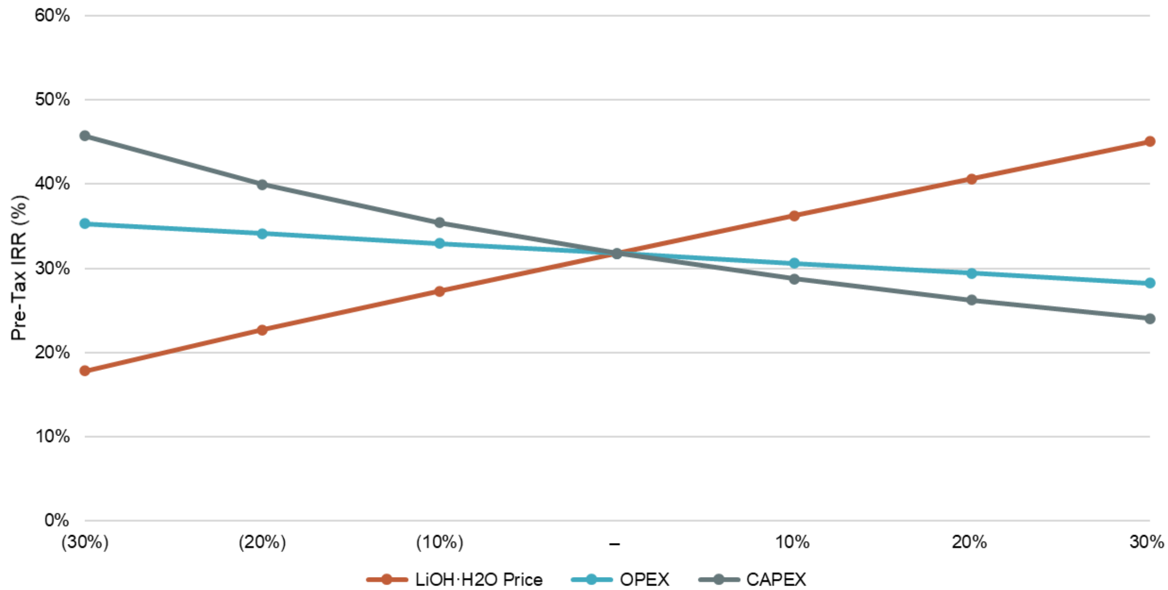

Figure 22-2. Pre-Tax IRR Sensitivity Analysis (%)

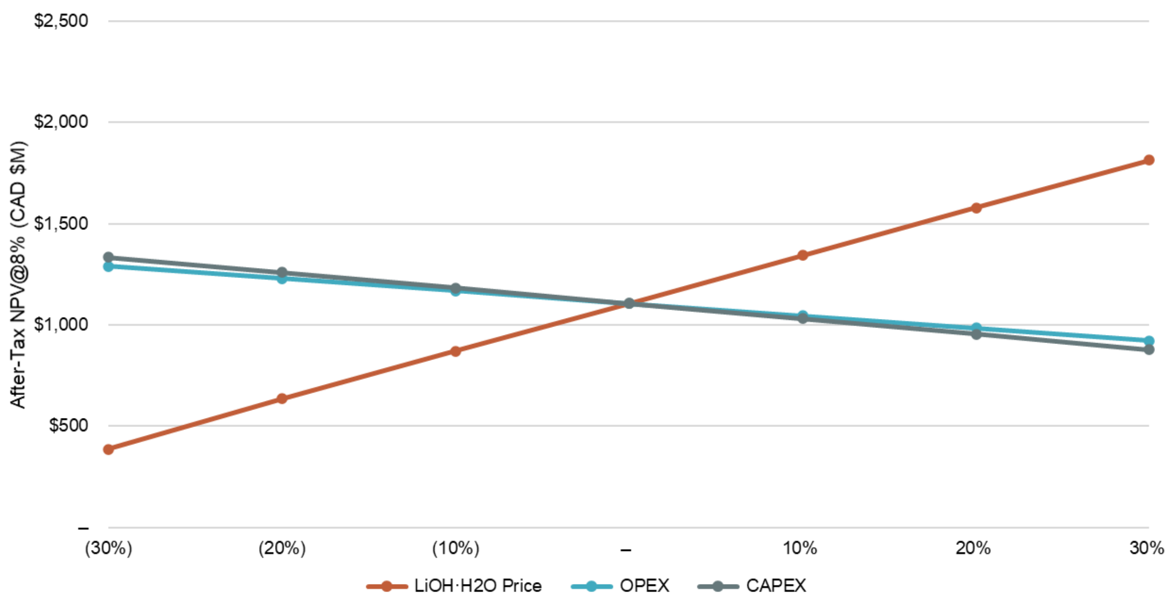

Figure 22-3. After-Tax NPV$^{8\%}$ Sensitivity Analysis (CAD M)

