LithiumBank Resources Corp.

NI 43-101 TECHNICAL REPORT

Preliminary Economic Assessment (PEA)

FOR LITHIUMBANK RESOURCES BOARDWALK LITHIUM-BRINE PROJECT IN WEST-CENTRAL ALBERTA, CANADA

Prepared By:	Hatch Ltd. GLJ Ltd. Fluid Domains APEX Geoscience Ltd. Scott Energy Inc. Go2Lithium	Prepared for:	LithiumBank Resources Corp.
		Effective Date:	22 February 2024
		Project No.	H367159

2024 · Alberta, Canada

IMPORTANT NOTICE TO READER

This report was prepared by the qualified persons (QPs) listed in Table 2-1. Each QP assumes responsibility for those sections or areas of this report that are referenced with their name in Table 2-1. None of the QPs, however, accept any responsibility or liability for the sections or areas of this report that were prepared by other QPs. This report was prepared to allow LithiumBank Resources Corp. (the “Owner”) to reach informed decisions respecting the development of the Boardwalk Project. Except for the purposes legislated under provincial securities law, any use of this report by any third party is at that party’s sole risk, and none of the contributors shall have any liability to any third party for any such use for any reason whatsoever, including negligence. This report is intended to be read as a whole, and sections should not be read or relied upon out of context. This report contains estimates, projections, and conclusions that are forward-looking information within the meaning of applicable securities laws. Forward-looking statements are based upon the responsible QP’s opinion at the time that it was made; however, most cases involve significant risk and uncertainty. Despite the diligent efforts of each responsible QP to identify factors that could potentially result in significant deviations between actual events or results and the descriptions provided in this report, the existence of other factors cannot be discounted, which may lead to unanticipated, underestimated, or non-projected events or results. None of the QPs undertake any obligation to update the forward-looking information. As permitted by Item 3 of Form 43-101F1, the QPs have, in the preparation of this report, relied upon certain reports, opinions and statements of certain experts and the Owner. These reports, opinions and statements, the makers of each such report, opinion or statement and the extent of reliance is described in Section 3 of this report. Each of the QPs hereby disclaims liability for such reports, opinions, and statements to the extent that they have been relied upon in the preparation of portions of this report, as described in Section 3. None of the QPs undertake any obligation to update any information contained in this report, including, without limitation, any forward-looking information.

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1. Summary

1.1 Introduction

LithiumBank Resources Corp. (LithiumBank) is an exploration and development company focused on developing their flagship Boardwalk Property, based in west-central Alberta, Canada. This project is based on a lithium hydroxide monohydrate plant which utilizes direct lithium extraction (DLE). The processing facility receives treated lithium brine from within a brine well-field. The brine is treated using DLE, utilizing Go2Lithium's DLE technology, where lithium is selectively extracted from the brine. Post DLE, the concentrated lithium brine stream undergoes further processing steps including purification, concentration, and conversion to produce commercial battery grade lithium hydroxide monohydrate.

This report has been compiled by Hatch Ltd. (Hatch) for LithiumBank with input from the following independent consultants:

- APEX Geoscience Ltd.
- Fluid Domains.
- GLJ Ltd.
- Hydrogeological Consultants Ltd.
- Scott Energy Inc.
- Go2Lithium

The Qualified Person (QP) responsible for each section and the authors for each section are disclosed in Section 2.2. This report is compliant with National Instrument 43-101 (NI 43-101) disclosure standards for mineral projects in Canada.

1.2 Property Description and Ownership

The Boardwalk Property is in west-central Alberta, Canada, directly south and west of the Town of Valleyview, approximately 85 km east of the City of Grande Prairie and 270 km northwest of the City of Edmonton.

The Boardwalk Property is comprised of 26 combined Rock-Hosted Mineral Permits and Brine-Hosted Mineral Licences that collectively form a contiguous package of land that totals 170,424 hectares. The permits were acquired directly from the Government of Alberta through the Provinces on-line mineral tenure system. LithiumBank has 100% ownership of the mineral rights at the Boardwalk Property. The mineral permits/licences encompass the Sturgeon Lake Reef Complex and Late Devonian Leduc Formation reservoir, or brine aquifer.

The Property can be accessed by provincial highways and secondary one- or two-lane all-weather roads. Access within the property is further facilitated by numerous all-weather and dry weather gravel roads and tracks, many of which are serviced year-round due to oil and gas exploration in the area.

1.3 Mineral Resource Estimates

Updated Boardwalk Leduc Formation Li-brine resource estimations are presented in this, the current technical report, due to a revision of the property land area since LithiumBank's last Boardwalk technical report (Effectively Dated June 16, 2023). The updated Li-brine resource estimations are classified as indicated and inferred mineral resources in accordance with the Canadian Institute of Mining, Metallurgy and Petroleum definition standards and best practice guidelines (2014, 2019) and the Canadian Securities Administration's Standards for Disclosure of Mineral Projects, National Instrument 43-101.

The indicated and inferred Boardwalk Leduc Formation Li-brine resource estimations are presented as a total (or global value), and were estimated using the following relation in consideration of the Leduc Formation aquifer brine:

- Lithium Resource = Total Brine Aquifer Volume X Average Porosity X Percentage of Brine in the Pore Space X Average Concentration of Lithium in the Brine.

The indicated mineral resource area is defined by the outline of the Sturgeon Lake South Oilfield. The resource classification within the Sturgeon Lake South Oilfield is elevated to an indicated mineral resource due to 1) the correlation of historical Li-brine data in conjunction with 2021-2022 brine analytical work conducted by LithiumBank; 2) reinterpretation of 2-D seismic data and understanding of the dimensions of the Leduc Formation reef buildups; and 3) mineral processing test work – all of which have advanced the confidence level of the Li-brine concentration, geological model and potential for recovery of lithium from the brine. The inferred mineral resource area is defined by the remaining area of the Sturgeon Lake Reef Complex that is situated outside of the indicated mineral resource area.

Three-dimensional wireframes of the Leduc Formation aquifer were created using the grid surfaces of the top and base of the Leduc Formation within the 3-D geological model. The 2-D strings were connected to create a solid 3-D wireframe of the Leduc Formation aquifer within the resource areas. Only those parts of the Sturgeon Lake Reef Complex that occur within the permitted LithiumBank Boardwalk Property were used in the resource estimate process. The 3-D closed solid polygon wireframe of the Leduc Formation aquifer domain was used to calculate the volumes of rock, or the aquifer volumes. The aquifer volumes underlying the Boardwalk Property, summarized as the total Leduc Formation domain aquifer volumes, are 19.94 km^3 and 305.00 km^3 in the indicated and inferred resource areas, respectively.

The brine volumes are calculated for the Leduc Formation aquifer domain, or resource areas, by multiplying the aquifer volume (in km^3) times the average porosity times the percentage of brine assumed within the pore space. Using an average effective porosity value of 5.3% and an average modal abundance of brine in the Leduc Formation pore space percentage of 98%, the indicated and inferred resource brine volumes are 1.04 km^3 and 15.84 km^3, respectively.

Average Leduc Formation aquifer brine lithium concentrations of 71.6 milligrams per liter (mg/L) Li and 68.0 mg/L Li were selected for the calculation of the indicated and inferred resource estimations. These values were determined from a lithium assay database of 25 ICP-OES analyses conducted by LithiumBank's primary lab (indicated resource area) and 89 LithiumBank and historical ICP-OES analyses (inferred resource area). The quality of the average lithium concentrations was assessed and is considered to represent high levels of analytical precision.

The Li-brine resources were estimated using a cut-off grade of 50 mg/L lithium. With respect to units of measurement, 1 mg/L = 1 g/m^3. If concentration is in mg/L and volume in m^3, then the calculated resource has units of grams. (1 g/m^3 x 1 m^3 = 1 gram or 0.001 kg).

The Boardwalk Leduc Formation Li-brine indicated resource estimate is globally estimated at 74,000 tonnes of elemental Li (Table 1-1). The global (total) lithium carbonate equivalent for the main resource is 395,000 tonnes.

The Boardwalk Leduc Formation Li-brine inferred resource estimate is globally estimated at 1,077,000 tonnes of elemental Li (Table 1-2). The global (total) lithium carbonate equivalent for the main resource is 5,734,000 tonnes.

Mineral resources are not mineral reserves and do not have demonstrated economic viability. There is no guarantee that all or any part of the mineral resource will be converted into a mineral reserve. The estimate of mineral resources may be materially affected by geology, environment, permitting, legal, title, taxation, socio-political, marketing, or other relevant issues.

Table 1-1: Boardwalk indicated Li—brine resource estimation presented as a global (total) resource that is contained within the Leduc Formation of the Sturgeon Lake South Oilfield

	Reporting parameter	Leduc Formation Reef Domain
Indicated Resource Estimate	Aquifer volume (km^3)	19.942
	Brine volume (km^3)	1.036
	Average lithium concentration (mg/L)	71.6
	Average porosity (%)	5.3
	Average brine in pore space (%)	98.0
	Total elemental Li resource (tonnes)	74,000
	Total LCE (tonnes)	395,000

Note 1: Mineral resources are not mineral reserves and do not have demonstrated economic viability.
Note 2: The weights are reported in metric tonnes (1,000 kg or 2,204.6 lbs).
Note 3: Tonnage numbers are rounded to the nearest 1,000 unit.
Note 4: In a 'confined' aquifer (as reported herein), porosity is a proxy for specific yield.
Note 5: The resource estimation was completed and reported using a cutoff of 50 mg/L Li.

Note 6: To describe the resource in terms of industry standard, a conversion factor of 5.323 is used to convert elemental Li to Li_2CO_3, or Lithium Carbonate Equivalent (LCE).

Table 1-2: Boardwalk inferred Li—brine resource estimation presented as a global (total) resource that is contained within the Leduc Formation that encompasses the Sturgeon Lake Reef Complex outside of the Sturgeon Lake South Oilfield (or area of the indicated mineral resource)

	Reporting parameter	Leduc Formation Reef Domain
Inferred Resource Estimate	Aquifer volume (km^3)	304.999
	Brine volume (km^3)	15.842
	Average lithium concentration (mg/L)	68.0
	Average porosity (%)	5.3
	Average brine in pore space (%)	98.0
	Total elemental Li resource (tonnes)	1,077,000
	Total LCE (tonnes)	5,734,000

Note 1: Mineral resources are not mineral reserves and do not have demonstrated economic viability.

Note 2: The weights are reported in metric tonnes (1,000 kg or 2,204.6 lbs).

Note 3: Tonnage numbers are rounded to the nearest 1,000 unit.

Note 4: In a 'confined' aquifer (as reported herein), porosity is a proxy for specific yield.

Note 5: The resource estimation was completed and reported using a cutoff of 50 mg/L Li.

Note 6: To describe the resource in terms of industry standard, a conversion factor of 5.323 is used to convert elemental Li to Li_2CO_3, or Lithium Carbonate Equivalent (LCE).

1.4 Mining Methods

The Mining Methods section of this report describes the method of lithium resource production. The source of lithium is from the brine water contained within the Leduc Formation as an in-situ resource. The production method is not with surface mining but instead using deep vertical or deviated wells which produce the lithium rich brine which is then pipelined to the Central Processing Facility (CPF). The project is targeting a total lithium brine production rate of 250,000 m^3/d over a period of 20 years from 50 production wells. This production rate is the basis for the numerical modeling and well network design.

The depleted lithium brine is returned to the Leduc Formation through injection wells. The well network design is based on 50 injection wells, which are spaced a distance from the production wells to optimize reservoir pressure and mitigate early breakthrough of depleted lithium brine. The total lithium depleted brine is 255,404 m^3/d, which includes additional water from the process, which is expected to be sufficiently accommodated by the Leduc Formation without exceeding the maximum wellhead pressure.

The well network utilizes multi-well surface pads to minimize surface footprint. Up to 23 multi-well pads are planned for this project. The wells are drilled from these pads, starting vertically at surface, and deviating in the subsurface to achieve the desired bottomhole target for each well. The well program is expected to take up to two years for drilling utilizing three drilling rigs. The production wells require artificial lift to produce the large brine volumes to surface, which is achieved utilizing Electrical Submersible Pumps (ESP).

1.5 Recovery Methods

1.5.1 Lithium Extraction

LithiumBank commissioned the test work program to establish the selective lithium extraction performance of Go2Lithium's Direct Lithium Extraction (DLE) technology, and to develop an understanding of the process conditions to generate lithium concentrates that are suitable for battery grade lithium products. The first stage of the work was completed at Go2Lithium's lab facility, and entailed: bench scale tests to determine the equilibrium and kinetic properties of the DLE sorbent for loading and elution; and tests demonstrating the applicability of continuous ion exchange using counter-current mixed contactors to maximize the extraction and elution efficiency. The DLE sorbent utilized in this test program demonstrated the capability to selectively extract lithium from LithiumBank's feed brine and produce a lithium concentrate suitable for downstream production of lithium chemicals. The lithium recovery from DLE testwork was over 98%.

1.5.2 Lithium Plant

The lithium processing facility is designed for a nameplate production of approximately 34,299 tonnes per annum of battery grade lithium hydroxide monohydrate (30,210 metric tonnes per annum LCE) processing a feed brine throughput of 250,000 m^3/d at an average concentration of 70.1 mg/L. The operating factor considered in the process is 90%. The overall lithium recovery is estimated to be approximately 98%, considering the high DLE circuit recovery as specified by Go2Lithium.

Subsequent to the removal of the dissolved H_2S, the residual suspended solids and the hydrocarbon in the brine, lithium is preferentially extracted through Go2Lithium's DLE ion exchange technology. After removal of the precipitated impurities from the eluate, the lithium concentrate is polished prior to the lithium sulfate electrochemical process to produce lithium hydroxide. Battery grade lithium hydroxide monohydrates are produced through two stages of crystallization, followed by drying and packaging.

1.6 Environmental

Environmental aspects described in Section 20 include discussion of:

- Environmental permitting and regulatory requirements.
- Potential environmental baseline studies.
- Potential environmental issues and considerations, including environmental management plans and monitoring requirements.
- Anticipated remediation and reclamation activities.

- Social and community impacts.

It is understood that the Alberta Energy Regulator (AER) would be the primary lifecycle regulator of the entire project. As such, *Directive 090 – Brine Hosted Mineral Resource Development* of the AER will be the primary applicable directive. In addition to *Directive 090,* there are several supplementary directives provided by the AER that would apply to the Boardwalk project. A significant consideration is the potential requirement for a Provincial Environmental Impact Assessment, which would require extensive baseline studies and assessment, as well as formalized engagement with local communities, relevant stakeholders, and indigenous groups (in addition to the consultation programs that are reportedly ongoing).

Following closure operations at the Boardwalk facility, monitoring and reclamation requirements will need to be conducted, including decommissioning of onsite facilities associated with the project, remediating environmental media contaminated as a result of project operations and restoring land that was utilized for project activities.

Future advancement of the Boardwalk project is recommended to include the ongoing development, refinement, and implementation of a community engagement plan including Indigenous Groups and community stakeholders. Additionally, an initial liaison with provincial agencies and the Alberta Energy Regulator, should be conducted to determine the basis upon which the decision to require an EIA will be made. This will also provide LithiumBank an opportunity to ensure that the AER is aware of work conducted to assess environmental impacts and address community/First Nations concerns to date. Upon completing this, the overall scope and timeline of required environmental studies can be determined.

1.7 Capital and Operating Cost Estimates

The Capital Expenditure (CAPEX) Estimate was prepared consistent to an Association for the Advancement of Cost Engineering (AACE) Class 5 Study, with an approximate accuracy of +50%, -30%.

The total estimated CAPEX for the project is presented in the table below, inclusive of contingency.

Table 1-3: Capital Cost Estimate Summary

WBS Level 1	WBS Level 1 Name	Estimated Cost (M USD)
0000	Plant Wide - General	$ 26.7
1000	Onsite Infrastructure	$ 265.2
2000	Offsite Infrastructure	$ 19.5
3000	Brine Wellfield Services	$ 273.0
4000	Surface Brine Infrastructure	$ 207.6
5000	Lithium Processing Plant	$ 610.7

WBS Level 1	WBS Level 1 Name	Estimated Cost (M USD)
Direct Cost - Subtotal		$ 1,402.7
Indirect Cost		$ 327.3
Contingency		$ 373.5
Owner's Cost		$ 56.1
Total Project Capital Cost		$ 2,159.7

The Operating Expenditure (OPEX) Estimate for the project was also prepared consistent to an AACE Class 5 Study. The total OPEX is presented below.

Table 1-4: Operating Cost Summary

Cost Component	Lithium Plant Annual Operating Cost (M USD)	Lithium Plant Unit Operating Cost (USD/t LHM)	% of total OPEX
Reagents	37.3	1,089	24%
Utilities	51.9	1,515	33%
Consumables	16.5	482	11%
Labour	17.6	513	11%
Maintenance Materials and Services	18.7	546	12%
Transport and Logistics	6.6	192	4%
General and Administrative (G&A)	6.7	196	4%
Total Operating Cost	155.2	4,533	100%

1.8 Economic Analysis

The PEA is preliminary in nature. It includes inferred mineral resources that are too speculative geologically to have 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.

The base case assumes a long-term lithium hydroxide monohydrate (LHM) price of US$26,000/t. At this price the project achieves a positive NPV at an 8% real discount rate. A summary of key indicators is shown in Table 1-5.

Table 1-5: Key Indicators Summary

Item	Unit	Value
LHM Sales	t/year	34,005
LHM Price	US$/t	26,000
Site Operating Unit Cost	US$/t sold	4,588
Site Operating Cost	US$M/year	154
EBITDA	US$M/year	715
Project Life	years	20

Item	Unit	Value
Initial Capital Cost	US$M	2,160
Sustaining Capital Cost	US$M	131
USD/CAD Exchange Rate	US$/C$	0.73
Pre-tax NPV @ 8%	US$M	3,679
After-tax NPV @ 8%	US$M	2,305
Pre-tax IRR	%	25.0%
After-tax IRR	%	20.6%
Pre-tax Payback	operating years	3.5
After-tax Payback	operating years	3.9

Returns are sensitive to input assumptions and should be viewed in the context of the sensitivity analysis provided in this section as well as the stated accuracies for items such as capital costs.

The reader is cautioned that the 98% lithium recovery used in this analysis has not yet been proven at commercial scale (see Section 25.6.4 Recovery Methods Risks). As such, the sensitivity around recovery is particularly important. In general, each 1% absolute drop in recovery decreases modeled pre-tax and after-tax NPV by US$62M and US$42M, respectively, and decreases pre-tax and after-tax IRR by 0.24% and 0.20%, respectively.

1.9 Interpretation and Conclusions

1.9.1 Exploration and Resource Estimation

The QP has reviewed the adequacy of the geochemical, stratigraphic, hydrogeological, and mineral processing information discussed in this Technical Report and found no significant issues or inconsistencies that would cause one to question the validity of the data. The QP is satisfied to include the exploration data within the resource modeling, evaluation and estimations as presented in this report.

The Li-brine indicated and inferred resource estimations within the Leduc Formation aquifer underlying the Boardwalk Property are predicted to contain 74,000 tonnes indicated elemental lithium (at 71.6 mg/L Li) and 1,077,000 tonnes of inferred elemental lithium (at 68.0 mg/L Li). This corresponds to 395,000 tonnes of indicated LCE and 5,734,000 tonnes of inferred LCE resources.

Mineral resources are not mineral reserves and do not have demonstrated economic viability. There is no guarantee that all or any part of the mineral resource will be converted into a mineral reserve.

The Li-brine resource estimations presented in this technical report are subject to change as the project achieves higher levels of confidence in the spatial extent of the aquifers, mineralization, metals-from-brine recovery processes, DLE technological development, and utilization of the appropriate cutoff value in relation to extraction results.

Risks and uncertainties include 1) the well status of most of the Devonian producing wells in the Sturgeon Lake oilfield are in a suspended state (as dictated by the Petro-companies); hence any additional brine sampling/testing programs would require additional costs and an agreement between LithiumBank and the Petro-company, and 2) the Direct Lithium Extraction technology is in the development stage and has not yet been proven at the commercial scale.

1.9.2 Well Network

The subsurface recovery method for lithium extraction utilizes deep wells to produce the lithium enriched brine and reinject the depleted brine from the Leduc formation. The well network includes 50 production wells and 50 reinjection wells for depleted brine, for a total of 100 wells which are located on 23 multi-well surface pads.

The well design is based on proven technologies and practices from the oil and gas industry. The drilling of the 100 wells is expected to take two years with the use of three drilling rigs. This includes the construction of the surface pads and road access, drilling, casing, and completion of the wells.

1.9.3 Recovery Methods

1.9.3.1 Lithium Extraction

A test work program was carried out to define the process parameters for Go2Lithium’s DLE technology.

The QP for the lithium extraction process concludes that the adopted DLE technology in this technical report has sufficiently demonstrated at the laboratory bench scale that the technology may be used to selectively extract lithium from the brine to generate a concentrated lithium stream for further lithium processing.

1.9.3.2 Lithium Plant

A series of steps are designed in the lithium extraction process to produce battery grade lithium hydroxide monohydrate from the brine. The main processing steps include H_2S mitigation, TSS/TOC removal steps, DLE, concentration, purification, lithium sulfate electrochemical process, and lithium hydroxide monohydrate conversion. The battery grade lithium hydroxide monohydrate crystals are then dried and packaged for short-term storage prior to shipment to customers.

1.9.4 Economics

The PEA base case generates a sufficiently positive after-tax NPV and IRR to support continuation to the next stage of project development activities.

1.9.5 Risks, Opportunities, Uncertainties

Several opportunities and risks were identified during the preparation of the PEA. It is recommended that these be investigated further in a subsequent Pre-Feasibility Study (PFS) Phase. Additional, larger-scale pilot test work is required to demonstrate the process and to evaluate opportunities to mitigate technical risks, and improve capital and operating costs, using the pilot plant facility constructed by Go2Lithium.

1.10 Recommendations

The main next steps and work recommendations for LithiumBank's Boardwalk Property:

1.10.1 Exploration

LithiumBank's Boardwalk Property is a property of merit. With respect to exploration work recommendations, a program estimated to cost approximately CDN$8.8 million with 10% contingency is designed to include:

- The acquisition of a minimum of three existing wells with associated infrastructure to ensure continual brine access for experimental test work.
- The collection of additional Leduc Formation aquifer brine samples (and possibly brine from deeper stratigraphic aquifers) should be collected for further assaying to refine and add confidence to the Boardwalk Property Leduc Formation lithium values.
- Downhole geological, geophysical, and hydrogeological studies intended to provide added confidence in the understanding of the geological and hydrogeological conditions within the Leduc Formation reservoir.
- Lastly, LithiumBank should continue assess and disclose material matters through technical reporting in accordance with CIM definition standards and best practice guidelines (2014, 2019) and the disclosure rule NI 43-101.

1.10.2 Well Network

- Complete a minimum of three well tests with at least one new well being drilled in the main part of the development area to gather information such as core samples across the Leduc formation, fluid samples from the Leduc brine to confirm water/gas composition and fluid compatibilities; flow and injectivity tests including pressure analysis; and a core analysis for particle size distribution for completion design, etc.
- Work with vendors and technology developers to find a smaller diameter ESP which could allow for smaller diameter wellbores; investigate re-use or well extensions from existing oil and gas wells that have good well integrity; investigate drilling options that manage the supply chain and service contracts to lower well drilling costs; and evaluate if less multi-well pads could be used which requires extended deviated wells.

1.10.3 Lithium Extraction and Process

1.10.3.1 Lithium Extraction

- Confirmative test work at a larger scale on sorbent performance.
- Further bench scale test work to assess the longevity of the DLE sorbent to further define the sorbent replacement frequency.

- Pilot testing on the DLE loading/elution cycles to validate and optimize the process conditions, and potentially improve the DLE performance.
- Undertake a sensitivity analysis on the impact that sorbent residence time in adsorption has on plant size and sorbent inventory.

1.10.3.2 Lithium Plant

- Pilot test on the feasibility of the lithium sulfate electrochemical process.
- Tradeoff studies to compare the process flowsheets to produce battery grade lithium carbonates and lithium hydroxide monohydrate.
- Water optimization trade-off.
- Prioritizing and selecting the favored options from the tradeoff studies to update the process flowsheet.
- Assessment of the project’s viability to proceed to the feasibility study phase.

2. Introduction

2.1 Issuer and Purpose

This Technical Report has been prepared for the Issuer, LithiumBank Resources Corp. (LithiumBank or the Company). LithiumBank has acquired 100% minerals interest in four separate lithium-brine (Li-brine) properties in west-central Alberta: Boardwalk, Park Place, Simonette, and Peace Area. Collectively, the properties comprise 110 combined Rock-Hosted Mineral Permits and Brine-Hosted Mineral Licences that encompass 760,346 hectares (ha). LithiumBank acquired the properties to explore for Li-brine.

This Technical Report focuses on LithiumBank's flagship property, the Boardwalk Property, which is in west-central Alberta, directly south and west of the Town of Valleyview and 270 km northwest of the City of Edmonton (Figure 2.1). The Boardwalk Property is comprised of 26 combined Rock-Hosted Mineral Permits and Brine-Hosted Mineral Licences (permits/licences) that collectively form a contiguous package of land that totals 170,424 ha for which LithiumBank has 100% ownership of the mineral rights.

At the Boardwalk Property, LithiumBank is assessing Late Devonian aquifers associated with carbonate buildups in the Leduc Formation of the Woodbend Group for their Li-brine potential. Access to the deep-seated confined aquifer Li-brine at the Boardwalk Property has historically been from oil and gas wells that have pumped the brine from depths of more than 2,350 m to the earth's surface – essentially as wastewater associated with hydrocarbon products. However, and as detailed in this preliminary economic scoping study, LithiumBank is considering the potential of operating the Company's own well(s) as part of a standalone Direct Lithium Extraction opportunity to recover lithium from the Leduc Formation aquifer brine.

During 2021, LithiumBank formed an access agreement with the Petro-operator to reopen suspended oil and gas wells to obtain brine from the Leduc Formation aquifer underlying the Sturgeon Lake South Oilfield portion of the Property. The acquisition of brine has allowed LithiumBank to verify the historical brine assays and conduct mineral processing test work to extract the lithium from the brine. Previously, LithiumBank disclosed an initial inferred mineral resource at the Boardwalk Property (then the Sturgeon Lake Property) with an Effective Date of 18 May 2021, followed by an updated indicated and inferred Boardwalk Li-brine resource estimates with an Effective Date of 20 December 2022. This updated Preliminary Economic Assessment scoping study, which now represents LithiumBank's current technical report, includes revised indicated and inferred mineral resources due to a recent change in the outline of LithiumBank's Boardwalk Property contiguous permits/licences (see Section 4).

The Technical Report is prepared in accordance Canadian Institute of Mining, Metallurgy and Petroleum definition standards and best practice guidelines (CIM 2014, 2019) and the Canadian Securities Administration's (CSA) Standards for Disclosure of Mineral Projects, National Instrument 43-101 (NI 43-101). The effective date of this report is 22 February 2024, and the report supersedes and replaces all previous Technical Reports.

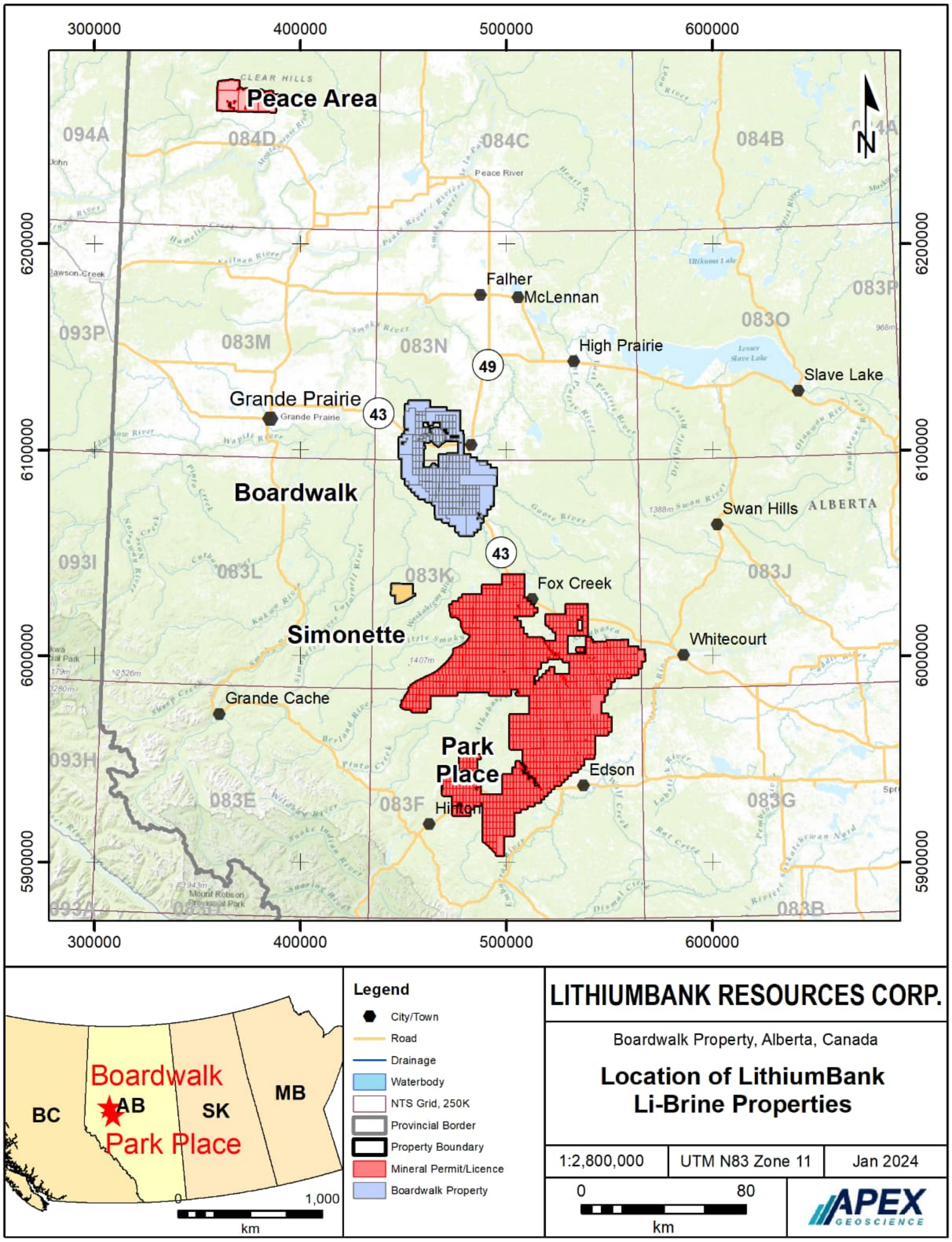


Figure 2.1: General location of LithiumBank's Alberta Li-brine properties. This Technical Report focuses on the Boardwalk Property

2.2 Authors and Site Inspection

2.2.1 Authors

A multi-disciplinary team of authors prepared this report and include R. Eccles M.Sc. P. Geol. of APEX Geoscience Ltd., J. Touw, B.Sc., P. Geol. of Hydrogeological Consultants Ltd., K. Moher of GLJ Ltd., G. MacMillian of Fluid Domains, F. Scott of Scott Energy Inc., S. Hlouschko of Hatch Ltd., E. Jones of Hatch Ltd., and E. Linton of Hatch Ltd. The authors are independent of LithiumBank Resources Corp., the Boardwalk Property, and are Qualified Persons (QPs) as defined in NI 43-101.

A list of the QPs responsible for each section of this report is provided in the below table, and their QP certificates are appended to the back of this report.

Table 2-1: QPs of the PEA Report

Report Chapter	Qualified Person	Company
Section 1: Summary	Various QPs	Various
Section 2: Introduction	Various QPs	Various
Section 3: Reliance on Other Experts	Various QPs	Various
Section 4: Property Description and Location	R. Eccles	APEX Geoscience Ltd.
Section 5: Accessibility, Climate, Local Resources, Infrastructure, and Physiography	R. Eccles	APEX Geoscience Ltd.
Section 6: History	R. Eccles	APEX Geoscience Ltd.
Section 7: Geological Setting and Mineralization	R. Eccles	APEX Geoscience Ltd.
Section 8: Deposit Types	R. Eccles	APEX Geoscience Ltd.
Section 9: Exploration	R. Eccles	APEX Geoscience Ltd.
Section 10: Drilling	R. Eccles	APEX Geoscience Ltd.
Section 11: Sample Preparation, Analyses and Security	R. Eccles	APEX Geoscience Ltd.
Section 12: Data Verification	R. Eccles	APEX Geoscience Ltd.
Section 13: Mineral Processing and Metallurgical Testing	L. Park	Process Engineering Options
Section 14.1, 0, 14.4-14.12: Mineral Resource Estimates	R. Eccles	APEX Geoscience Ltd.
Section 14.3: Mineral Resource Estimates	J. Touw	Hydrogeological Consultants Ltd.
Section 0: Mineral Reserve Estimates	-	-
Section 16.1-16.4: Mining Methods	G. MacMillan	Fluid Domains
Section 16.5-16.11: Mining Methods	K. Moher	GLJ Ltd.
Section 16.12: Mining Methods	G. MacMillan	Fluid Domains
Section 17.1-17.2.2, 17.2.4-17.3: Recovery Methods	E. Linton	Hatch Ltd.
Section 17.2.3: Recovery Methods	L. Park	Process Engineering Options

Report Chapter	Qualified Person	Company
Section 18.1-18.4: Project Infrastructure	E. Linton	Hatch Ltd.
Section 18.5-18.6: Project Infrastructure	F. Scott	Scott Energy Inc.
Section 19: Market Studies and Contracts	S. Hlouschko	Hatch Ltd.
Section 20: Environmental Studies, Permitting and Social or Community Impact	E. Jones	Hatch Ltd.
Section 21.1.1, 21.1.2.1, 21.1.2.3, 21.1.2.5-21.1.2.6, 21.1.3-21.1.6, 21.2, 21.4-21.4.6, 21.4.7.2-21.4.10: Capital and Operating Costs	E. Linton	Hatch Ltd.
Section 21.3: Capital and Operating Costs	E. Jones	Hatch Ltd.
Section 21.1.2.4, 21.4.7.1: Capital and Operating Costs	K. Moher	GLJ Ltd.
Section 21.1.2.2: Capital and Operating Costs	F. Scott	Scott Energy Inc.
Section 22: Economic Analysis	S. Hlouschko	Hatch Ltd.
Section 23: Adjacent Properties	R. Eccles	APEX Geoscience Ltd.
Section 24: Other Relevant Data and Information	E. Linton	Hatch Ltd.
Section 25: Interpretation and Conclusions	All QPs	Various
Section 26: Recommendations	All QPs	Various
Section 27: References	All QPs	Various

2.2.2 Personal Inspection of Property by Qualified Persons

Mr. Eccles last visited the Boardwalk Property on July 27-29, 2021, as part of a NI 43-101 site inspection. The inspection enabled the QP to 1) confirm LithiumBank's Boardwalk Property land holdings 2) observe the reopening of suspended oil and gas wells that produced hydrocarbons (and brine) from the Leduc Formation reservoir underlying the Property, and 3) independently sample Leduc Formation brine and validate the Li-brine mineralization that is the subject of this technical report.

2.3 Sources of Information

The Report is based upon information and data collected by LithiumBank, and data collected, compiled, and validated by the authors. The information contained within the Report was derived from the following:

- Technical reports and maps, laboratory analysis, third-party reports, and field sample data.
- Estimates and quotes provided by third parties.
- Test work results on the brine samples and Direct Lithium Extraction process.
    - Brine geochemical results include Alberta government compilations and analytical results that were conducted by exploration companies at commercial, accredited laboratories such as Bureau Veritas Laboratories (Bureau Veritas) in Edmonton, AB,

AGAT Laboratories (AGAT) in Calgary and Edmonton, AB, and the Saskatchewan Research Council (SRC) in Saskatoon, SK.

- Industry data software such as AbaData (Abacus Datagraphics), geoSCOUT (geoLOGIC Systems Ltd.), and Accumap (HIS Markit)
- Publicly available literature, including Government reports and Journal articles as listed in Section 27. In-text references are included throughout the report, where relevant.

The Qualified Person reviewed the Alberta Energy Metallic and Industrial Mineral Disposition of Mineral Rights data (https://gis.energy.gov.ab.ca/Geoview/Metallic), which showed that LithiumBank's Boardwalk mineral permits are active and in good standing as of January 13, 2024. The mineral permits are currently being converted to Rock-Hosted Mineral Permits and Brine-Hosted Brine Licences by the Government of Alberta.

For the information utilized in the report, the QP has deemed that these reports and information, to the best of their knowledge, are valid contributions.

2.4 Units of Measure and Terms of Reference

With respect to units of measure, unless otherwise stated, this Technical Report uses:

- Abbreviated shorthand consistent with the International System of Units (International Bureau of Weights and Measures, 2006).
- 'Bulk' weight is presented metric tonnes (tonnes; 1,000 kg or 2,204.6 lbs).
- Geographic coordinates are projected in the Universal Transverse Mercator (UTM) system relative to Zone 11 of the North American Datum (NAD) 1983.
- Currency in US dollars (USD), unless otherwise specified.
- Abbreviations used throughout this report are outlined below in Table 2-2.

Table 2-2: List of Abbreviations

Abbreviation	Description
AB	Alberta
AER	Alberta Energy Regulator
AEP	Alberta Environment and Parks
AGAT	AGAT Laboratories
AMGAS	AMGAS Services Inc.
Br	Bromine
BTEX	benzene, toluene, ethylbenzene, and xylene
BV	Bureau Veritas
CAM	Cathode active material
CNRL	Canadian Natural Resources Ltd.
CNWA	Canada Navigable Wasters Act

Abbreviation	Description
CPF	Central Processing Facility
DFO	Fisheries and Oceans Canada
DLE	Direct Lithium Extraction
DST	Drill stem test
EDC	Environmental Design Criteria
EIA	Environmental Impact Assessment
EMP	Environmental Management Plans
EPEA	Environmental Protection and Enhancement Act
ESA	Environmental Site Assessment
ESP	Electrical submersible pump
ESS	Energy storage systems
EV	Electric vehicle
g/cm^3	grams per cubic centimeter
HCL	Hydrogeological Consultants Ltd.
HEPH	Heavy Extractable Petroleum Hydrocarbons
H_2S	Hydrogen sulfide
ICP-OES	Inductively-Coupled Plasma – Optical Emission Spectroscopy
IPR	Inflow performance curve
IX	Ion Exchange
LCE	Lithium carbonate equivalent
LEPH	Light Extractable Petroleum Hydrocarbons
Li	Lithium
Li_2CO_3	Lithium Carbonate
LEXG	Lithium Exploration Group
LFP	Lithium Iron Phosphate
LHM	Lithium hydroxide monohydrate
K	Potassium
km	kilometer
km^2	square kilometers
m	meter
m^3	cubic meters
m asl	meters above sea level
mD	millidarcies
MD	measured depth
mg/L	milligrams per liter
MGX	MGX Minerals Inc.
MPP	Midpoint of perforations
MW	megawatts

Abbreviation	Description
NGTL	NOVA Gas Transmission Ltd
NSF	Nutshell filtration
PAH	Polycyclic Aromatic Hydrocarbons
PEA	Preliminary economic assessment
pCAM	Precursor cathode active materials
PRA	Peace River Arch
ppm	parts per million
ppmv	parts per million by volume
QA	Quality Assurance
QC	Quality Control
RSD	relative standard deviation
Sr	Strontium
SRC	Saskatchewan Research Council
SLCN	Sturgeon Lake Cree Nation
TDS	Total Dissolved Solids
TDE	Thermodesign Engineering
TOC	Total Organic Carbon
TPH	Total petroleum hydrocarbon.
TSS	Total Suspended Solids
TVD	True vertical depth
µS/cm	Microsiemens per centimeter
VFD	Variable Frequency Drive
WCBS	Western Canada Sedimentary Basin
WHP	well head pressure

3. Reliance on Other Experts

Other experts and sources were relied upon for data, documents and/or verbal/written statements that was utilized in the preparation of this document, which may fundamentally and materially impact the outcomes of the PEA. The qualified persons who authored the sections in the Report believe that it is reasonable to rely on the below information and have taken reasonable measures to confirm information, but independent verification of the input data was not performed.