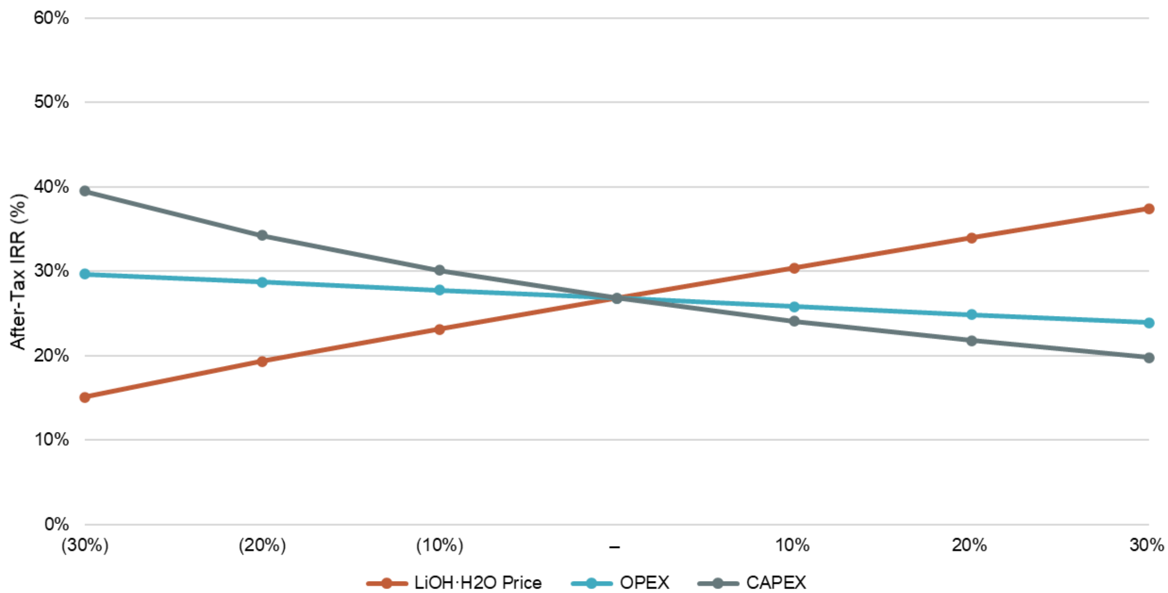

Figure 22-4. After-Tax IRR Sensitivity Analysis (%)

23 Adjacent Properties

An adjacent property is defined as a reasonably proximate property in which the issuer does not have an interest and has similar geological characteristics to those of the subject of this Report. Alberta is currently experiencing an increased level of industry interest in its Li-brine potential. A variety of exploration companies have staked permits throughout Alberta; this includes areas with historical instances of lithium-in-brine enrichment in addition to areas with equivalent or associated Devonian Formations present.

The Clearwater claims are interspersed in a checkerboard configuration between permits held from the provincial government and those privately-owned, freehold land. On freehold lands, metallic and industrial minerals are owned by private individuals or corporations. Production from within the permit area is expected to be governed by similar regulations that govern oil and gas production in the province. Outside of the permit areas (large white areas on Figure 23-1), the lands are held by a combination of Freehold and Crown ownership.

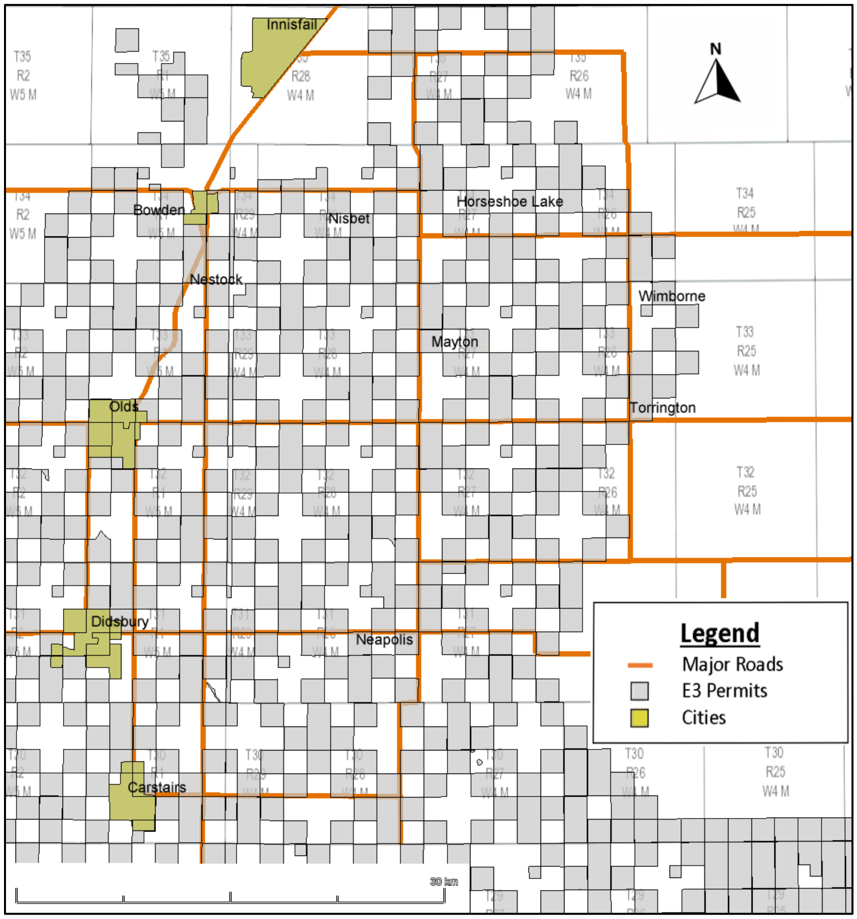

Figure 23-1. Adjacent Properties Map

24 Other Relevant Data and Information

24.1 Lithium Regulation in Alberta

The current policy regulation for the production of lithium in Alberta is being defined. E3 Metals assumes that current oil and gas regulations and Directives would be applicable and may potentially guide the operational aspects of lithium resource production.

In order to produce lithium dissolved in brine, E3 must produce the brine water from the subsurface pore space. According to Alberta regulation, both pore space and water are resources owned wholly by the Crown. A water source well or injection well licensed under Directive 56 would allow for the production and injection of brine through pore space. In E3's case, this is the preferred pathway to well licenses for the purpose of extracting lithium.

E3 expects that pooling agreements would apply for the extraction of lithium as they do for oil and gas under the Oil and Gas Conservation Act[18]. This is because lithium occurs dissolved in the brine and must be produced as a fluid over a relatively large area, beyond traditional Drill Spacing Units (DSU). In this circumstance, E3 would apply under Directive 65[19] to accommodate possible amendments to the spacing of well configurations and/or well placement that may be required to produce water at volumes required to extract lithium.

Existing synergies between lithium brine production and oil and gas, including the re-injection of lithium disposal water for strategic pressure support beneath oil and gas fields, could provide a mutual benefit for both lithium extraction and oil and gas production. Co-located operations could evolve in a symbiotic approach that ideally would contribute to each industry's success. This may involve the limitation of re-injection or disposal of oilfield wastewater in an area near to E3's unproduced mineral permit area to limit the dilution of the lithium resource. It is expected that MRLs (maximum rate limitations), designed to optimize oil production, could be avoided or negotiated through collaborative effort and industry partnerships.

24.2 Health, Safety and Environment

There are inherent health and safety considerations associated with lithium project development in Alberta, including well development and all field activities (construction, drilling, completions, workovers and operations) in the presence or potential presence of hydrogen sulphide gas (H_2S).

E3 Metals' employee handbook contains Health Safety and Environment protocols consistent with the Company's current stage of development. H_2S Alive training is required for all field activities. As the project develops further, the Company plans to ensure all aspects of the development and operation conduct and follow safe work practices across all activities with particular focus on the field. Design considerations will be made to protect safety of people and the environment. This includes implementing a corrosion inhibition program and safety protocols for sour services. These programs are well defined for oil and gas operators in the area.

25 Interpretation and Conclusions

25.1 Resource Estimate and Brine Production

The inferred mineral resource estimate for the Clearwater Resource Area has been updated to 410,000 tonnes of elemental lithium, an increase of 14% from the initial resource estimate in 2017. Using a conversion factor of 5.323, this equates to 2,200,000 tonnes of lithium carbonate equivalent (LCE). Several factors contributed the updated estimate, including: 1) an expansion of the resource area by 85 km^2 based on additional permits E3 Metals acquired since the initial resource estimate in 2017; 2) new and repeated

[18] https://www.aer.ca/documents/actregs/ogc_reg_151_71_ogcr.pdf
[19] https://www.aer.ca/documents/directives/Directive065.pdf

sampling within the resource area has resulted in an updated average concentration of 74.6 mg/L Li; and 3) updated well network modeling has outlined the ability for the reservoir to produce a larger amount of lithium from brine than was originally envisioned, increasing the production factor from 50% to 80% in some areas.