In addition to the reports and documents noted in Section 27, the following information was relied upon:

3.1 Hatch Ltd.

Hatch relied on information provided by the Owner and on behalf of the Owner by third parties, without independent verification. To mitigate the risk of errors and omissions in third party information, Hatch worked in accordance with good industry practice taking reasonable steps to confirm the accuracy and sufficiency of the information provided. This required Hatch to bring to the attention of the Owner any error or omission in the normal course of performing our review.

- Hatch relied on test work data produced and presented by Go2Lithium. The test work data was utilized to confirm key process parameters needed to define the lithium extraction process, which, in turn, was used to produce the mass and energy balances which forms the basis of all equipment duties. This information directly impacts Sections 13, 17, 21 and 22.
- Go2Lithium provided to Hatch information related to their lithium extraction technology, including sorbent replacement frequency as well as inputs to the capital and operating cost estimates. This information directly impacts Section 21.
- Hatch obtained reagent grades/compositions and pricing by identified suppliers to estimate reagent consumptions and costs. The majority of reagent pricing and composition was provided by Univar Solutions, provided by email on 31 October 2022. The pricing of sulfuric acid was provided by Chemtrade by email on 25 April 2023. Reagent pricing and composition directly impacts the process design, Section 21, and operating cost estimate, Section 21. Additionally, a Price Forecast for Caustic Soda was obtained. The price forecast in Western Canada was obtained on 10 February 2023 from ResourceWise.
- LithiumBank provided input to operating cost estimates, Section 21, mainly associated with employee salaries. Hatch reviewed the salaries alongside other inhouse data to ensure the salaries were within an appropriate range.
- Market reports published by Wood Mackenzie were utilized to establish current and projected lithium market conditions, for the purpose of the market assessment detailed in Section 19.

3.2 APEX Geoscience Ltd.

The author is not qualified to provide an opinion or comment on issues related to legal agreements, mineral titles, royalties, permitting and environmental matters. Accordingly, the author disclaims portions of this Technical Report in Sections 4.1 to 4.3, which relate to the legal status of the Property. More specifically, and because of Alberta's revised *Mines and Minerals Act*: Metallic and Industrial Minerals Tenure Regulation, the Province has yet to convert Alberta Metallic and Industrial Mineral Permits to the new tenure format, which includes Rock-Hosted Mineral Permits and Brine-Hosted Mineral Licences. The Qualified Person has validated LithiumBank's December 2023 notices to the Government of Alberta to allocate specific permits/licences to the new tenure format. Subject to payment of Brine-Hosted Mineral Licences fees by LithiumBank, the Qualified Person is not aware of any issues that would affect the successful transition of the permits/licences.

3.3 GLJ Ltd.

- GLJ relied upon the data provided by LithiumBank and Hatch to prepare Section 16, and provide inputs to Section 21, 24, and 25 related to the well network design. GLJ is not qualified to provide comments on any other content of the report.
- GLJ relied upon Gord MacMillan, P.Geol. of Fluid Domains, and Curtis Heller, P.Eng. of Frontier Project Solutions to provide support for the completion of Section 16 and the well network design.

3.4 Go2Lithium

- Go2Lithium executed a testwork program using a feed brine sample provided by LithiumBank and sorbent sourced by Go2Lithium. The outcomes of the testwork were interpreted by Go2Lithium and translated into process design criteria. This work is reported in Section 13 and Section 17.
- Using a design operating point specified by Hatch, Go2Lithium developed a preliminary equipment list and equipment sizing. Based on the operating point and sizing, Go2Lithium provided inputs to Section 21.
- All elemental analysis for the test work completed by Go2Lithium was carried out by HRL Technology Group Pty Ltd (located in Melbourne, Australia), a NATA-accredited laboratory under ISO/IEC 17025.

4. Property Description and Location

4.1 Notice of Recent Alberta Mineral Tenure Regulation Change

On January 1, 2023, the Government of Alberta revised the provinces *Mines and Minerals Act*: Metallic and Industrial Minerals Tenure Regulation (Alberta Regulation 265/2022). A major component of the revised tenure regulations was to redefine, or divide, Metallic and Industrial Minerals Permits and Leases into 1) Rock-Hosted Minerals Permits and Leases, and 2) Brine-Hosted Minerals Licences and Leases. The new brine-hosted designation was in specific response to the lithium-brine interest in Alberta (and other minerals of interest in the brine such as bromine, boron, magnesium, calcium, etc.).

As part of the tenure regulation revision, the Government of Alberta provided brine exploration companies, including LithiumBank, with the exclusive rights to apply for, and convert, previously granted mineral permits that are in good standing into Brine-Hosted Mineral Licences by December 31, 2023.

In December 2023, LithiumBank revised the Company's Alberta land position and instructed the Government of Alberta to convert the mineral permits into both Rock-Hosted Mineral Permits and Brine-Hosted Mineral Licences.

4.2 Introduction

LithiumBank has four separate Li-brine properties in west-central Alberta that include Boardwalk, Park Place, Simonette, and Peace Area. Collectively, the properties comprise 110 combined Rock-Hosted Mineral Permits and Brine-Hosted Mineral Licences that encompass 760,346 hectares (ha). The descriptions and outlines of the four properties are presented in Figure 4.1 and Figure 4.2.

This Technical Report focuses solely on the Boardwalk Property, which is highlighted in Figure 4.1 and Figure 4.2, and described in the text that follows.

4.3 Description and Location

The Boardwalk Property is comprised of 26 combined Host-Rock Mineral Permits and Brine-Hosted Mineral Licences (permits/licences) that collectively form a contiguous package of land that totals 170,424 ha (Figure 4.3). The permits/licences were acquired directly from the Government of Alberta through the Provinces on-line mineral tenure system and are 100% owned by LithiumBank. Because the 'original' mineral permits dated December 31, 2023, are undergoing a governmental transition to Rock-Hosted Mineral Permits and Brine-Hosted Mineral Licences due to Alberta's new mineral tenure regulations, a detailed illustration of LithiumBank's mineral tenure conversion is presented in Figure 4.4. At the Boardwalk Property, the 31 'original' mineral permits totaling 238,669 ha has been reduced to 26 Rock-Hosted Mineral Permits and Brine-Hosted Mineral Licences totaling 170,424 Ha (a reduction of 40%). The Brine-Hosted Mineral Licence term commencement date is not available at the Effective Date of this technical report because the Government of Alberta is in the process of converting permits/licences into the new mineral tenure regulation structure.

It's important to note that the Boardwalk Property reduction removed permit/licence areas that were located either directly adjacent to, or at the thin margins of, the Sturgeon Lake Reef Complex, which is the focus of the mineral resource estimation work presented in this technical report.

The Boardwalk Property is in west-central Alberta, directly south and west of the Town of Valleyview, approximately 85 km east of the City of Grande Prairie and 270 km northwest of the City of Edmonton (Figure 2.1). The Boardwalk Property is in the Municipal District of Greenview No. 16, the third largest municipal district in Alberta covering an area of 32,984 km^2. The municipal office is in Valleyview.

The Boardwalk Property encircles the Sturgeon Lake 154, and 154A First Nations Reserves and Young's Point Provincial Park (Figure 4.3). The Boardwalk Property is in 1:50 000 National Topographic System (NTS) map sheets: 83K/14, 83N/03 and 83N/04. The center of the Boardwalk Property is located at approximately 479,000 m Easting and 6,089,100 m Northing in Universal Transverse Mercator (UTM), Zone 11, North American Datum 1983 (NAD83).

Agreement Number	Status	Designated Representative	Ownership (%)	Term Date	Expiry date	Size MIMP To Dec. 31, 2023 (ha)	Size RHMP / BHML Currently being converted (ha)
A) Boardwalk							
9320070042	Active	2277445 Alberta Ltd.	100	2020-07-22	2034-07-22	9,216.00	6,885.01
9320070043	Active	2277445 Alberta Ltd.	100	2020-07-22	2034-07-22	9,216.00	9,216.00
9320070044	Active	2277445 Alberta Ltd.	100	2020-07-22	2034-07-22	8,148.60	8,148.60
9320070045	Active	2277445 Alberta Ltd.	100	2020-07-22	2034-07-22	6,518.70	6,518.70
9320070047	Active	2277445 Alberta Ltd.	100	2020-07-22	2034-07-22	9,088.00	9,088.00
9320070048	Active	2277445 Alberta Ltd.	100	2020-07-22	2034-07-22	9,216.00	9,216.00
9320070049	Active	2277445 Alberta Ltd.	100	2020-07-22	2034-07-22	9,216.00	8,439.00
9320070050	Active	2277445 Alberta Ltd.	100	2020-07-22	2034-07-22	9,216.00	9,216.00
9320070051	Active	2277445 Alberta Ltd.	100	2020-07-22	2034-07-22	9,216.00	9,216.00
9320110073	Active	2277445 Alberta Ltd.	100	2020-11-09	2034-11-09	9,216.00	9,216.00
9320110074	Active	2277445 Alberta Ltd.	100	2020-11-09	2034-11-09	9,042.18	9,042.18
9320110075	Active	2277445 Alberta Ltd.	100	2020-11-09	2034-11-09	8,252.76	8,252.76
9321010123	Active	2277445 Alberta Ltd.	100	2021-01-26	2035-01-26	9,216.00	/
9321010124	Active	2277445 Alberta Ltd.	100	2021-01-26	2035-01-26	4,053.60	/
9321060158	Active	2277445 Alberta Ltd.	100	2021-02-18	2035-06-25	1,024.00	/
9321070164	Active	2277445 Alberta Ltd.	100	2021-02-10	2035-07-09	6,144.00	/
9321070165	Active	2277445 Alberta Ltd.	100	2021-02-10	2035-07-09	8,704.00	4,560.02
9321070166	Active	2277445 Alberta Ltd.	100	2021-02-10	2035-07-09	9,216.00	/
9321070167	Active	2277445 Alberta Ltd.	100	2021-02-10	2035-07-09	9,216.00	4,036.02
9321070168	Active	2277445 Alberta Ltd.	100	2021-02-10	2035-07-09	9,216.00	7,921.01
9321070223	Active	2277445 Alberta Ltd.	100	2021-04-28	2035-07-16	8,690.20	5,323.21
9321070224	Active	2277445 Alberta Ltd.	100	2021-04-28	2035-07-16	8,960.00	6,111.01
9321070225	Active	2277445 Alberta Ltd.	100	2021-04-28	2035-07-16	8,889.90	7,853.90
9321070226	Active	2277445 Alberta Ltd.	100	2021-04-28	2035-07-16	8,832.00	5,465.01
9321070227	Active	2277445 Alberta Ltd.	100	2021-04-28	2035-07-16	9,216.00	5,590.01
9321070228	Active	2277445 Alberta Ltd.	100	2021-04-28	2035-07-16	7,168.00	1,470.02
9321070229	Active	2277445 Alberta Ltd.	100	2021-04-28	2035-07-16	9,216.00	4,295.02
9321090126	Active	2277445 Alberta Ltd.	100	2021-09-29	2035-09-29	324.23	324.23
9321090127	Active	2277445 Alberta Ltd.	100	2021-04-28	2035-09-29	5,740.36	5,740.36
9322060198	Active	2277445 Alberta Ltd.	100	2022-06-07	2036-06-07	64.00	64.00
9321110061	Active	2277445 Alberta Ltd.	100	2021-11-18	2035-11-18	9,216.00	9,216.00
Total permits: 31 to Dec. 31, 2023 (26 in conversion)					**Total area**	**238,668.53**	**170,424.08**
B) Peace Area							
9322040107	Active	2277445 Alberta Ltd.	100	2022-04-08	2036-04-08	8,580.00	8,580.00
9322040108	Active	2277445 Alberta Ltd.	100	2022-04-08	2036-04-08	8,500.00	8,500.00
9322040109	Active	2277445 Alberta Ltd.	100	2022-04-08	2036-04-08	8,320.00	8,320.00
9322040110	Active	2277445 Alberta Ltd.	100	2022-04-08	2036-04-08	4,099.87	4,099.87
Total permits	**4**				**Total area**	**29,499.87**	**29,499.87**
C) Simonette							
9322110203	Active	2277445 Alberta Ltd.	100	2022-11-24	2036-11-24	6,648.35	6,648.35
Total permits	**1**				**Total area**	**6,648.35**	**6,648.35**
D) Park Place							
9319060168	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	9,216.00	9,216.00
9319060169	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	9,192.00	9,192.00
9319060170	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	6,548.50	4,735.51
9319060171	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	9,180.40	9,180.40
9319060172	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	9,216.00	8,698.00
9319060173	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	9,216.00	5,072.02
9319060174	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	9,216.00	9,216.00
9319060175	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	9,216.00	9,216.00
9319060176	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	9,180.00	7,885.01
9319060177	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	7,680.00	7,162.00
9319060178	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	8,702.20	/
9319060179	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	8,753.60	6,940.61
9319060180	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	8,185.00	8,185.00
9319060181	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	9,177.10	9,177.10
9319060182	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	8,636.90	8,636.90
9319060183	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	9,216.00	3,000.02
9319060184	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	8,046.40	8,046.40
9319060185	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	9,216.00	9,216.00
9319060186	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	9,216.00	9,216.00
D) Park Place, continued							
9319060187	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	9,204.10	9,204.10
9319060188	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	8,714.90	7,937.90
9319060189	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	8,493.30	8,493.30
9319060190	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	4,608.00	4,608.00
9319060191	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	6,848.00	6,848.00
9319060192	Active	2277445 Alberta Ltd.	100	2019-06-21	2033-06-21	7,871.30	7,871.30
9319060200	Active	2277445 Alberta Ltd.	100	2019-06-28	2033-06-28	9,216.00	9,216.00
9319060201	Active	2277445 Alberta Ltd.	100	2019-06-28	2033-06-28	9,216.00	1,964.03
9319060202	Active	2277445 Alberta Ltd.	100	2019-06-28	2033-06-28	9,216.00	9,216.00
9319060203	Active	2277445 Alberta Ltd.	100	2019-06-28	2033-06-28	9,198.70	9,198.70
9319060204	Active	2277445 Alberta Ltd.	100	2019-06-28	2033-06-28	9,216.00	4,554.02
9319060205	Active	2277445 Alberta Ltd.	100	2019-06-28	2033-06-28	9,168.00	9,168.00
9319060206	Active	2277445 Alberta Ltd.	100	2019-06-28	2033-06-28	8,896.00	8,896.00
9319060207	Active	2277445 Alberta Ltd.	100	2019-06-28	2033-06-28	9,024.00	9,024.00
9319060208	Active	2277445 Alberta Ltd.	100	2019-06-28	2033-06-28	8,896.00	8,378.00
9319060209	Active	2277445 Alberta Ltd.	100	2019-06-28	2033-06-28	9,216.00	7,921.01
9320010138	Active	2277445 Alberta Ltd.	100	2020-01-14	2034-01-14	9,189.10	9,189.10
9320010139	Active	2277445 Alberta Ltd.	100	2020-01-14	2034-01-14	2,816.00	2,816.00
9320020097	Active	2277445 Alberta Ltd.	100	2020-02-05	2034-02-05	3,072.00	3,072.00
9320070046	Active	2277445 Alberta Ltd.	100	2020-07-22	2034-07-22	3,584.00	3,584.00
9320080011	Active	2277445 Alberta Ltd.	100	2020-08-10	2034-08-10	9,216.00	9,216.00
9321060115	Active	2277445 Alberta Ltd.	100	2021-06-25	2035-06-25	1,280.00	1,280.00
9322040139	Active	2277445 Alberta Ltd.	100	2022-04-27	2036-04-27	552.00	552.00
9322070199	Active	2277445 Alberta Ltd.	100	2022-07-18	2036-07-18	5,888.00	5,888.00
9322070200	Active	2277445 Alberta Ltd.	100	2022-07-18	2036-07-18	6,912.00	6,912.00
9322070201	Active	2277445 Alberta Ltd.	100	2022-07-18	2036-07-18	9,216.00	9,216.00
9322070202	Active	2277445 Alberta Ltd.	100	2022-07-18	2036-07-18	6,912.00	6,912.00
9322070203	Active	2277445 Alberta Ltd.	100	2022-07-18	2036-07-18	6,912.00	6,912.00
9322070204	Active	2277445 Alberta Ltd.	100	2022-07-18	2036-07-18	4,014.66	4,014.66
9322070205	Active	2277445 Alberta Ltd.	100	2022-07-18	2036-07-18	7,424.00	7,424.00
9322070206	Active	2277445 Alberta Ltd.	100	2022-07-18	2036-07-18	9,216.00	9,216.00
9322070207	Active	2277445 Alberta Ltd.	100	2022-07-18	2036-07-18	9,122.78	9,122.78
9322070208	Active	2277445 Alberta Ltd.	100	2022-07-18	2036-07-18	9,216.00	9,216.00
9322070217	Active	2277445 Alberta Ltd.	100	2022-07-19	2036-07-19	8,960.00	8,960.00
9322070218	Active	2277445 Alberta Ltd.	100	2022-07-19	2036-07-19	3,072.00	3,072.00
9322070219	Active	2277445 Alberta Ltd.	100	2022-07-19	2036-07-19	4,799.22	4,799.22
9322070220	Active	2277445 Alberta Ltd.	100	2022-07-19	2036-07-19	6,144.00	6,144.00
9322070221	Active	2277445 Alberta Ltd.	100	2022-07-19	2036-07-19	4,571.99	4,571.99
9322070265	Active	2277445 Alberta Ltd.	100	2022-07-28	2036-07-28	9,216.00	9,216.00
9322080140	Active	2277445 Alberta Ltd.	100	2022-08-12	2036-08-12	8,912.00	8,912.00
9322080141	Active	2277445 Alberta Ltd.	100	2022-08-12	2036-08-12	9,216.00	9,216.00
9322080142	Active	2277445 Alberta Ltd.	100	2022-08-12	2036-08-12	8,560.00	8,560.00
9322080143	Active	2277445 Alberta Ltd.	100	2022-08-12	2036-08-12	3,872.00	3,872.00
9322080144	Active	2277445 Alberta Ltd.	100	2022-08-12	2036-08-12	7,056.00	7,056.00
9322080145	Active	2277445 Alberta Ltd.	100	2022-08-12	2036-08-12	8,816.84	8,816.84
9322100180	Active	2277445 Alberta Ltd.	100	2022-10-06	2036-10-06	512.00	512.00
9322100181	Active	2277445 Alberta Ltd.	100	2022-10-06	2036-10-06	6,998.32	6,998.32
9322100182	Active	2277445 Alberta Ltd.	100	2022-10-06	2036-10-06	9,216.00	4,554.02
9322100183	Active	2277445 Alberta Ltd.	100	2022-10-06	2036-10-06	9,216.00	9,216.00
9322100184	Active	2277445 Alberta Ltd.	100	2022-10-06	2036-10-06	7,805.10	4,956.11
9322100237	Active	2277445 Alberta Ltd.	100	2022-10-24	2036-10-24	7,680.00	5,090.01
9322100238	Active	2277445 Alberta Ltd.	100	2022-10-24	2036-10-24	9,216.00	/
9322100239	Active	2277445 Alberta Ltd.	100	2022-10-24	2036-10-24	6,128.34	/
9322100240	Active	2277445 Alberta Ltd.	100	2022-10-24	2036-10-24	2,107.49	2,107.49
9322110194	Active	2277445 Alberta Ltd.	100	2022-11-24	2036-11-24	9,216.00	9,216.00
9322110195	Active	2277445 Alberta Ltd.	100	2022-11-24	2036-11-24	9,216.00	9,216.00
9322110196	Active	2277445 Alberta Ltd.	100	2022-11-24	2036-11-24	8,261.66	6,189.67
9322110197	Active	2277445 Alberta Ltd.	100	2022-11-24	2036-11-24	9,216.00	9,216.00
9322110199	Active	2277445 Alberta Ltd.	100	2022-11-24	2036-11-24	9,216.00	9,216.00
9322110200	Active	2277445 Alberta Ltd.	100	2022-11-24	2036-11-24	9,216.00	9,216.00
9322110201	Active	2277445 Alberta Ltd.	100	2022-11-24	2036-11-24	9,216.00	7,662.01
9322110202	Active	2277445 Alberta Ltd.	100	2022-11-24	2036-11-24	9,216.00	8,180.00
Total permits: 82 to Dec. 31, 2023 (79 in conversion)					**Total area**	**623,403.90**	**553,773.54**
Total permits to Dec. 31, 2023: 118 **Total permits/licences being converted: 110**					**Total area (ha) (all properties)**	**898,220.65**	**760,345.84**

MIMP = Metallic and Industrial Mineral Permit (to December 31, 2023)
RHMP = Rock-Hosted Mineral Permit (currently being converted by the Government of Alberta at the Effective Date of this technical report).
BHMP = Brine-Hosted Mineral Licence (currently being converted by the Government of Alberta at the Effective Date of this technical report).