The resource is classified as inferred because geological evidence is sufficient to imply but not verify geological, grade or quality continuity. It is reasonably expected that the majority of the Inferred Mineral Resource Estimate could be upgraded to Indicated or Measured Mineral Resources with continued exploration.

Based on the large amount of geological data available from oil and gas operations in the Clearwater Resource Area, it is expected that lithium grade is consistent throughout the Clearwater Resource Area and that a series of wells, drilled specifically for the production of brine, would be capable of delivering 3,300 m^3/day per well. At an average grade of 74.6 mg/L lithium, the project will move just over 128,000 m^3/day of brine, with additional well production capacity in excess of this. As Direct Lithium Extraction (DLE) processing does not evaporate the water contained within the brine, the lithium void brine is returned to the aquifer through a series of injection wells. This re-injection of lithium depleted brine will serve to maintain pressures and brine production rates in the aquifer. The brine production process step also includes pre-treatment for removal of H_2S from the brine prior for delivery to the Direct Lithium Extraction (DLE) process.

25.2 Lithium Processing / Production

There are several stages included in this process step designed to deliver battery quality lithium hydroxide. The first step includes further concentration of the Li-IX solution, followed by polishing steps to remove the remaining impurities. The ultrapure lithium brine solution is then fed into electrolysers where lithium hydroxide solution is formed. From there, the lithium hydroxide solution is crystalized into lithium hydroxide monohydrate crystal which is packaged and transported to a nearby rail network where it can be transported to eastern and western shipping ports for international distribution, or south for sale directly into the American market.

25.3 Economics

A summary of the projects capital and operating costs are provided below. The full project summary of costs and the economic valuation based on the yearly production of 20,000 tonnes of LHM are detailed based on the capital and operating costs.

Table 25-1. Capital Costs

Capital Costs	Description	Costs (M CAD)	Costs (M USD)
Brine Production	Wells, pumps and pipelines	260.3	192.8
Brine Pre-Treatment	H_2S Removal	159.0	117.8
DLE Process (Li-IX)	Primary extraction of lithium from the brine	21.1	15.6
Lithium Production	Concentration, Polishing, Electrolysis and Crystallization	217.2	160.9
Power, Site, Transport and Labour Costs	Misc. Site and labour costs	47.4	35.1
Contingency (25%)	Applied to direct capital costs	107.7	79.8
Total		**812.7**	**602.0**
Sustaining Capital	Pump replacement, etc.	146.7	108.7

The total initial capital cost of the Project for 20,000 tonnes per year production of LHM is estimated at USD 602.0 Million, inclusive of direct and indirect costs and contingency. In addition, USD 108.7 Million of sustaining capital is also estimated, with the majority of this cost associated with the replacement of brine production pumps.

Table 25-2. Operating Costs

Operating Costs	Description	Total Annual Costs (M CAD)	Cost Per Tonne LHM (CAD)	Total Annual Costs (M USD)	Cost Per Tonne LHM (USD)
Brine Production	Well, pumps and pipelines (Incl. Power)	25.8	1,288	19.1	954
Brine Pre-Treatment	H_2S Removal (Incl. Power)	26.9	1,341	19.9	993
DLE Process (Li-IX)	Primary extraction of lithium from the brine (Incl. Power)	11.2	559	8.3	414
Lithium Production	Concentration, Polishing, Electrolysis and Crystallization (Incl. Power)	15.3	761	11.3	564
Site, Labour and G&A	Power, Site, Transport, Labour and G&A Costs	19.7	988	14.6	732
Total		**98.8**	**4,936**	**73.2**	**3,656**

A total operating cost of USD 73.2 Million per year, or USD 3,656 per tonne LHM, are broken out by each major project step and are inclusive of direct and indirect costs. The majority of the operating costs are associated with reagents required within the system and power consumption.