Figure 4.1: Permit/licence descriptions for LithiumBank's Alberta-based lithium-brine properties. The Boardwalk Property mineral permits/licences are highlighted in grey. Permit/licence areas are presented as Metallic and Industrial Mineral Permits (to December 31, 2023) and as Rock- and Brine-Hosted Mineral Permits/Licences that are currently being converted by the Government of Alberta into the new tenure regulation structure at the Effective Date of this technical report.

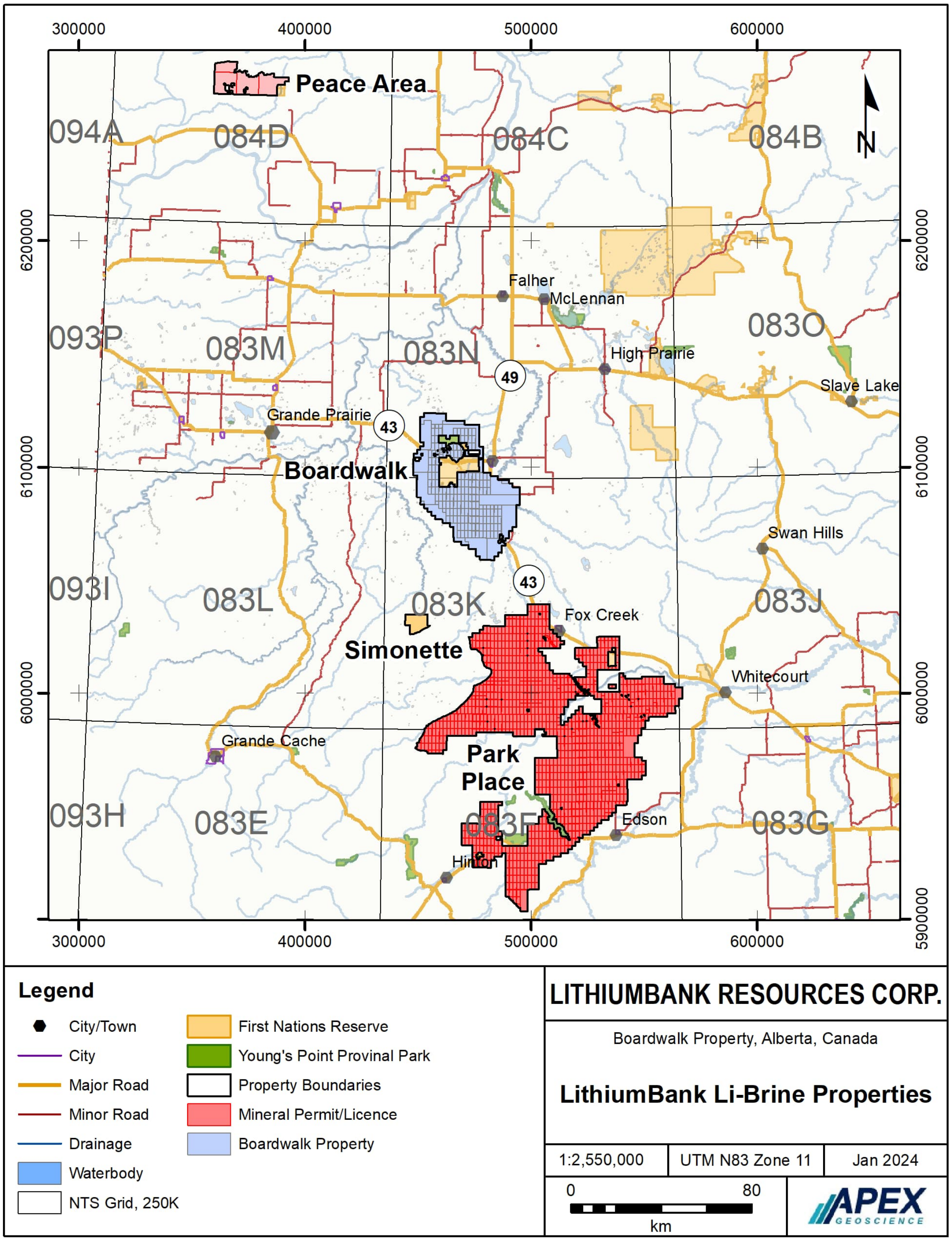


Figure 4.2: Overview of LithiumBank's Alberta lithium-brine properties. This Technical Report focuses on the Boardwalk Property

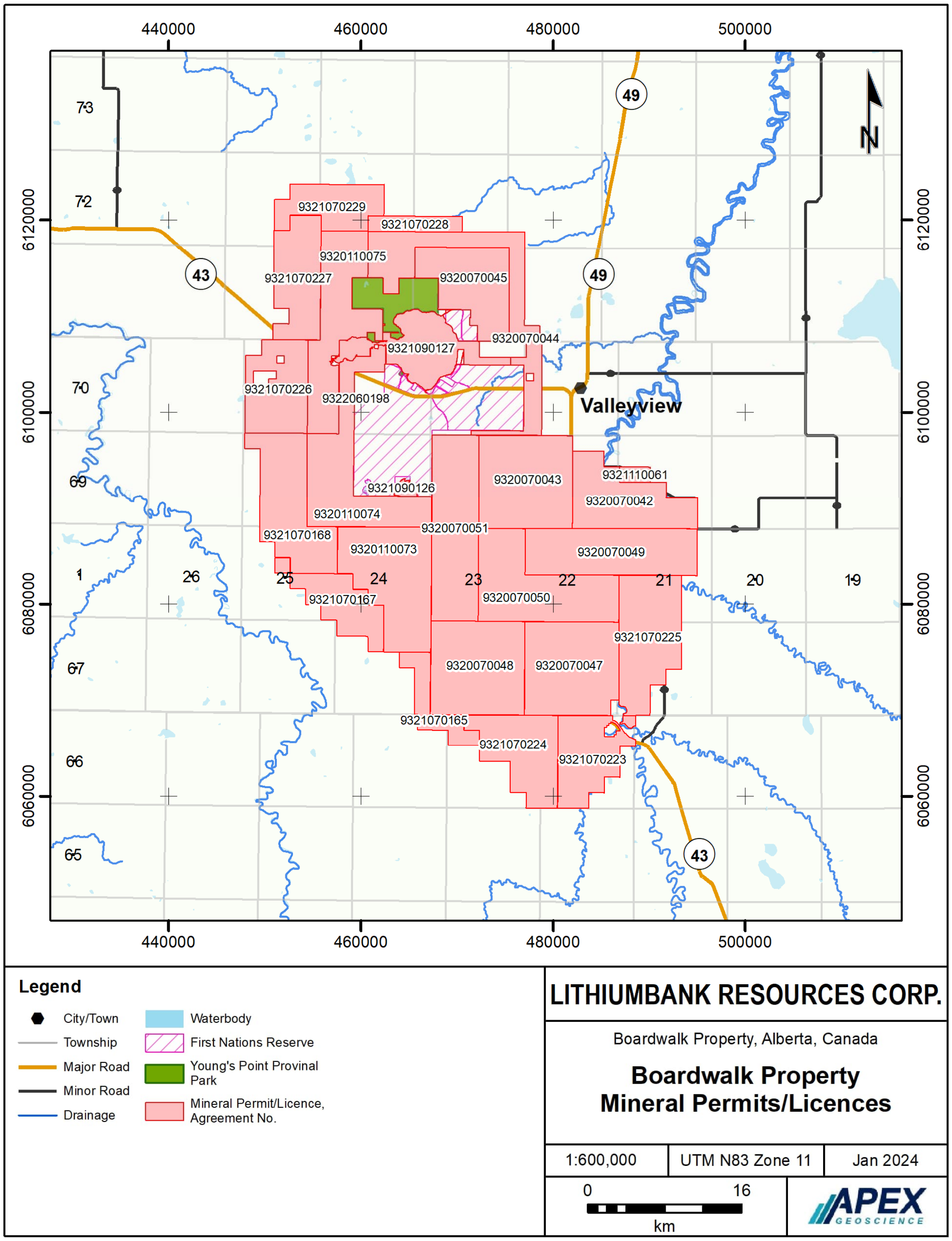


Figure 4.3: Spatial summary of individual permits/licences at LithiumBank's Boardwalk Property

Metallic and Industrial Mineral Permit Descriptions (as of December 31, 2023 and prior to new [Jan 1, 2024] Alberta Mineral Tenure Regulation)							Recent Permit/Licence Application Summary (in accordance with new [Jan 1, 2023] Alberta Mineral Tenure Regulation)		
Agreement Number	**Status**	**Designated Representative**	**Owner-ship (%)**	**Size (ha)**	**Term date**	**Expiry date**	**Conversion to Rock-Hosted Mineral Permits and Brine-Hosted Mineral Licences (excluded application ATS sections)**	**Owner-ship (%)**	**Size (ha)**
9320070042	Active	2277445 Alberta Ltd.	100	9,216.00	2020-07-22	2034-07-22	Yes (excluding sections 5-21-069:01, 5-21-069:12, 5-21-069:13, 5-21-069:14, 5-21-069:15, 5-22-069:25, 5-22-069:34, 5-22-069:35, 5-22-069:36)	100	6,885.01
9320070043	Active	2277445 Alberta Ltd.	100	9,216.00	2020-07-22	2034-07-22	Yes	100	9,216.00
9320070044	Active	2277445 Alberta Ltd.	100	8,148.60	2020-07-22	2034-07-22	Yes	100	8,148.60
9320070045	Active	2277445 Alberta Ltd.	100	6,518.70	2020-07-22	2034-07-22	Yes	100	6,518.70
9320070047	Active	2277445 Alberta Ltd.	100	9,088.00	2020-07-22	2034-07-22	Yes	100	9,088.00
9320070048	Active	2277445 Alberta Ltd.	100	9,216.00	2020-07-22	2034-07-22	Yes	100	9,216.00
9320070049	Active	2277445 Alberta Ltd.	100	9,216.00	2020-07-22	2034-07-22	Yes (excluding sections 5-21-068:24, 5-21-068:25, 5-21-068:36)	100	8,439.00
9320070050	Active	2277445 Alberta Ltd.	100	9,216.00	2020-07-22	2034-07-22	Yes	100	9,216.00
9320070051	Active	2277445 Alberta Ltd.	100	9,216.00	2020-07-22	2034-07-22	Yes	100	9,216.00
9320110073	Active	2277445 Alberta Ltd.	100	9,216.00	2020-11-09	2034-11-09	Yes	100	9,216.00
9320110074	Active	2277445 Alberta Ltd.	100	9,042.18	2020-11-09	2034-11-09	Yes	100	9,042.18
9320110075	Active	2277445 Alberta Ltd.	100	8,252.76	2020-11-09	2034-11-09	Yes	100	8,252.76
9321010123	Active	2277445 Alberta Ltd.	100	9,216.00	2021-01-26	2035-01-26	No	/	/
9321010124	Active	2277445 Alberta Ltd.	100	4,053.60	2021-01-26	2035-01-26	No	/	/
9321060158	Active	2277445 Alberta Ltd.	100	1,024.00	2021-02-18	2035-06-25	No	/	/
9321070164	Active	2277445 Alberta Ltd.	100	6,144.00	2021-02-10	2035-07-09	No	/	/
9321070165	Active	2277445 Alberta Ltd.	100	8,704.00	2021-02-10	2035-07-09	Yes (excluding sections 5-23-066:19, 5-23-066:30, 5-24-066:31, 5-24-066:32, 5-24-066:33, 5-24-066:34, 5-24-067:02, 5-24-067:03, 5-24-067:0, 5-24-067:05, 5-24-067:06, 5-24-067:07, 5-24-067:08, 5-24-067:09, 5-24-067:10, 5-24-067:11)	100	4,560.02
9321070166	Active	2277445 Alberta Ltd.	100	9,216.00	2021-02-10	2035-07-09	No	/	/
9321070167	Active	2277445 Alberta Ltd.	100	9,216.00	2021-02-10	2035-07-09	Yes (excluding sections 5-24-067:29, 5-24-067:30, 5-24-067:31, 5-25-067:01, 5-25-067:02, 5-25-067:03, 5-25-067:11, 5-25-067:12, 5-25-067:13, 5-25-067:14, 5-25-067:22, 5-25-067:23, 5-25-067:24, 5-25-067:25, 5-25-067:26, 5-25-067:27, 5-25-067:35, 5-25-067:36, 5-25-068:02, 5-25-068:10)	100	4,036.02
9321070168	Active	2277445 Alberta Ltd.	100	9,216.00	2021-02-10	2035-07-09	Yes (excluding sections 5-25-069:06, 5-25-069:07, 5-25-069:18, 5-25-069:19, 5-25-069:30)	100	7,921.01
9321070223	Active	2277445 Alberta Ltd.	100	8,690.20	2021-04-28	2035-07-16	Yes (excluding sections 5-21-066:06, 5-21-066:07, 5-21-066:18, 5-21-066:19, 5-21-066:30, 5-21-066:31, 5-22-066:01, 5-22-066:02, 5-22-066:03, 5-22-066:11, 5-22-066:12, 5-22-066:13, 5-22-066:24)	100	5,323.21
9321070224	Active	2277445 Alberta Ltd.	100	8,960.00	2021-04-28	2035-07-16	Yes (excluding sections 5-23-066:02, 5-23-066:03, 5-23-066:04, 5-23-066:08, 5-23-066:09, 5-23-066:10, 5-23-066:15, 5-23-066:16, 5-23-066:17, 5-23-066:18, 5-23-066:20)	100	6,111.01
9321070225	Active	2277445 Alberta Ltd.	100	8,889.90	2021-04-28	2035-07-16	Yes (excluding sections 5-21-067:03, 5-21-067:04, 5-21-067:09, 5-21-067:10)	100	7,853.90
9321070226	Active	2277445 Alberta Ltd.	100	8,832.00	2021-04-28	2035-07-16	Yes (excluding sections 5-25-070:31, 5-26-070:01, 5-26-070:02, 5-26-070:11, 5-26-070:12, 5-26-070:13, 5-26-070:14, 5-26-070:23, 5-26-070:24, 5-26-070:25, 5-26-070:26, 5-26-070:35, 5-26-070:36)	100	5,465.01
9321070227	Active	2277445 Alberta Ltd.	100	9,216.00	2021-04-28	2035-07-16	Yes (excluding sections 5-25-071:04, 5-25-071:09, 5-25-071:10, 5-25-071:16, 5-25-071:21, 5-25-071:28, 5-25-071:33, 5-25-072:04, 5-25-072:05, 5-25-072:07, 5-25-072:08, 5-25-072:09, 5-25-072:17, 5-25-072:18)	100	5,590.01
9321070228	Active	2277445 Alberta Ltd.	100	7,168.00	2021-04-28	2035-07-16	Yes (excluding sections 5-25-071:04, 5-25-071:09, 5-25-071:10, 5-25-071:16, 5-25-071:21, 5-25-071:28, 5-25-071:33, 5-25-072:04, 5-25-072:05, 5-25-072:07, 5-25-072:08, 5-25-072:09, 5-25-072:17, 5-25-072:18)	100	1,470.02
9321070229	Active	2277445 Alberta Ltd.	100	9,216.00	2021-04-28	2035-07-16	Yes (excluding sections 5-24-072:27, 5-24-072:28, 5-24-072:29, 5-24-072:30, 5-24-072:31, 5-24-072:32, 5-24-072:33, 5-24-072:34, 5-25-072:16, 5-25-072:20, 5-25-072:21, 5-25-072:22, 5-25-072:25, 5-25-072:26, 5-25-072:27, 5-25-072:28, 5-25-072:34, 5-25-072:35, 5-25-072:36)	100	4,295.02
9321090126	Active	2277445 Alberta Ltd.	100	324.23	2021-09-29	2035-09-29	Yes	100	324.23
9321090127	Active	2277445 Alberta Ltd.	100	5,740.36	2021-04-28	2035-09-29	Yes	100	5,740.36
9322060198	Active	2277445 Alberta Ltd.	100	64.00	2022-06-07	2036-06-07	Yes	100	64.00
9321110061	Active	2277445 Alberta Ltd.	100	9,216.00	2021-11-18	2035-11-18	Yes	100	9,216.00
Total permits/area	**31**			**238,668.53**			**26**		**170,424.08**

Figure 4.4: A summary of the conversion of Alberta Metallic and Industrial Metal Mineral Permits (as of December 31, 2024) to Rock-Hosted Mineral Permits and Brine-Hosted Mineral Licences at the Boardwalk Property in accordance with Alberta's new mineral tenure reg

4.3.1 *Host-Rock Mineral Permits*

The Host-Rock Mineral Permits grant LithiumBank the exclusive right to explore for metallic and industrial minerals for seven consecutive two-year terms (14 years), subject to the submission of biannual assessment work to keep the permits in good standing. Work requirements to maintain the permits in good standing are \$5.00/ha for the 1st term, \$10.00/ha for each of the 2nd and 3rd terms, and \$15.00/ha for each the 4th, 5th, 6th, and 7th terms.

The statutes also provide for conversion of Host-Rick Mineral Permits to Host-Rick Mineral Leases once a mineral deposit has been identified. The term of a Lease is 15 years, and it may be renewed. Annual rent is payable in the amount determined under the lease.

Complete terms and conditions for mineral exploration permitting and work can be found in the Alberta *Mines and Minerals Act* (Metallic and Industrial Minerals Tenure Regulation, December 21, 2022).

4.3.2 *Brine-Hosted Minerals Licences*

A Brine-Hosted Mineral Licence grants the holder 1) the exclusive right to explore for brine-hosted metallic and industrial minerals in the subsurface strata within and under the location described in the licence, and 2) the right to remove samples of brine-hosted metallic and industrial minerals from the location described in the licence for the purposes of testing and of other scientific studies. The term of a Brine-Hosted Mineral Licence is 5 years beginning on the licence term commencement date. Brine-hosted minerals licences require payment of annual rental of \$3.50 per ha. Brine-hosted minerals licences do not have a minimum exploration requirement; exploration activity and reporting are not required to keep a brine-hosted licence in good standing.

A Brine-Hosted Mineral Licence must not be renewed, extended, or continued. The holder of a Brine-Hosted Mineral Licence can apply for a Brine-Hosted Mineral Lease for the whole, or a portion, of the location described in the licence providing the lease application area is the same, or within the same area, as the location described in the licence. The area, boundaries, and configuration of the Brine-Hosted Mineral Lease must not exceed 2,304 ha and must be approved by the Minister. The initial term of a Brine-Hosted Mineral Lease is 10 years beginning on the lease term commencement date. The initial term of a Brine-Hosted Mineral Lease can be continued for an indefinite term if the Minister is satisfied that the holder follows the *Alberta Minerals Act*. LithiumBank has yet to apply for Brine-Hosted Mineral Leases (only licences).

4.4 Coexisting Oil & Gas, Oil Sands, Coal, and Metallic and Industrial Mineral Rights

In Alberta, rights to metallic and industrial minerals, to bitumen (oil sands), to coal and to oil/gas are regulated under separate statutes, which collectively make it possible for several different 'rights' to coexist and be held by 'different grantees' over the same geographic location. Oil/gas leases owned by various Petro-operators and LithiumBank's Alberta Metallic and Industrial Mineral Permits coexist in the Valleyview area and in the vicinity of, and under, LithiumBank's Property. A summary of the oil and gas wells in the Boardwalk Property area is presented in Section 6, History. There are no known coal or oil sands rights in the Property area.

4.5 Royalties and Agreements

Government royalty rates associated with any Li-production in Alberta, as administrated by the Department of Energy, would be subject to 1% gross mine-mouth revenue before payout, and after payout, the greater of 1% gross mine-mouth revenue and 12% net revenue. Alberta Metallic and Industrial Mineral Permits at the Boardwalk Property were acquired directly via on-line staking from the Government of Alberta. Consequently, there are no known back-in rights, payments, or other agreements and encumbrances to which the Property is subject.

4.6 Permitting

In Alberta, the Rock-Hosted Mineral Permit and Brine-Hosted Mineral Licence grants the holder the exclusive right to explore for and acquire rock and brine samples for testing and other scientific studies.

With respect to lithium-brine and the development or operation of any future brine well or facility for minerals extraction, the *Mineral Resource Development Act* came into effect for brine-hosted mineral development on March 1, 2023. Combined with the *Responsible Energy Development Act*, the *Mineral Resource Development Act* provides legislative authority to the Alberta Energy Regulator (AER) to regulate mineral resources and ensure their safe, efficient, orderly, and responsible development. The directive sets out the AER's requirements for developing brine-hosted mineral resources, and are applicable to, the entire life cycle of the brine-hosted mineral development: initiation, construction, operation, and closure.

Subject to the regulations and rules, no person shall proceed with the following schemes unless the AER has granted an approval for the scheme on any terms and conditions prescribed by the Regulator: 1) the gathering, storage and disposal of water produced in connection with the development of mineral resources; 2) the injection, storage or disposal of any fluid or other substance associated with the development of mineral resources to an underground formation through a well; 3) an experimental scheme; 4) the concurrent production of energy resources and associated mineral resources; 5) the storage, treatment, processing or disposal of waste associated with the development of mineral resources; 6) the enhanced recovery of mineral resources.

Under the terms of the *Mineral Resource Development Act,* the regulator may designate a well, or all or part of a facility, as defined within the *Oil and Gas Conservation Act* or *Geothermal Resource Conservation Act*. No person shall develop a mine site, operate a mine, construct, or operate a processing plant until the person holds a permit, licence, and approval that is in full force for the activity. A permittee or licensee must prepare, keep, and provide to the AER mine plans in accordance with the rules.

4.7 Brine Access Agreement

LithiumBank's mineral of interest (lithium) within the Boardwalk Property is hosted in the confined Devonian aquifer at depths of between 2,338 m and 3,051 m below the Earth's surface. LithiumBank does not own any subsurface reservoir leases or deep subsurface well(s) and equipment that is capable of pumping brine from these depths to the surface for testing. LithiumBank is therefore reliant on existing Petro-operators to gain access to oil and gas leases and associated infrastructure to conduct early-stage exploration work that involves brine assay testing and/or mineral processing technological test work. Access to the lease and brine is acquired through a request to the Petro-operator and/or an agreement between the Li-brine exploration company and the controlling Petro-operator.

On 14 May 2021, LithiumBank completed a brine access agreement with a major Petro-operator in control of the Sturgeon Lake South and Sturgeon Lake North Oilfields. The agreement permits LithiumBank to obtain brine from the existing oil and gas infrastructure for the purpose of exploration work (i.e., assaying, and mineral processing test work). This agreement includes access to the currently suspended wells, in which the Petro-operator has agreed to reopen a select number of wells that will enable LithiumBank access to the Leduc Formation aquifer brine. The agreement details re-accessing a set number of suspended wells that will include setting up a rig-up swab unit, P-tank, flare stack, vac and pressure trucks, pressure test to 7 MPa for 7 minutes, flowing the well to obtain a sufficient brine sample, rig out the equipment, and leave the wellsite in an AER compliant state. Once the brine is collected, the wells would then be returned to their suspended state by the Petro-operator.

It should be noted that LithiumBank's brine access agreement is related to exploratory brine test work only and the Company has yet to develop a brine production agreement with a Petro-operator and/or acquired permits to drill its own brine wells as part of an advanced Li-brine project.

4.8 Surface Rights

At the early exploration stage, LithiumBank is completely reliant on the Petro-operators permission for access to their lease permits to acquire brine for test purposes. Any permits and licences associated with the lease including land use, rigs, pipelines, processing facilities, road permits, water permits, injection wells, surface rights, reservoir rights, etc., have been granted exclusively to the oil and gas company.

Upon approval from the Petro-operator, the collection of the brine is conducted under the rules and guidance of the Petro-operator lease protocols. LithiumBank's brine sampling methodology does not require additional permits, or surface and access approval beyond the actual Alberta Metallic and Industrial Mineral Permit.

If LithiumBank were to drill a deep exploration or production well, or acquire an oilfield, the Company would be required to comply with well licence application requirements as administrated by the Alberta Energy Regulator (AER) who regulates various acts and the regulations focused on energy exploration and production in Alberta.

4.9 Environmental Liabilities and Significant Factors

Effective March 29, 2014, the Alberta Energy Regulator (AER) took over jurisdictional responsibility for water and the environment with respect to energy resource activities in Alberta from Alberta Environment and Sustainable Resource Development. The AER regulates activities at the project initiation, construction, operation, closure, and remediation and reclamation stages to ensure safe, efficient, orderly, and environmentally responsible development.

While the AER acts as a “one-stop regulator”, the performance of a well and/or facility operation in accordance with a permit, licence, or approval does not relieve the permittee, licensee or approval holder from the requirements or liabilities arising under any other Act or otherwise (e.g., *Alberta Land Stewardship Act*, *Environmental Protection and Enhancement Act*, AER Directive 056: Energy Development Applications and Schedules). For example, the requirement for an *Environmental Protection and Enhancement Act* (EPEA) approval for any future brine facility or operation is currently being amended in the Activities Designation Regulation under EPEA (“brine-hosted mineral resource processing plant”), which is the responsibility of the Alberta Ministry of Environment and Protected Areas. The EPEA was amended on March 1, 2023, however, the revised EPEA is not available via the King’s Printer at the Effective Date of this technical report.

LithiumBank’s mineral permits/licenses occur adjacent to two (2) (of three (3)) Sturgeon Lake First Nation Reserves, 154 and 154A (Figure 4.1). Sturgeon Lake 154 is located on Highway 43, 3.5 km west of the Town of Valleyview. Sturgeon Lake 154A is located on the northeast corner of Sturgeon Lake. The reserves are under the administration of the Sturgeon Lake First Nation. The Sturgeon Lake Community conducts youth job training programs and community news can be accessed at: http://www.slfn.ca/.

Young’s Point Provincial Park is in the northwestern portion of the Boardwalk Property area (Figure 4.3). It is located on the north shore of Sturgeon Lake, 23 km west of Valleyview. The Park was established on 3 August 1971, to protect the boreal forest ecosystem. The Park has an area of 30.5 km² and includes a campground, a boat launch facility and day use area. The Park is operational from May 1 to September 30.

Specific land use conditions for the Boardwalk Property are included with the Alberta Energy Metallic and Industrial Mineral Disposition of Mineral Rights data (https://gis.energy.gov.ab.ca/Geoview/Metallic).

Environmental restrictions as they pertain to the Boardwalk Property include:

- Trumpeter Swan Habitat: Buffer zone around small lakes/marshes throughout the Boardwalk Property. The restriction is for all minerals from surface to basement and is designed to protect the breeding habitat, reduce industrial disturbance to, and minimize access created near Swan Lakes, to allow the continued recovery of the Trumpeter Swan. Guidelines for the disposition holder: 1) no activity from April 1 to September 30 of each year within 800 m of the high-water mark of identified lakes or water bodies; 2) no direct flights over identified lakes or water bodies from April 1 to September 30 of each year; 3) no access development within 500 m of the high-water mark on identified lakes and bodies.

- Key Wildlife and Biodiversity Zones: The far eastern edge of the Boardwalk Property is designated as a restriction zone for all minerals from surface basement. The restriction is in place to protect ungulate winter habitat and habitat with higher potential for biodiversity (habitat along river valleys and south-facing slopes). Guidelines for the disposition holder: 1) to not conduct any activity from January 15 to April 30 of each year for activities north of Highway #1; 2) if necessary, temporary access should be designed to minimize disturbance to wildlife and degradation of associated habitat; and 3) all winter activities will be designed to be completed prior to timing restrictions.
- With respect to significant factors, as with any early-stage exploration project there exists potential risks and uncertainties. LithiumBank will attempt to reduce risk/uncertainty through effective project management, engaging technical experts, and developing contingency plans. LithiumBank is reliant on pre-existing oil and gas wells that are managed and operated by current Petro-companies. Hence there is some risk associated with a dependency on the Petro-operation and continued brine access. It is possible that situations could arise where the Petro-companies shut down well production. As a mitigation strategy, LithiumBank could permit and drill their own wells at the Property or consider options such as purchasing the well, renting the operation of the well, or drilling their own well(s).

To the best of the QPs knowledge, there are no other significant factors that may affect access, title or right or ability to perform exploration work for the purposes of testing and conducting scientific studies on Leduc Formation aquifer brine at the Boardwalk Property.

5. Accessibility, Climate, Local Resources, Infrastructure and Physiography

5.1 Accessibility

The Property has highway access but no rail access. The closest air access is a public airport located 3.5 km south of the Town of Valleyview. Valleyview is located at the junction of Alberta Provincial Highway 43 (Hwy 43) and Highway 49 (Figure 5.1). Hwy 43 runs north-south through the Boardwalk Property. The Property can also be accessed by secondary one or two-lane all-weather roads.

Access within the property is facilitated by numerous all weather and dry weather gravel roads, many of which are serviced year-round due to oil and gas exploration in the area. Accommodation, food, fuel, and supplies are best obtained in the towns of Valleyview, High Prairie and Fox Creek, AB. Larger urban areas include the City of Grande Prairie, AB, and Town of Whitecourt, AB, which are located 110 km west and 170 km southeast, respectively, from Valleyview.

5.2 Site Topography, Elevation and Vegetation

The Boardwalk Property is situated in the foothill's region of west-central Alberta in an area characterized by hilly topography. Elevation in the region varies from 600 m to 1,380 m above sea level (m asl). The Little Smoky River and the Goose River are the dominant topographic features and dissect the southern and central portions of the property. Additionally, numerous creeks and wetlands occur throughout the property. Forested regions are dominated by aspen, balsam poplar, lodgepole pine and white spruce. Vegetation in the wetland areas is characterized by black spruce, tamarack, and mosses.

5.3 Climate

Valleyview has a humid continental climate (Köppen climate classification *Dfb*). Summers are warm with cool nights. Winters are long and can be severely cold. Annual temperatures range from -40ºC in January to 30ºC in July and August with average temperatures above 0ºC between April and October (Environment Canada, 2011).

Yearly precipitation (as rain and snow) ranges from approximately 14 mm to greater than 100 mm; the greatest amount of precipitation typically occurs in June and July (Environment Canada, 2011).

The oil and gas industry in the region operates year-round, and hence LithiumBank could potentially have access to brine throughout the year. While the climate can be challenging on the coldest winter days, the oil and gas industry has decades of experience and can deal with extreme conditions and in a timely fashion. Accordingly, LithiumBank could conduct exploration activities at the Property year-round.

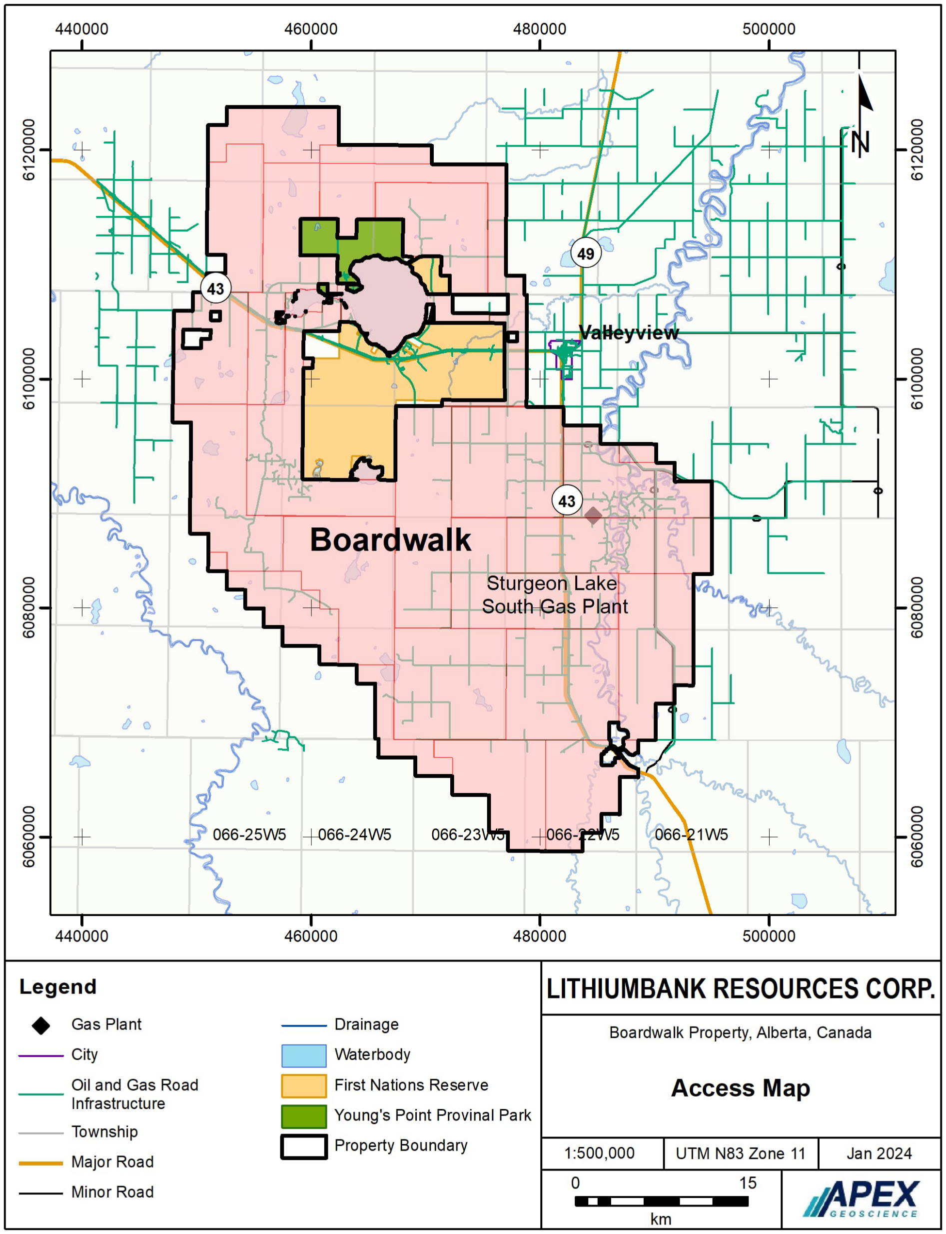


Figure 5.1: Access to, and within, the Boardwalk Property

5.4 Local Resources and Infrastructure

LithiumBank's Boardwalk Property is positioned over the Sturgeon Lake Oilfield, which was discovered in 1952 and continues to produce hydrocarbons today. Thus, the area has experienced 60 years' worth of infrastructure upgrades including major and secondary highways and power lines associated with the development of the Town of Valleyview and the energy resource sector. This is of great benefit to LithiumBank because the current energy resource-related infrastructure provides sufficient power and transportation connections throughout the entire Sturgeon Lake Oilfield, which includes wells, pipelines and plant facilities that are networked throughout the Property area.

The oil and gas industry is the main economic driver in the Municipal District of Greenview, along with forestry and agriculture. In a 2016 Census of Population conducted by Statistics Canada, the Municipal District of Greenview No.16 recorded a population of 5,583 living in 2,067 of its 2,473 total private dwellings. With a land area of 32,984.24 km^2, the Municipal District has a population density of 0.2/km^2. The Town of Valleyview recorded a population of 1,863 living in 747 of its 833 total private dwellings.

To conclude, as a major oil and gas district, the Boardwalk Property has sufficient surface rights legislation and regulations in place to permit major energy resource operations, has ample sources of power, experienced energy resource personnel, and has the potential to expand and/or build additional processing plant sites. I.e., if the appropriate agreements were put in place between the Li-brine and oil and gas operators, any Li-brine processing plant could potentially operate in the same permitted lease space as the current oil and gas plant/facility.

6. History

Information presented in this section relates to historical exploration completed by energy and mineral companies, other than LithiumBank, that has generally occurred within the Boardwalk Property.

6.1 Devonian Oil and Gas Production Summary

Oil and gas well data in the Boardwalk Property area was downloaded during the preparation of this Technical Report using AbaData, an energy industry data software program.
Figure 6.1 shows the distribution of oil and gas wells in the Property area (n=813 wells) and highlights, in red circles, those wells that were used to target the Devonian petroleum system, which include, the Leduc Formation (dominantly so), followed by the Beaverhill Lake Group and rarely the Wabamun Group.

The remaining non-Devonian wells in the region target mostly Triassic and Cretaceous strata, the aquifers of which, are not known to contain elevated levels of lithium (see Section 6.2).

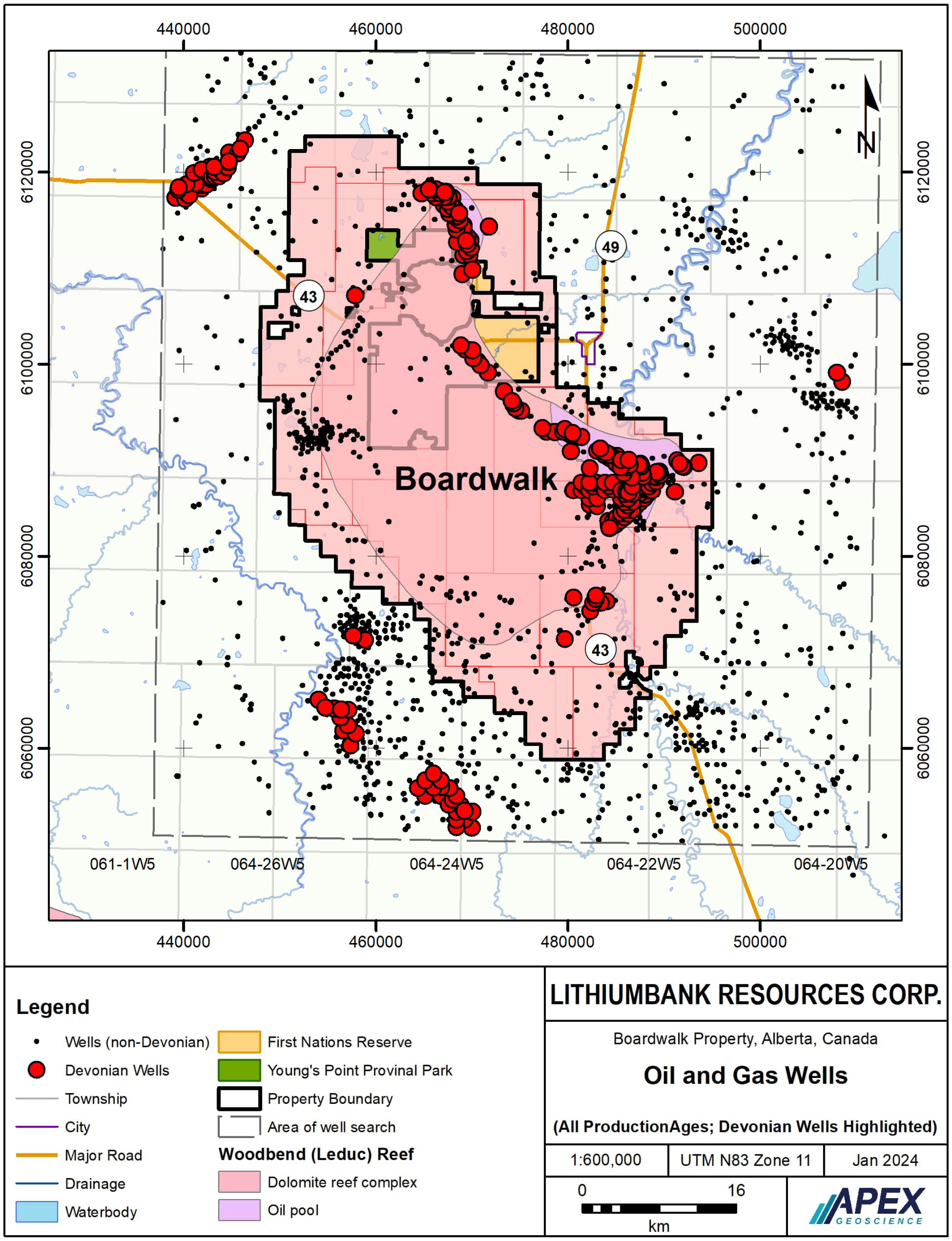


Figure 6.1: Oil and gas wells in the Boardwalk Property area highlighting those wells that have penetrated the Devonian petroleum system (red circles)

The Devonian petroleum system in the Property area occurs within the Sturgeon Lake Reef Complex with most of the production coming from the Sturgeon Lake North and Sturgeon Lake South Oilfields (or pools; Figure 6.2). A total of 242 wells targeted Devonian strata at the Sturgeon Lake Oilfield within the Property. Hydrocarbon production from this field is predominantly from the Leduc D3 pool (93%) followed by significantly less production volume from the Leduc D-1, Leduc D-2, Wabamun Group and Winterburn Group pools. The true vertical depth of the Devonian wells is between 2,337.6 m and 3,050.6 m (average 2,619.9 m).