Table 25-3. Preliminary Economic Assessment Results

Description	Units	CAD	USD
Production	tonnes/year LHM	20,000	20,000
Project Life	Years	20	20
Total Capital Cost (CAPEX)	M $	959.5	710.7
Total Initial Capital	M $	812.7	602.0
Average Annual Operating Costs (OPEX)	M $/year	98.8	73.2
Average Selling Price (LHM)	$/tonne LHM	19,007	14,079
Cash Operating Costs	$/tonne LHM	4936	3,656

Description	Units	CAD	USD
Average Annual EBITDA	$	281.6	208.6
Pre-Tax Net Present Value ("NPV") (8% discount)	$	1,516.2	1,123.1
After-Tax Net Present Value ("NPV") (8% discount)	$	1,106.9	819.9
Pre-Tax Internal Rate of Return ("IRR")	%	32%	32%
After-Tax Internal Rate of Return ("IRR")	%	27%	27%
Payback Period (After-Tax)	years	3.4	3.4

This preliminary economic assessment is preliminary in nature, includes inferred mineral resources that are considered too speculative geologically to have the economic considerations applied to them that would enable them to be categorized as mineral reserves, and there is no certainty that the preliminary economic assessment will be realized.

25.4 Risk Analysis

The risks identified pertain to the Company's ability to deliver the project as set forth in this document and are outlined in the following table. A high project risk means that a change would have a serious impact to E3's ability to deliver the project technically or within the estimated operating and capital assumptions made. A low project risk means that a big change would have a minimal impact on E3's ability to deliver the project technically or within the estimated operating and capital assumptions made.

Table 25-4. Project Risk Matrix

Risk #	Risk Description	Existing Controls (Design features incorporated into the preliminary design to mitigate the risk)	Initial Risk	Risk Treatment Plan	Residual Risk
		RISK MATRIX – GEOLOGY AND BRINE DELIVERY			
1	Actual resource size is different than the estimate	Ongoing geoscience development	Low	Evaluation of geophysical data and enhanced geological analysis to develop a more detailed geological model and resource estimate.	Low
2	Dissolved gas content is different than expected	Planned 2021 sampling program	Medium	Collect and analyze pressurized samples away from hydrocarbon production during flow testing to confirm estimates.	Low
3	Brine production and injection rates or aquifer connectivity deviates from expectations	Planned 2021 aquifer flow testing program	High	Advanced geological mapping and modelling to further develop aquifer characterization (included in plans to upgrade to M&I); Flow testing and pressure monitoring within the CCRA. In new wells, collect core, run image logs, capture fluid samples, conduct flow/injection tests to evaluate reservoir parameters; Analyze core data to characterize fines migration; Confirm design parameters against new data.	Medium

Risk #	Risk Description	Existing Controls (Design features incorporated into the preliminary design to mitigate the risk)	Initial Risk	Risk Treatment Plan	Residual Risk
4	Well integrity failure	No current controls	Low	Proactively manage well integrity as per oil and gas operating standards. Conduct study of wells in area to understand gas migration risks; adjust cement design or placement of intermediate casing based on learnings from gas migration study; implement corrosion inhibition program.	Low
5	Pump reliability and ESP failure rate not as expected	No current controls	Medium	Monitor failure rate and change pump design if needed; Continuously verify pump design based on new well data	Low
6	Downhole drilling collision	No current controls	Low	Conduct industry standard anti-collision evaluation of area wells and ensure drilling plan uses this data for each wellpad once locations are firm; Use of directional tools to monitor while drilling to ensure collision risk is mitigated; well design to space wells out to mitigate collision.	Low

Risk #	Risk Description	Existing Controls (Design features incorporated into the preliminary design to mitigate the risk)	Initial Risk	Risk Treatment Plan	Residual Risk
7	Well Pad Access	Planned stakeholder engagement for 2021	Medium	Ensure final location is sited using existing maps to accommodate each well pad with existing surface structures and considers stakeholder input; Update directional well plan when siting is complete to ensure well plan is feasible with consideration of anti-collision; Conduct land survey early for siting preparation; Early engagement with local stakeholders and landowners.	Low
8	Simultaneous operations create project delays when activities are planned at the same time.	No current controls	Low	Ensure a Simultaneous Operations (SIMOPS) plan is prepared and followed for safe concurrent operations in order to effectively optimize the project schedule. Include construction, drilling, completions, facilities, roads, pipelines, and commissioning.	Low
RISK MATRIX – PIPELINE AND PRE-TREATMENT					
9	Power requirements for CPF and well pads cannot be met by service provider.	Discussions have been initiated with service providers to plan for transmission and distribution upgrades required for E3 facilities	Medium	Continue discussions with service providers so they can start planning for infrastructure upgrades. Initiate an application with Alberta Energy System Operator (AESO) to start power systems modelling.	Low