The status of these Devonian wells is presented in Figure 6.2 and summarized as follows:

- 1 well is listed as pumping oil (well 100/10-01-069-22W5/2).
- 83 wells are suspended oil, and 3 wells are suspended gas (36%).
- 138 wells are abandoned (57%).
- 14 water wells suspended injection, 2 water wells are abandoned, and 1 well is for industrial waste (7%).

The water pipeline infrastructure associated with the Sturgeon Lake Oilfield is presented in Figure 6.3. Wastewater, or brine, from 140 oil and gas wells within the Sturgeon Lake South Oilfield flows into the Sturgeon Lake South Gas Plant. The Facility is also described as STURGEON 2-2-069-22W5 and is located on Township Road 690 approximately 2.7 km east of Highway 43. According to AbaData, and to April 23, 2019, the Sturgeon Lake South Gas Plant has produced:

- 4,425 m^3 oil.
- 1.5 million m^3 gas.
- 183,643 m^3 of brine.

The status of the wells within the field is subject to change as the energy companies can turn wells on or off as mandated. The last recorded production from the Devonian wells is December 2019; this includes the one well listed as actively pumping oil.

Most of the wells in the Boardwalk Property are owned by Canadian Natural Resources Ltd. (CNRL; 82%; Figure 6.4). The second larger producer is Serinus Energy Inc (n=13 wells) who produce from D-2 and D-3B pools. Other companies with more than one well in the oilfield include: Conocophillips Canada Resources Corporation (n=7), BP Canada Energy Group ULC (n=3), Repsol Oil & Gas Company Inc. (n=3), Canlin Energy Corporation (n=2), Paramount Resources Ltd. (n=2), Shell Canada Limited (n=2) and Signalta Resources Limited.

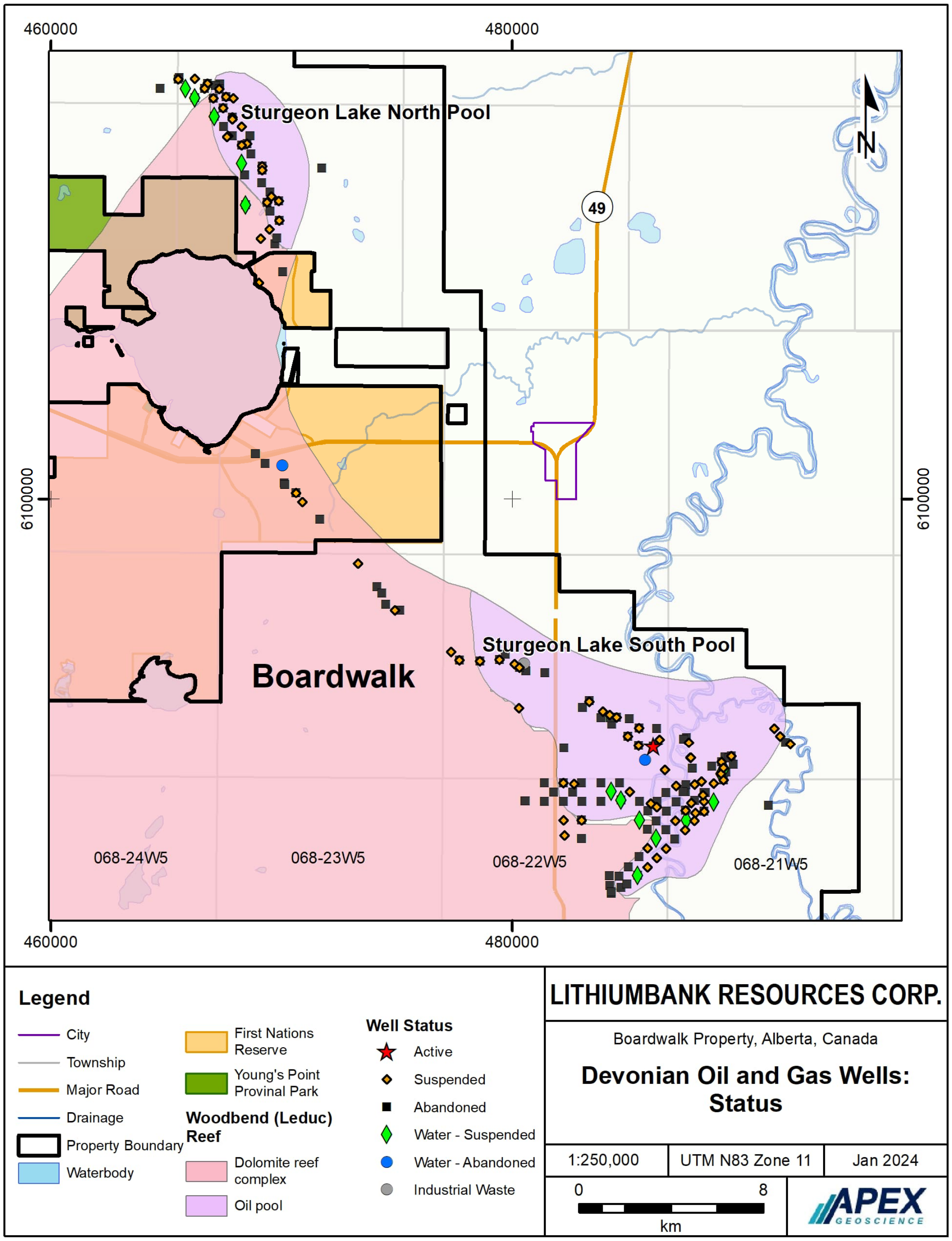


Figure 6.2: Well status of those oil and gas wells penetrating Devonian strata in the Boardwalk Property

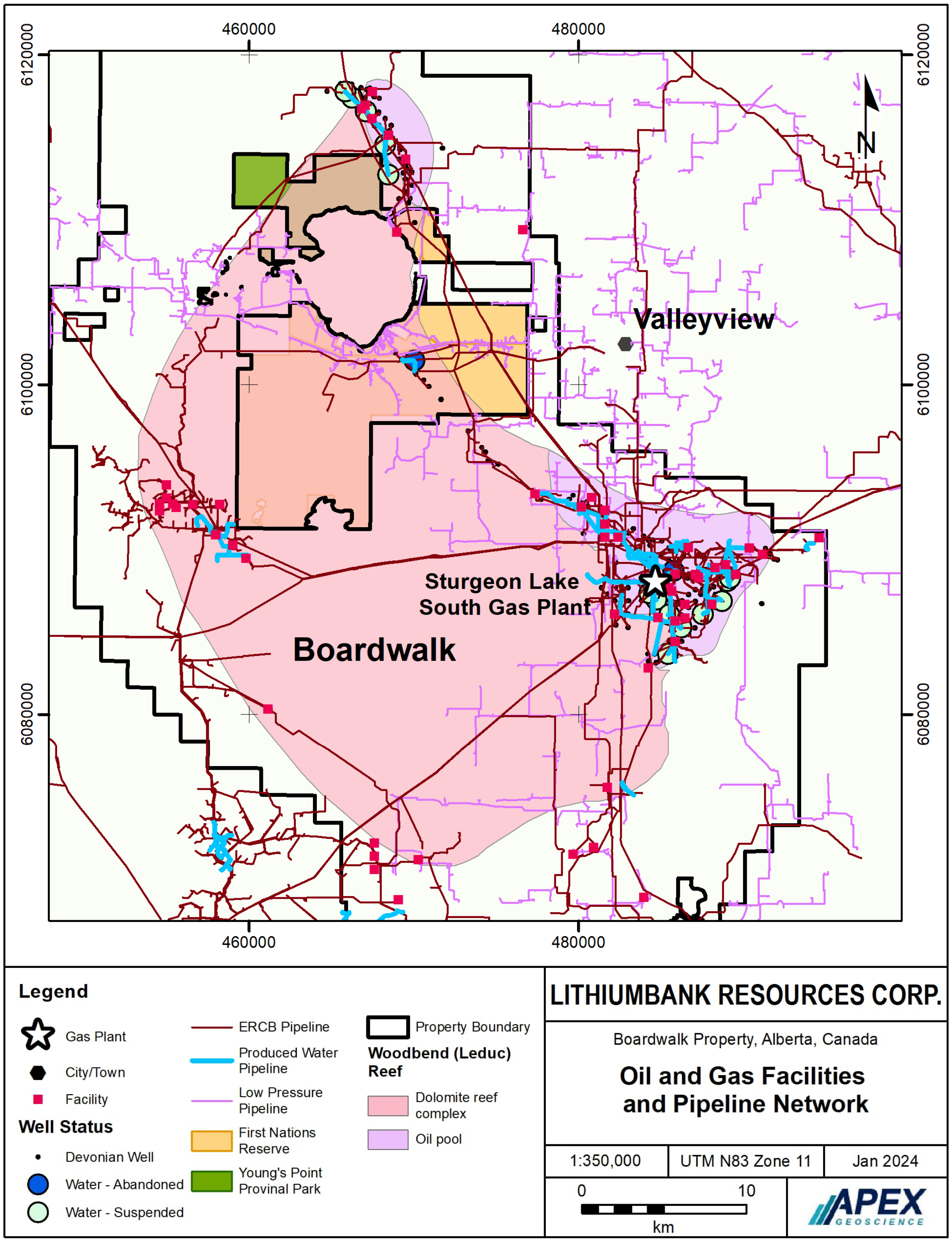


Figure 6.3: Oil and gas facilities and a summary of the pipeline network in the Sturgeon Lake Oilfield

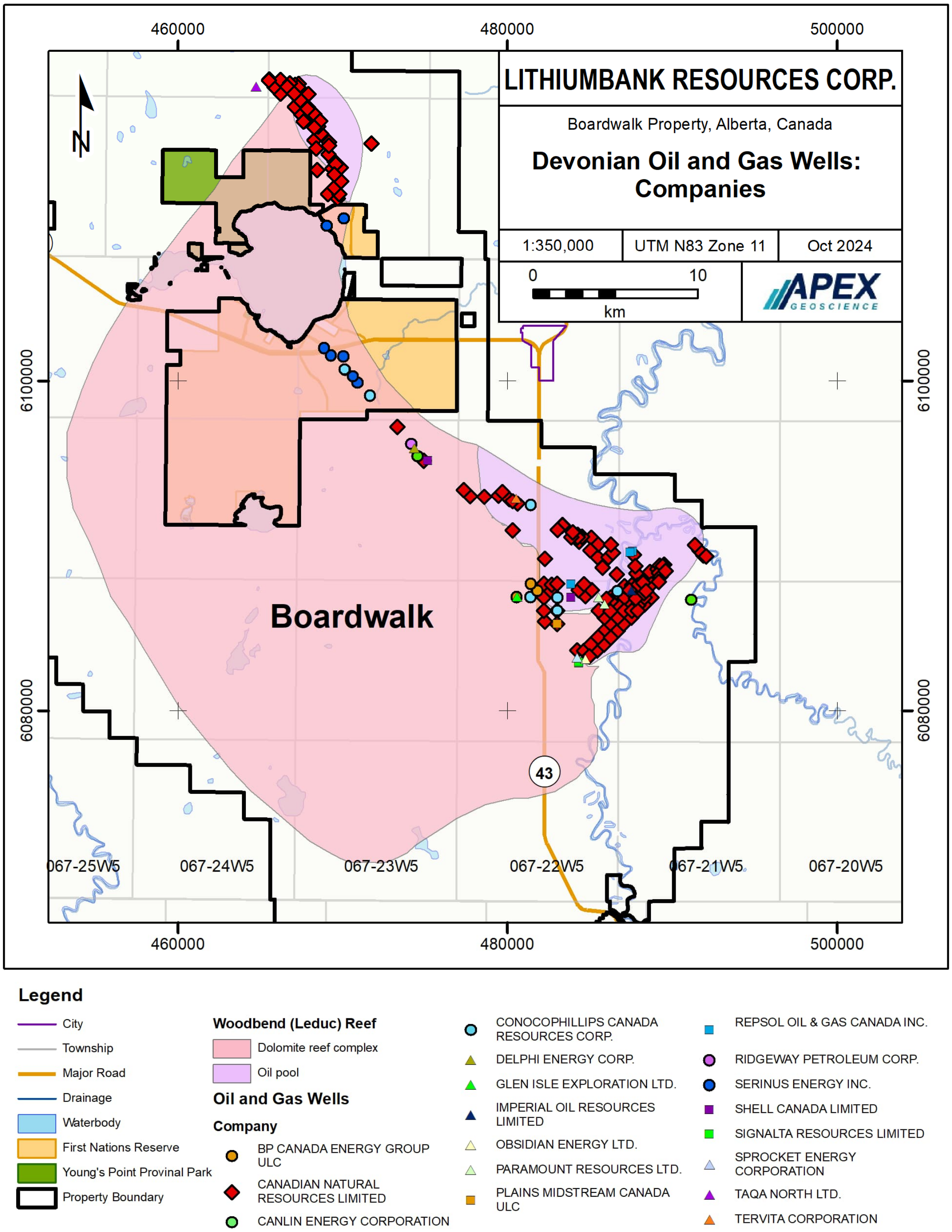


Figure 6.4: Current summary of the Petro-operators at the Boardwalk Property

6.2 Government Lithium-Brine Studies

The first comprehensive overview of Alberta's mineral potential from subsurface formation water was compiled by the Government of Alberta (Hitchon et al., 1995). These authors compiled nearly 130,000 analyses of formation water across Alberta from numerous sources including Alberta Energy Regulator submissions for drilling conducted by the petroleum industry and various Government of Alberta reports (e.g., Hitchon et al., 1971; 1989; Connolly et al., 1990a,b).

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 example, the 'regional exploration threshold value' for lithium was 50 mg/L and the 'detailed exploration threshold value' was defined as 75 mg/L. 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 mg/L).
- 47 analyses had Li concentrations above the 'detailed threshold value' of 75 mg/L.

Hitchon et al. (1995) showed the highest concentrations of Li in formation water occurred within the Beaverhill Lake (Swan Hills) and/or Woodbend (Leduc) aquifers: 130 mg/L and 140 mg/L, respectively (Note: one mg/L is equal to one part per million (ppm)). Further modeling by Underschultz et al. (1994) and Bachu et al. (1995) depicted areas of "significant lithium resources", which correspond to areas of thickened Beaverhill Lake and/or Leduc strata in the Fox Creek region (sites S and BL in Bachu et al., 1995) and in the Boardwalk Property area (site N in Bachu et al., 1995). These authors suggested that the geographic extent of Li-rich formation water in west-central Alberta could cover approximately 75 000 km^2 at prospective depths of between 2,700 and 4,000 m.

In 2010, an expanded Li-brine dataset (n=1,511 analyses) was used to show that lithium is concentrated in several pockets of west-central Alberta, including at the Boardwalk Property area (Figure 6.5; Eccles and Jean, 2010). This compilation indicates that several pockets of concentrated Li exist in west-central Alberta, supporting the conclusions of Hitchon et al. (1995). Of the 1,511 analyses, 19 contained >100 mg/L Li (up to a maximum of 140 mg/L).

Two analytical results of >75 mg/L Li occurred in brine from two separate wells within the Boardwalk Property (84 mg/L and 140 mg/L Li from wells 00/07-27-067-22W5 and 00/13-27-068-22W5, respectively (Figure 6.6).

In 2016, two (2) brine samples collected by Government geologists from the Sturgeon Lake Oilfield supported the historical compilation results; analytical results from these samples yielded 82.7 and 75.4 mg/L Li from wells 102/16-29-071-23W5/2 and 103/05-05-072-23W5/2 (Huff et al., 2019; Figure 6.6).

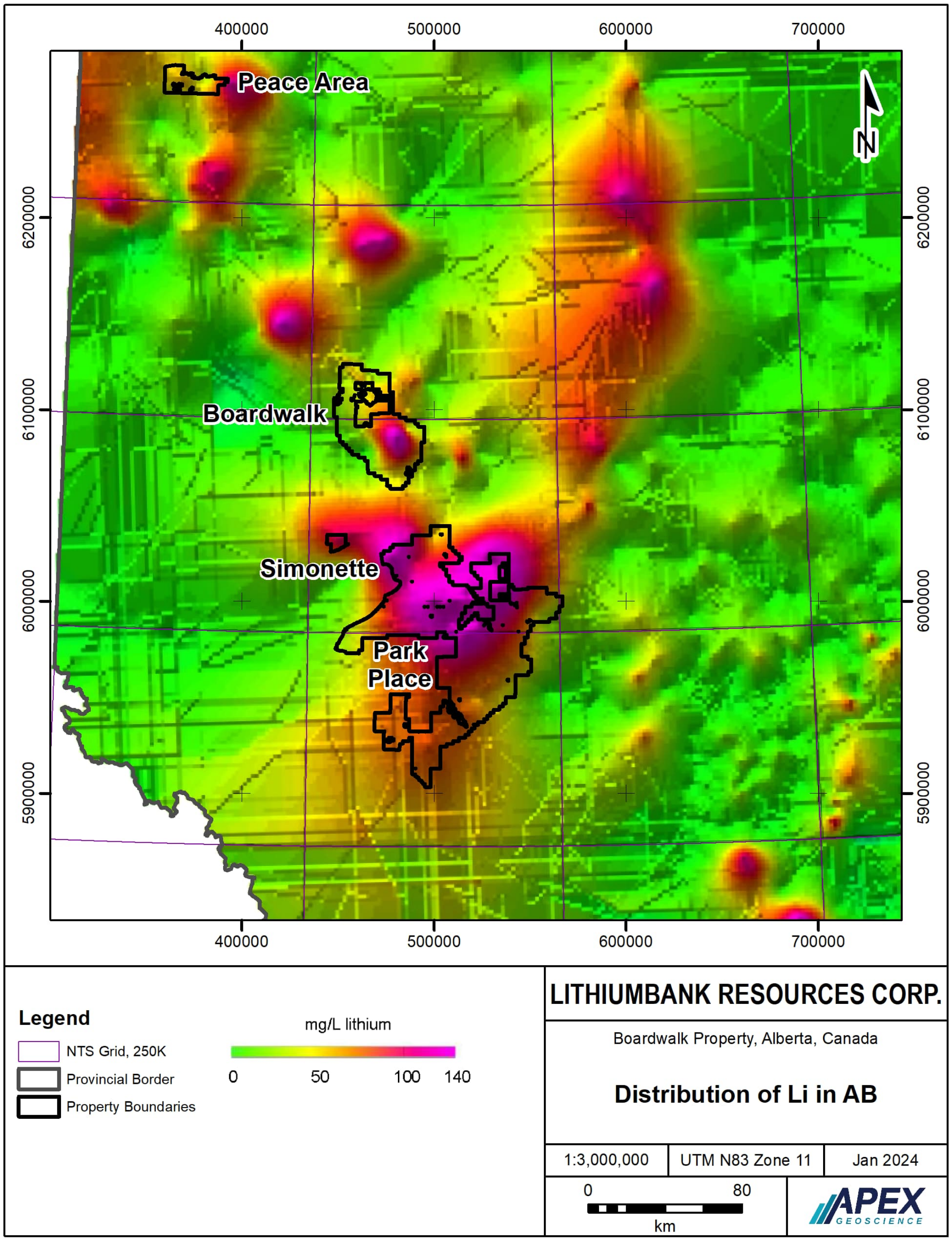


Figure 6.5: Distribution of lithium in Alberta formation waters with LithiumBank's mineral permit sub-properties. Source: Eccles and Jean (2010)

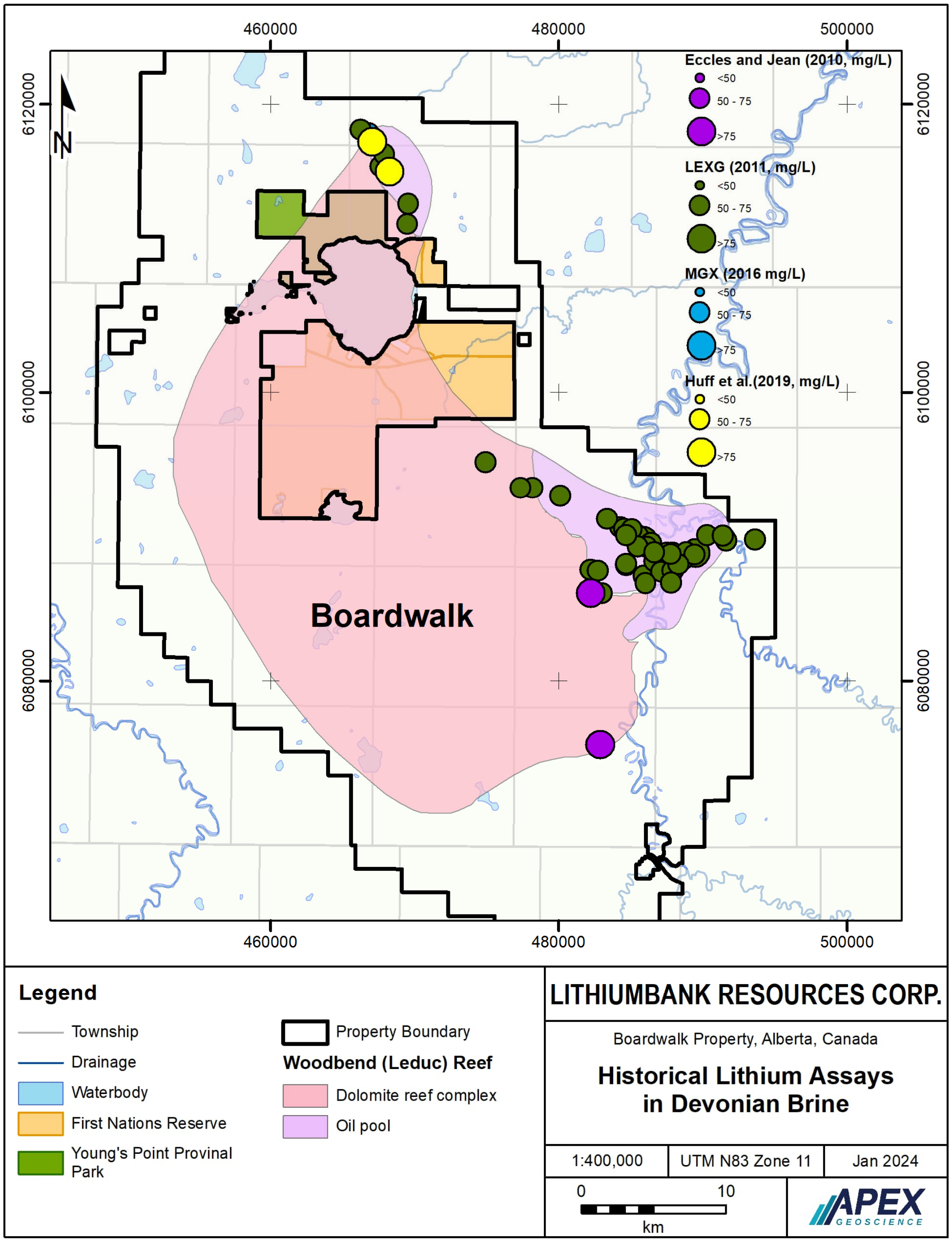


Figure 6.6: Summary of historical government and industry Leduc Formation aquifer brine sampling with lithium analytical results at the Boardwalk Property

6.3 Historical Industry Brine Sampling Programs

Historical brine sampling by companies other than LithiumBank have been conducted by Lithium Exploration Group (LEXG) and MGX Minerals Inc. (MGX). The LEXG and MGX historical sampling programs occurred within the current boundaries of LithiumBank's Boardwalk Property and the sampling programs were supervised by the author of this Technical Report. Hence, the author can comment that the sampling methodology, security, analytical methods, and Quality Assurance – Quality Control (QA-QC) of these historical brine samples was conducted in accordance with standard industry protocol and the analytical results are relevant to the chemical composition of the Leduc Formation aquifer underlying the Boardwalk Property.

6.3.1 2011 LEXG Brine Sampling Program

In 2011, LEXG sampled and analysed brine from 60 wells within the Sturgeon Lake Oilfield. The analytical work was conducted by Maxxam Environmental (now Bureau Veritas) of Edmonton, Alberta. Of the 62 brine samples collected, 47 were collected from the Leduc Formation. Other samples included brine from: Mississippian (one sample from Banff), Triassic (11 samples from Montney, Spray River and undefined), Jurassic (one sample from Nordegg) and Cretaceous (two samples from Wapiabi, Gething) strata.

The analytical results showed that the Devonian Leduc Formation aquifer contains brine that is significantly enriched in lithium in comparison to the Triassic to Cretaceous brine (Figure 6.6). LEXG reported that 47 Leduc Formation brine samples from the Sturgeon Lake Oilfield contained between 55.4 mg/L Li and 83.7 mg/L Li with an average Leduc Formation aquifer brine lithium content of 67 mg/L Li (Dufresne and Eccles, 2013; Eccles, 2018). Additional dataset detail is presented in Section 10, Drilling.

6.3.2 2016 MGX Brine Sampling Program

In 2016, a Li-brine assay program conducted by MGX collected Leduc Formation aquifer brine samples from the Sturgeon Lake Oilfield. A total of 13 assay samples were collected from wells in the Sturgeon Lake South Oilfield, the Sturgeon Lake North Oilfield, and from the main water dispersal line at the Sturgeon Lake South Gas Plant. All samples were analyzed at Bureau Veritas in Edmonton, AB.

A summary of the analytical results of the 2016 brine assay sampling program is presented in Table 6.1 and Figure 6.6. Except for RE16-MGX-SL004 (well 00/05-15-069-22W5), the results of the brine assays show a homogeneous concentration of lithium and confirm the presence of Li-bearing brine in the Leduc Formation aquifer underlying the Boardwalk Property. The average lithium value for the 2016 brine samples is 59.3 mg/L for all samples, and 61.5 mg/L when sample RE16-MGX-SL004 is omitted (Eccles, 2018). The author suggested omitting the results of brine from sample RE16-MGX-SL004 (well 00/05-15-069-22W5; 35.6 mg/L Li) because the well is located adjacent to a competitor's 'Class 1 Disposal Well'. Hence the aquifer brine at this location, and the resulting brine sample, could include localized contamination from the Class 1 Disposal Well.

Samples taken from the Sturgeon Lake Gas Plant (n=4) are highlighted in blue in Figure 6.7 and show similar lithium values in comparison to those from the individual wells on the Boardwalk Property. The average lithium value for samples of individual wells is 58.7 mg/L while the average Li value for the samples taken at the Sturgeon Lake Gas Plant is 60.5 mg/L with a relative standard deviation (RSD) of 0.44% (Eccles, 2018). Note: the RSD% is a measure of the precision and reproducibility of the analytical results, values of <10% are considered to show good precision and reproducibility).

The similarity in the lithium content of brine in the individual wells versus those at the Sturgeon Lake Gas Plant is an important observation because the Sturgeon Lake Gas Plant collects Leduc Formation brine from throughout the Property, and therefore, represents the main brine collection site on the southern portion of the Boardwalk Property (i.e., if the Li-brine opportunity at the Boardwalk Property ever reaches an economic feasibility stage, the Sturgeon Lake Gas Plant would represent a logical pilot testing plant site).

MGX Minerals Ltd. (2016 analytical results)

Sample ID	UWI	Sample type	Lithium (mg/L)	Bromide (mg/L)	Potassium (mg/L)	Boron (mg/L)
RE16-MGX-SL001	00/08-34-068-22W5	Original	60.7	330.0	4,230.0	106.0
RE16-MGX-SL002	02-02-069-22W5	Original	60.3	400.0	4,330.0	109.0
RE16-MGX-SL003	02-02-069-22W5	Dup1	60.2	380.0	4,330.0	110.0
RE16-MGX-SL004	00/05-15-069-22W5	Original	35.6	240.0	2,830.0	67.0
RE16-MGX-SL005	02/07-19-069-22W5	Original	64.3	400.0	4,670.0	113.0
RE16-MGX-SL006	02/07-19-069-22W5	Duplicate	64.7	390.0	4,690.0	113.0
RE16-MGX-SL007	Control Blank	Control blank	0.0	0.0	1.1	0.0
RE16-MGX-SL008	02-02-069-22W5	Dup2	60.5	280.0	4,350.0	110.0
RE16-MGX-SL009	02/16-29-071-23W5	Original	60.5	380.0	4,600.0	109.0
RE16-MGX-SL010	02/16-29-071-23W5	Duplicate	60.9	350.0	4,640.0	109.0
RE16-MGX-SL011	02/08-06-072-23W5	Original	61.9	370.0	4,730.0	108.0
RE16-MGX-SL012	02/06-21-071-23W5	Original	61.2	310.0	4,620.0	109.0
RE16-MGX-SL013	02-02-069-22W5	Dup3	60.8	390.0	4,630.0	110.0
		Min	**35.6**	**240.0**	**2,830.0**	**67.0**
		Max	**64.7**	**400.0**	**4,730.0**	**113.0**
		Avg	**59.3**	**351.7**	**4,387.5**	**106.1**
		Avg (without 05-15 data)	**61.5**	**361.8**	**4,529.1**	**109.6**
		Mini-bulk sample average	60.5	362.5	4410.0	109.8
		Mini-bulk sample RSD%	0.44	15.34	3.33	0.46
		SRC analytical results (2017)	71	334	4212	/

Figure 6.7: Summary of analytical results from MGX Minerals Inc. 2016 brine sampling program at the Sturgeon Lake Oilfield. Samples collected from the Sturgeon Lake South Gas Plant are highlighted. Source: Eccles (2018)

7. Geological Setting and Mineralization

7.1 Regional Geology

The regional stratigraphy of west-central Alberta and the Western Canada Sedimentary Basin (WCSB) is summarized in Figure 7.1. The geology of the Precambrian bedrock and Phanerozoic units underlying the Boardwalk Property is summarized in Figure 7.2 and Figure 7.3, respectively, and discussed in the text that follows.

7.2 Precambrian Geology

The Boardwalk Property lies near the centre of the WCSB south of the Peace River Arch (PRA). The property lies mostly on the Chinchaga Terrane (Figure 7.2), with the northwest corner of the property on the Ksituan Magmatic Arc (Panǎ, 2003). The Chinchaga Terrane is part of the Buffalo Head craton which is thought to have accreted to the western edge of North America between 1.8 and 2.4 billion years ago (Ross et al., 1991).

7.3 Phanerozoic Geology

Overlying the basement is a thick sequence of WCSB Phanerozoic rocks comprised mainly of Tertiary and Cretaceous sedimentary clastic rocks and Mississippian to Devonian carbonate, sandstone, and salt (e.g., Green et al., 1970; Tokarsky, 1977; Glass, 1990; Mossop and Shetson, 1994; Figure 7.3). At the base of the Beaverhill Lake Group (Figure 7.1), the Elk Point Group is comprised of restricted marine carbonate and evaporite that gradationally overlie the Watt Mountain Formation (Mossop and Shetson, 1994). The Upper Elk Point, including the Ft. Vermillion, Muskeg and Watt Mountain formations are an aquitard layer (Hitchon et al., 1990).

Overlying the Elk Point Group is carbonate of the Slave Point Formation, which was deposited on an open marine carbonate platform and forms the base for the reef complexes in the region including the Swan Hills Complex and the Peace River Arch Fringing Reef Complex. The Devonian Swan Hills Reef Complex underlies the Boardwalk Property. It is a sequence of shallowing upward reef cycles now composed of dolomite (Mossop and Shetson, 1994). The Swan Hills Complex is hydrogeologically part of the Beaverhill Lake aquifer system, which contains elevated concentrations of Li (e.g., Hitchon et al., 1995).

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, 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 Shetson, 1994). At the Boardwalk Property, the Leduc is composed of dolomite.

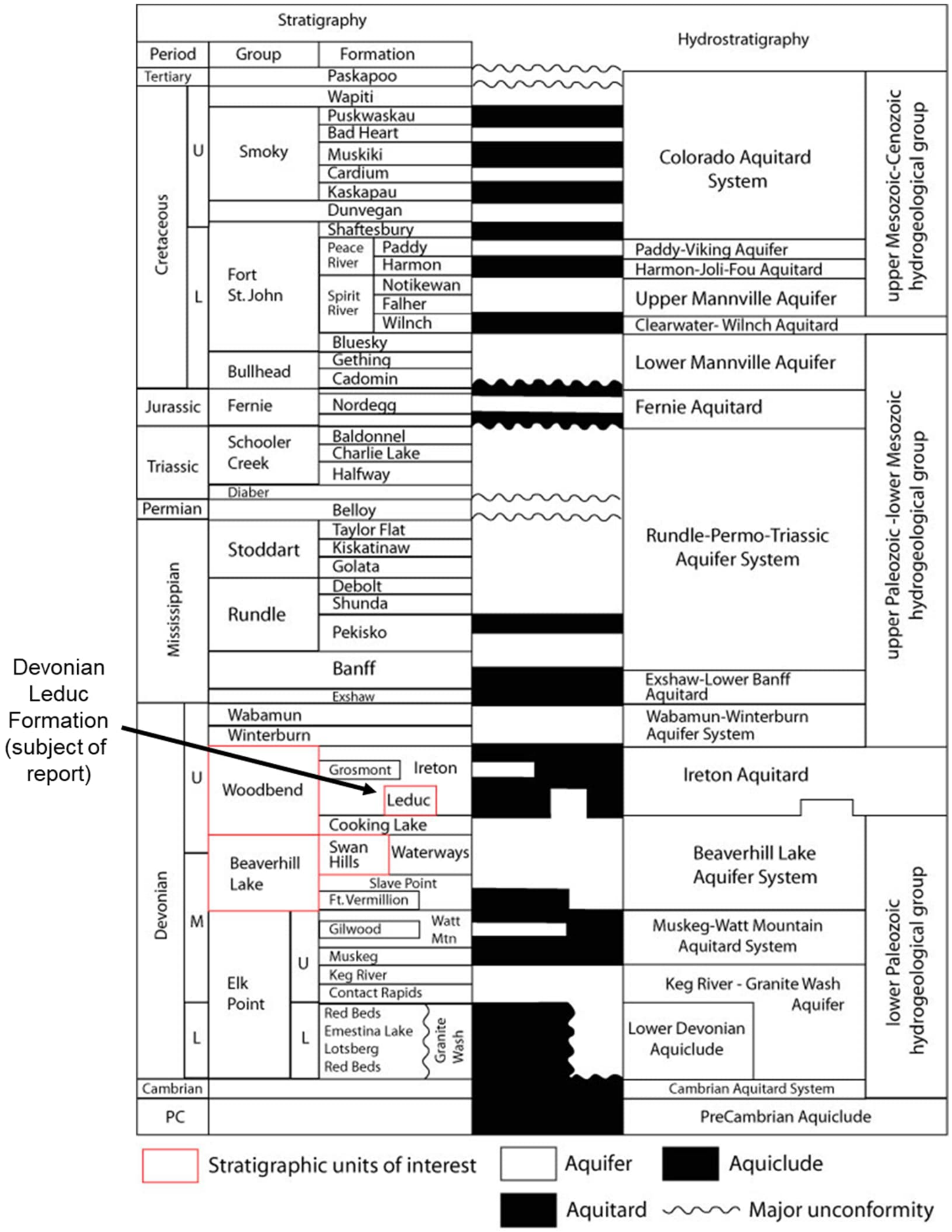


Figure 7.1: Regional Stratigraphy of the Boardwalk Property area (adapted from Hitchon et al., 1990)

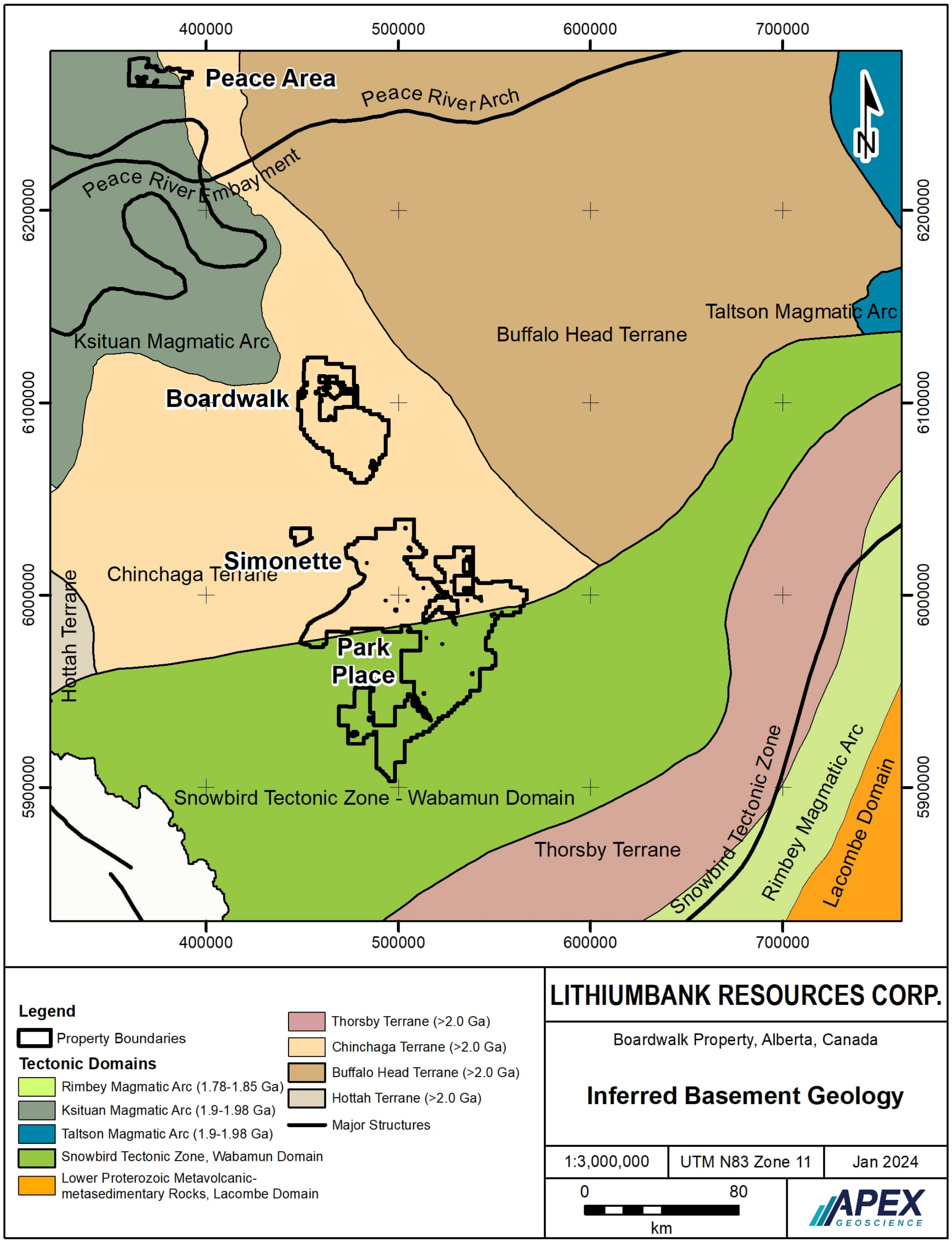


Figure 7.2: Inferred basement geology of the Boardwalk Property area. Source: Ross et al. (1991)

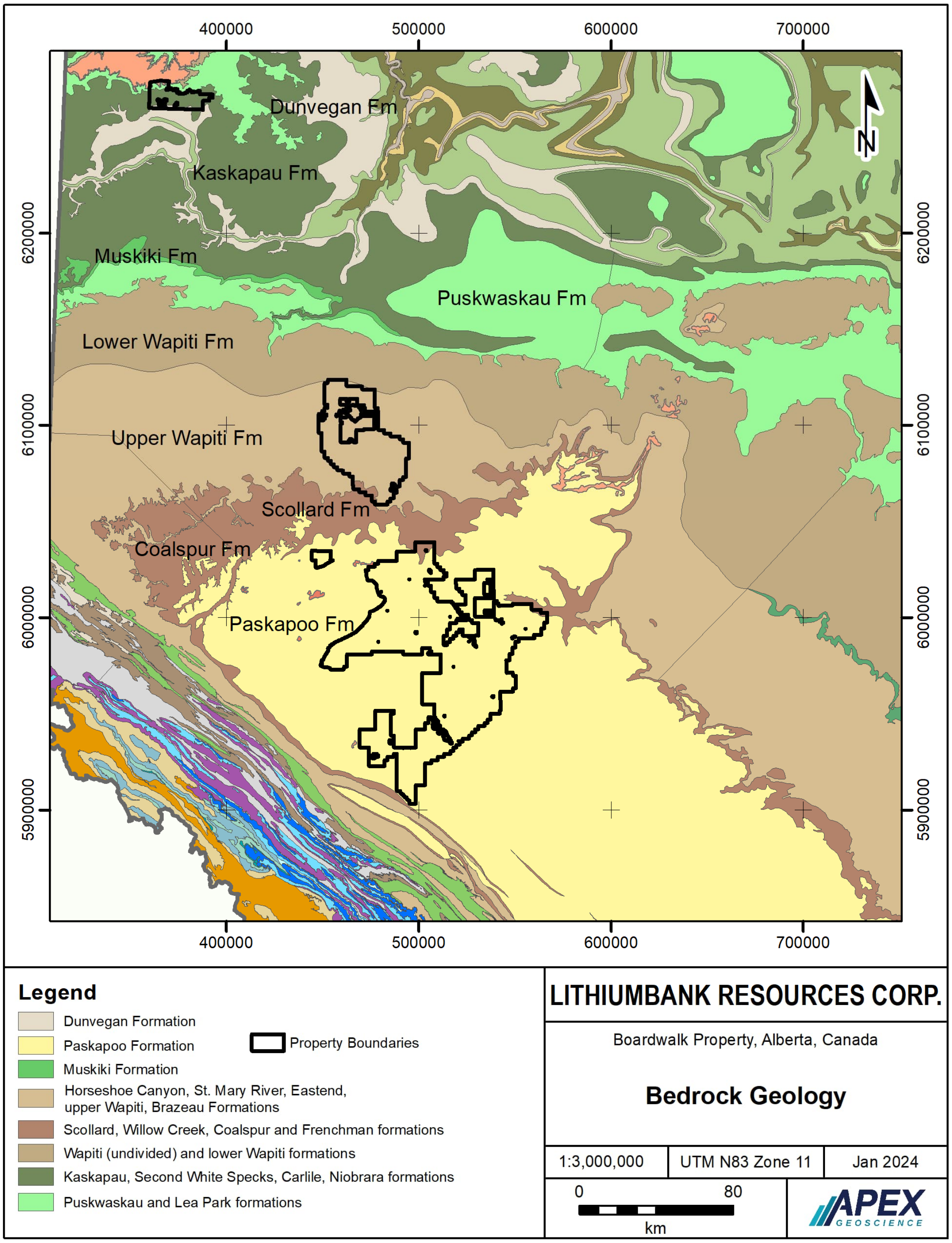


Figure 7.3: Regional bedrock geology of the Boardwalk Property area. Source: Prior et al. (2013)

The Leduc Formation (Woodbend Group) is host to prolific reserves of oil and gas in Alberta and contains elevated concentrations of lithium (e.g., 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 Shetson, 1994). The Ireton Formation is an aquitard that forms an impermeable cap rock over the Leduc reefs (Hitchon et al., 1995).