Risk #	Risk Description	Existing Controls (Design features incorporated into the preliminary design to mitigate the risk)	Initial Risk	Risk Treatment Plan	Residual Risk
10	Line power prices increase above the expected CAD 0.05/kW-hr resulting in higher-than-expected OPEX.	Discussions have been initiated with service providers to determine pricing. This has resulted in the estimated cost used in the PEA.	High	Continue discussions with service providers with the goal of negotiating a long-term service contract.	Medium
11	Natural gas prices increase above the expected CAD 4.09/GJ resulting in a higher-than-expected OPEX.	Review gas supply websites to determine current long term gas prices.	Medium	Initiate discussions with service providers to project 20-year gas prices for a project this size.	Medium
12	Natural gas volumetric requirements cannot be met by service provider.	No current controls	Low	Initiate discussions with service providers to confirm availability of required volumes on a long-term basis. Initiate discussions with alternative power sources (e.g., renewables).	Low
13	Quantity of ozone required for H_2S polishing is higher than expected resulting in larger equipment requirements and higher power draw. This would lead to higher CAPEX and OPEX.	Discussions with ozone equipment vendor have been initiated to review scope of project.	Low	Include ozone generation and injection to remove H_2S in pilot project.	Low

Risk #	Risk Description	Existing Controls (Design features incorporated into the preliminary design to mitigate the risk)	Initial Risk	Risk Treatment Plan	Residual Risk
14	Pipeline routing need to be changed to accommodate landowner or other requests resulting in longer pipeline lengths and higher CAPEX.	Desktop routing was completed to avoid crossing farmers field at diagonals and follow crop fields	Low	Complete a survey and engage landowners in routing discussions.	Low
15	Power generation supplier will not provide a lease to own option resulting in higher-than-expected CAPEX.	Conversations were initiated with power generation suppliers. Lease to own options are currently available.	Medium	Engage companies specializing in financing large capital investments over a long term.	Low
16	United States to Canadian dollar exchange rate varies resulting in equipment manufactured in the US to be more expensive than expected increasing CAPEX	A USD to CAD exchange rate of 1.35 was used. This is a fairly conservative estimation based on historical data.	Low	None needed.	Low
RISK MATRIX – LITHIUM EXTRACTION AND PROCESSING					
17	Flowsheet is predicated on a sorbent particle that is still under development. Successful development of a "large" diameter sorbent particle is required for the flowsheet as shown.	Sorbent and process development occurring in parallel with several options identified as potential commercial solutions.	Medium	Risk is low that it will not be possible to develop a suitable bead. Risk is higher that "large" diameter sorbent performance will differ from sorbent used as sizing basis. Ongoing development and testing.	Low

Risk #	Risk Description	Existing Controls (Design features incorporated into the preliminary design to mitigate the risk)	Initial Risk	Risk Treatment Plan	Residual Risk
18	Sorbent bead performance (selectivity, loading capacity etc.) differs from performance observed in the lab.	Additional capacity has been allowed for in the preliminary IX circuit design. The cost implication of this additional capacity is relatively low.	Medium	Ongoing laboratory test work and development. Pilot scale demonstration for process performance and process optimisation.	Low
19	Removal efficiencies and mechanisms for secondary contaminants such as B, Sr and Mn are not quantified.	Existing design handles B, Sr and Mn through conventional means.	Medium	Further analysis and test work required to quantity and qualify trace secondary contaminants.	Low
20	Suitability of selected dewatering equipment and quantity for large volumetric brine flow rates in the IX circuit. Current design may require additional and/or parallel equipment.	Well established processes have been selected; however, flowrates are very high. No hydraulic analysis has been conducted at this time. Dewatering equipment is a relatively small component of overall capital cost.	Medium	Review equipment selection and conduct hydraulic analysis.	Low
21	Perceived unproven technology combination (IX – electrolysis – crystallisation) on lithium brine	Existing recycle streams (interaction between unit operations) have been modelled using sound kinetic/thermodynamic models.	Medium	Simulate entire process at pilot scale.	Low

26 Recommendations

26.1 Resource and Aquifer Characterization

Characterization of the aquifer geology and properties benefits from an abundance of data compiled by the oil and gas industry. To better characterize the potential brine production from this project, additional data and further characterization of existing data is required to: further characterize the aquifer; upgrade the resource to a Measured or Indicated Mineral Resource; refine production well networks; and refine injection well networks. Recommended activities include:

- Update the geologic mapping into facies-based hydrostratigraphic flow units;
- Collect additional information about the variation of aquifer properties and lithium concentrations with depth in the Leduc and Cooking Lake aquifers; and
- Complete pumping tests in the aquifer to better characterize aquifer properties on a spatial scale more representative of the design for future well networks.

This work is estimated to cost between CAD 1,500,000 and CAD 2,500,000 depending on the location and efficiency of field testing. It is anticipated that the work outlined above would support an upgrade of the majority of the resource to the "Indicated" and "Measured" categories.

26.2 Brine Delivery and Infrastructure

For well design purposes, understanding the fluid and rock characterization is very important for material selection, design components, and safe practices needed. There is data available near the E3 project that was collected for the purposes of oil and gas production, however, detailed analysis of the aquifer fluids in the E3 project area is needed to further define brine chemistry and H_2S content to confirm design parameters including pre-treatment. Rock particle size distribution testing is needed from a test well core in the project area to design the well completions, maintenance planning, and operational chemical programs. The cost of this work is estimated to be CAD 25,000 to CAD 90,000.

The assumptions for the well network cost estimation are based on the current market conditions, best available data for the planned well design, and scale of development. There are many optimizations that are possible to improve capital and operating costs. In the next project stages, optimization of the drilling program, well design, and pump design will provide an opportunity to reduce the overall program cost. An evaluation of this kind is expected to cost between CAD 20,000 to CAD 90,000 depending on scope.

Finally, continued engagement with the local transmission and distribution service providers and natural gas providers is required to increase the confidence of cost estimates for power and natural gas and confirm that the power requirements of the project can be met as per the estimates outlined in this Report.

26.3 Lithium Processing

The following need confirmation through additional test work and pilot scale testing:

- Confirm the sorbent performance, kinetic and equilibrium data;
- Optimization of the current IX system envisaged – compare the current “sorbent-in-brine” IX circuit with a fixed bed system;
- Quantify the removal efficiencies and species formed for secondary contaminants such as B, Sr and Mn removed in the secondary purification stage where impurities (largely Ca and Mg) are removed via precipitation. Simulate the system at lab scale; and
- Demonstrate the feasibility of the electrolysis process at pilot scale using Leduc brine.

The total estimated costs associated with this work are CAD 3,500,000 to CAD 5,000,000.

26.4 Summary of Recommendations

Table 26-1. Summary of Recommendations and Costs

Category	Brief Description	Costs (CAD)
Resource and Aquifer Characterization	Refine geoscience mapping of hydrostratigraphic units	$1,500,000 - $2,500,000
	Collect brine samples deeper in the aquifer	
	Flow test the aquifer; measure pressure response	
Brine Delivery and Infrastructure	Advanced fluid characterization, including dissolved gasses	$25,000 - $90,000
	Rock characterization for particle size distribution	
	Further engagement with local energy service providers (transmission, distribution, natural gas fuel)	
Lithium Processing	Finalize IX sorbent	$3,500,000 - $5,000,000
	Optimize IX system design	
	Quantify removal efficiency of impurities	
	Demonstrate feasibility of electrolysis process at pilot scale	

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Appendix A. Central Clearwater Resource Area Claims

Appendix Table A-1. Central Clearwater Resource Area Claims

Agreement No	Property	Representative	Zone description		Term date	Expiry date	Area (ha)	2 Year Expenditure Commitment	Year Commitment Due
9316060174	Clearwater	1975293 Alberta Ltd.	4-27-030:	20; 29; 30; 32	2016-06-20	2030-06-20	9088	$90,880.00	2021
			4-27-031:	2; 4; 6; 10-12; 14; 16; 22; 24; 26NE; 28; 29; 34; 36					
			4-27-032:	2; 4; 10-12; 14; 16; 22; 24; 26NE; 28; 34; 36					
			4-28-030:	36					
9316060175	Clearwater	1975293 Alberta Ltd.	4-26-033:	4; 6; 16; 18; 20; 28-30; 32	2016-06-20	2030-06-20	9024	$90,240.00	2021
			4-26-034:	2; 4; 6; 10; 11; 14; 16; 18; 20; 22; 28-30; 32					
			4-27-033:	2; 4; 10-12; 14; 16; 22; 24; 26NE; 28; 34; 36					
9316060176	Clearwater	1975293 Alberta Ltd.	4-28-033:	2; 4; 6; 10-12; 14; 16; 18; 20; 22; 24; 26NE; 28-30; 32; 34; 36	2016-06-20	2030-06-20	8618.3	$86,182.96	2021
			4-29-033:	2EF; 11EF; 12; 14EF; 24; 26NEF; 36S,NE					
			5-01-033:	2; 4; 6; 10-12; 14; 16; 18; 20; 22; 24					
9316060177	Clearwater	1975293 Alberta Ltd.	4-27-034:	2; 4; 6; 10-12; 14; 16; 18; 20; 22; 24; 26NE; 27SWP; 28-30; 32; 34; 36	2016-06-20	2030-06-20	8768.2	$87,682.00	2021
			4-28-034:	2; 4; 6; 10-12; 14; 16; 18; 20; 22; 24; 26NE; 28S,NE; 29S; 30S; 36					
			4-29-034:	24					
9316060178	Clearwater	1975293 Alberta Ltd.	4-29-034:	2EF; 11EF; 12; 14EF; 26NEF	2016-06-20	2030-06-20	7944.764	$79,447.64	2021
			5-01-033:	26NE; 28-30; 32; 34; 36					
			5-01-034:	2; 4; 6; 10-12; 14; 16; 18; 20; 22; 24; 26NE; 28NW,L1,L2; 29; 30; 34; 36					
			5-01-035:	2; 4S; 6S; 10-12; 14; 16; 18E; 20S; 22S,NE; 28SE,NW; 29					
9317060215	Clearwater	1975293 Alberta Ltd.	4-27-031:	18; 20; 30; 32; 33N	2016-06-20	2031-06-20	4992	$49,920.00	2022
			4-28-031:	12; 14; 16; 18; 20; 22; 24; 25N,SE; 26NE					
			4-29-031:	36					
9317606216	Clearwater	1975293 Alberta Ltd.	4-27-032:	6; 18; 20; 29; 30; 32	2017-06-20	2031-06-20	8695.404	$86,954.04	2022
			4-27-033:	6; 18; 20; 29; 30; 32					

Agreement No	Property	Representative	Zone description		Term date	Expiry date	Area (ha)	2 Year Expenditure Commitment	Year Commitment Due
			4-28-032:	1NEP; 2; 4; 6; 10-12; 14; 16; 18; 20; 22; 24; 26NE; 28-30; 32; 34; 36					
9317060219	Clearwater	1975293 Alberta Ltd.	4-28--031	2; 4; 6; 8NW; 10; 11	2019-06-19	2031-06-20	8189.08	$81,890.80	2022
			4-29-031:	2EF; 11EF; 12; 14EF; 24; 26NEF.					
			5-01-031:	2; 4; 6; 10-12; 14; 16; 18S, NE, L14; 20; 22; 24; 26NE; 28-30; 32; 34; 36					
			5-02-031:	2; 11; 12; 14; 24; 36					
9317060220	Clearwater	1975293 Alberta Ltd.	5-01-032:	2; 4; 6; 7SP; 10-12; 14; 16; 18; 20; 22; 24; 26NE; 28-30; 32S, NW,L9,L10,L16; 34; 36	2016-06-20	2031-06-20	9097.2	$90,972.00	2022
			5-02-031:	4; 6; 10; 16; 18; 20; 22; 26NE; 28-30; 32; 34					
			5-02-032:	2; 4; 6					
			5-03-032:	12; 24					
9317060238	Clearwater	1975293 Alberta Ltd.	4-27-030:	4; 6; 16; 18; 21SP,NWP; 22; 28; 34	2016-06-20	2031-06-20	4367.48	$43,674.80	2022
			4-28-030:	2; 4; 6; 10-12; 14; 16; 18; 20					
9318050395	Clearwater	1975293 Alberta Ltd.	4-25-033:	18; 30	2018-05-25	2032-05-24	3648.8	$18,244.00	2021
			4-26-032:	28; 34					
			4-26-033:	2; 10-12; 12; 22; 24; 26NE; 34; 35NEP; 36					
			2-26--34:	12					
9319100157	Clearwater	1975293 Alberta Ltd.	4-26-030:	6; 7; 9; 10; 16-20; 30	2016-06-20	2030-06-20	7424	$37,120.00	2021
			4-26-031:	6; 18; 20; 29; 30; 32					
			4-26-032:	4; 6; 10; 16; 18; 20					
			4-27-030:	2; 10-12; 14; 24; 36					
9320100056	Clearwater	1975293 Alberta Ltd.	5-02-033:	22; 24; 26NE; 34; 36	2016-06-20	2030-06-20	2368	$11,840.00	2022
			5-02-034:	2; 11; 12; 14; 24					
							Sum	**$855,048.24**	