The Woodbend Group is conformably overlain by the Winterburn and Wabamun Groups of upper Devonian age (Figure 7.1). In the area of the property the Winterburn thickness in north-central Alberta is available from the logs of holes drilled for petroleum Group is composed of shale and argillaceous limestone. The Wabamun Group is composed of massive buff to brown 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 siliciclastic, marlstone and dolostone overlying a basal shale, siltstone, and sandstone unit (Mossop and Shetson, 1994). The Rundle Group conformably overlies the Banff Group. and is composed of cyclic dolostone and limestone with subordinate shale. Permian strata at the Property are very 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 Shetson, 1994).

The overlying Mesozoic strata (mainly Cretaceous) are composed of alternating units of marine and nonmarine sandstone, shale, siltstone, mudstone, and bentonite. The Triassic is characterized by fine-grained argillaceous siltstone and sandstone.

7.4 Late Tertiary – Quaternary Geology

During the Pleistocene, multiple southerly glacial advances of the Laurentide Ice Sheet across the region resulted in the deposition of ground moraine and associated sediments in north-central Alberta. The glacial ice is believed to have receded from the area between 15,000 and 10,000 years ago (Dyke and Prest, 1987). The majority of the Boardwalk Property is covered by drift of variable thickness, ranging from a discontinuous veneer to just over 15 m (Pawlowicz and Fenton, 1995a, b).

7.5 Structural Geology

In northern Alberta, the PRA is a region where the younger Phanerozoic and Cenozoic rocks, which overlie the Precambrian basement, have undergone periodic vertical and, possibly, compressive deformation from the Proterozoic into Tertiary time (e.g., Cant, 1988; O'Connell et al., 1990). This pattern of long-lived, periodic uplift and subsidence has imposed a structural control on the deposition patterns of the Phanerozoic, and to a lesser extent the

Cenozoic, strata in northern and north central Alberta. In addition, this periodic movement has resulted in a rectilinear pattern of faults that is responsible for the structurally controlled reefs along with oil and gas pools found throughout this area.

During the Devonian, the PRA was emergent and was a positive paleo-topographic relief feature oriented east-northeast from the British Columbia provincial border to at least as far east as Red Earth Creek. Toward the end of the Devonian and into the Mississippian the PRA collapsed and became the Peace River embayment. The embayment filled in during the Mississippian with a thick sequence of siliciclastic rocks along with dolostone and limestone.

Several prominent Alberta Devonian Reef complexes are underlain by and proximal to basement faults and that these reef complexes promoted growth over long periods of time at fault interfaces along the shallow water side or uplifted block edge of these faults during slow subsidence of the downside of the fault (e.g., Bloy and Hadley, 1989; Dufresne et al., 1996). At the Sturgeon Lake Reef Complex, individual reef cycles reveal significant fault offset of the reservoir throughout the entire complex (Stoakes and Campbell, 1996).

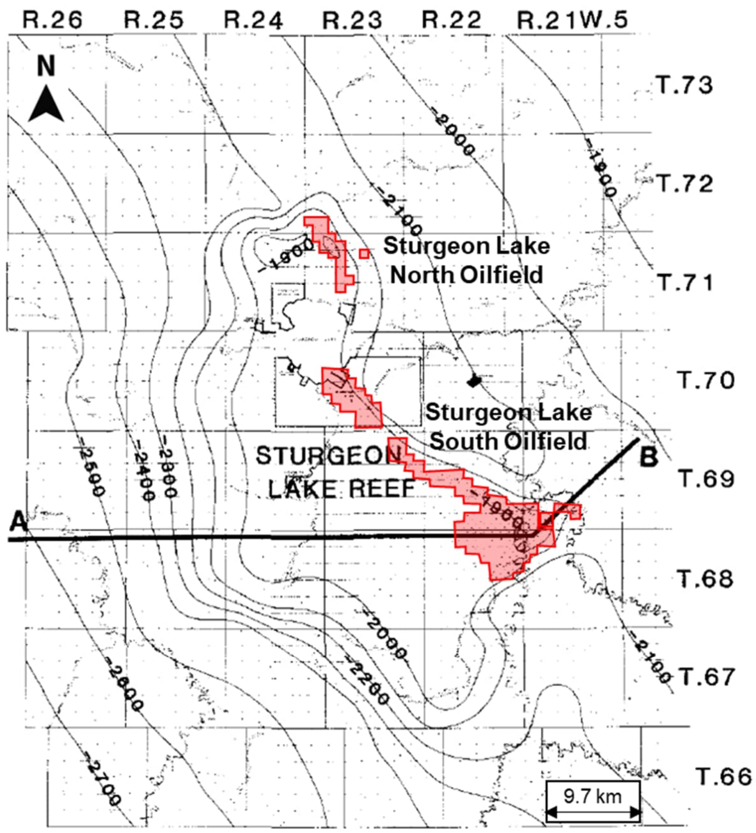
7.6 Property Geology: Introduction to the Woodbend Group (Leduc Formation) Aquifer System

The geological focus of this Technical Report is on the aquifer system within the Late Devonian (Frasnian) dolomitized reef structure of the Woodbend Group, Leduc Formation, that conformably overlies the carbonates of the Beaverhill Lake Group. The reef structure is called the Sturgeon Lake Reef Complex, and the LithiumBank Property encompasses most of the complex.

The approximately 1,000 km^2 Sturgeon Lake Reef Complex is centered over Township 69 Range 23W5M (Figure 7.4). Hydrocarbons are stratigraphically trapped in the dolomitized Leduc Formation at a depth of approximately -2,500 m below surface by the enclosing shales of the Ireton Formation (Anderson et al., 1989). Two predominant oil and gas fields occur along the irregular up-dip (eastern) edge of the reef complex and include the Sturgeon Lake North and Sturgeon Lake South Oilfields (Figure 7.4b). Differential compaction between back-reef lagoonal carbonate, off-reef shale and the more rigid, dolomitized periphery of the reef build-up has given the complex a broadly atoll-like shape (Figure 7.4b).

At the Boardwalk Property, the top of the Beaverhill Lake Group ranges from approximately -1,900 m above sea level (m asl) in the northeastern to -2,750 m asl in the southwestern corner of the Property. The Beaverhill Lake Group has an average dip to the southwest at approximately 0.011 (11 m/km).

A) Contour map of the top of the Leduc Formation (in metres relative to sea level) with the outline of the Sturgeon Lake North and South oilfields.



B) Profile A-B across the Sturgeon Lake Reed Complex (approximately 60 km across).

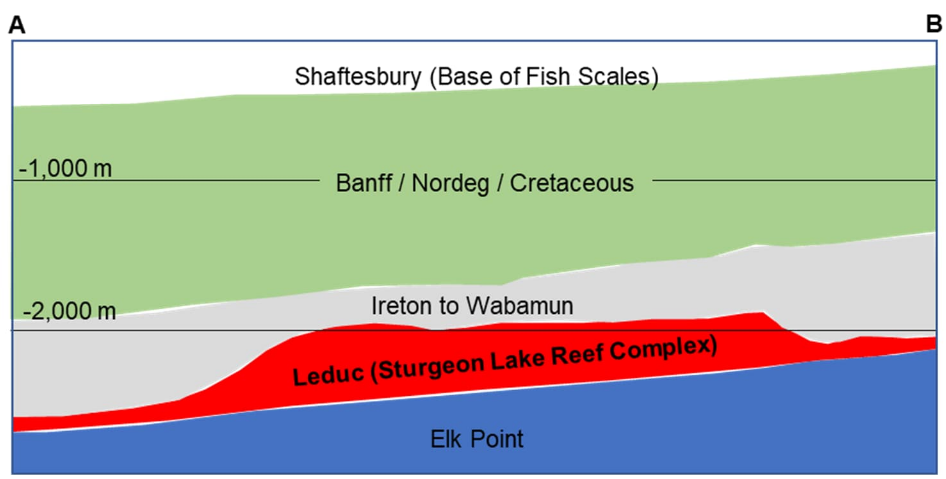


Figure 7.4: Lateral and vertical extent of the Sturgeon Lake Reef Complex. Source: Anderson et al. (1989)

The Leduc Formation is defined by subsurface oil and gas exploration (n=242 wells) that define the true vertical depth of the Leduc Formation at depths of between -2,337.6 m and -3,050.6 m (average -2,619.9 m) below the Earth's surface. The Leduc reef has a thickness of approximately 230 to 380 m (average and maximum thicknesses of 206 m and 408 m) along a southwest to northeast cross section at the Boardwalk Property (Hydrogeological Consultants Ltd., 2012).

The Beaverhill Lake Group (Swan Hills aquifer) and the Woodbend Group (Leduc aquifer) were thought to be hydraulically connected due to historical government interpretation of Hitchon et al. (1995). A hydrological assessment conducted by HCL has demonstrated the two units – at least in LithiumBank's Boardwalk Property area – are in fact not connected.

The brine is hypersaline. Reported total dissolved solids (TDS) concentrations of 77 Leduc samples ranged from 113,117 to 265,921 mg/L, with an average of 199,995 mg/L (Hydrogeological Consultants Ltd., 2012). By comparison, Hitchon et al (1995), who culled the brine geochemical dataset based on anion-cation balance, reported the results of 7 brine samples from the Leduc Formation that contained a lithium concentration of >100 mg/L; these 7 samples had an average TDS concentration of 214,611 mg/L.

A study of the hydrogeological characteristics of the Leduc Formation aquifer at the Boardwalk Property is presented in Section 14.3.

7.7 Summary of Reservoir Study of the Sturgeon Lake South and North Oilfields

A 1989-1990 geological study of the Sturgeon Lake Reef Complex was undertaken by Stoakes (1990) to develop geological models of the Sturgeon Lake South and North Oilfields. The database comprised 350 wells and 103 Leduc Formation cores. The cores were examined to ascertain lithology, fauna, facies, and the nature and distribution of porosity. The core assessment was correlated with the well petrophysical e-logs such that the geological interpretations could be extrapolated to the un-cored sections.

Select conclusions of the Stoakes (1990) study are included as follows:

- Within the upper 100 m of the reef complex, five major cycles were identified, in ascending order A, A2, B, C, and D (Figure 7.4). The cycles are separated by deeper water events and an average maximum of 15-20 m per cycle.
- While a variety of diagenetic processes influence the reef complex, dolomitization is the most significant enhancer of porosity and was systematically mapped as being initiated on the periphery or the reef and penetrated only partially into the reef buildup.
- The eastern sections of the Sturgeon Lake Oilfields consist mainly of cycles A, A2, and B, which highly dolomitized. In contrast, cycles C and D are more prevalent on the western side of the oilfields and have lower porosity.
- Two sets of faults were identified, 1) major northeast-southwest orientated fault, and 2) subsidiary faults running perpendicular to the major faults. The faults were interpreted as

normal faults. Several upthrown blocks were delineated on the southern and eastern flanks of the Sturgeon Lake South Oilfield. The Sturgeon Lake North Oilfield is fault-divided into a series of discrete blocks.

- Nine different depositional facies were recognized in the Sturgeon Lake Reef Complex and encompass basinal to margin to lagoonal sedimentary rocks. Each facies have discrete depositional textures, colour, biota, sedimentary and biogenic structures, and estimates of average porosity as presented in Figure 7.5.

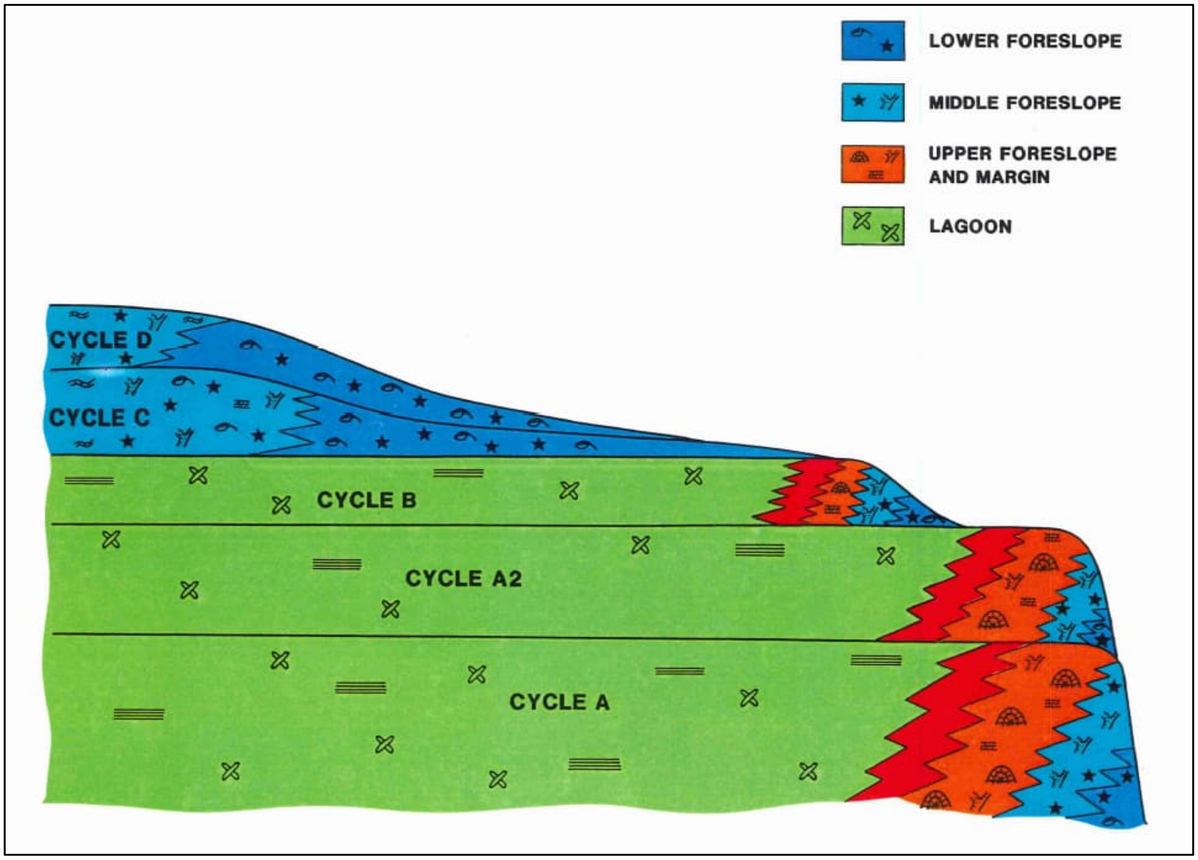
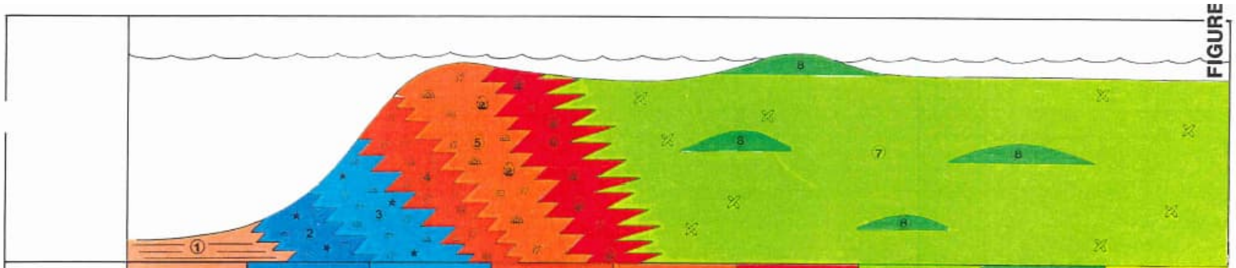


Figure 7.5: Schematic sketch of major cycles within the Sturgeon Lake South and North Oilfields. Source: Stoakes (1990)



FACIES NO.	①	2	3	4	5	6	7	8	9
FACIES	STARVED BASIN	LOWER FORESLOPE	MIDDLE FORESLOPE	UPPER FORESLOPE	REEF CREST	REEF FLAT	LAGOON	TIDAL FLAT	FORESLOPE GRAINSTONE
DEPOSITIONAL TEXTURE	MUDSTONE	WACKESTONE TO FLOATSTONE MUDSTONE MATRIX	FLOATSTONE PACKSTONE TO WACKESTONE MATRIX	FLOATSTONE GRAINSTONE MATRIX ALLOCHTHONOUS DEBRIS	FLOATSTONE RUDSTONE AND BOUNDSTONE GRAINSTONE MATRIX	GRAINSTONE TO FLOATSTONE	FLOATSTONE TO RUDSTONE MUDSTONE TO GRAINSTONE MATRIX	MUDSTONE	GRAINSTONE CAN OCCUR MIXED WITH FACIES 2-4
COLOUR	DARK BROWN OR BLACK	DARK BROWN	BROWN TO DARK BROWN	LIGHT BROWN	LIGHT BROWN	LIGHT BROWN	DARK TO LIGHT	DARK TO LIGHT	LIGHT BROWN
BIOTA – DOMINANT		CRINOIDS BRACHIOPODS	TABULAR STROM. THAMNOPOROID CORALS	MASSIVE, TABULAR AND CYLINDRICAL STROM. THAMN. CORALS	MASSIVE TABULAR AND CYLINDRICAL STROM. THAMN. CORALS	BULBOUS STROM.	AMPHIPORA	—	—
BIOTA – SECONDARY	LOCAL NERITIC LIFE	THAMNOPOROID CORALS WAFER STROM.	CRINOIDS BRACHIOPODS			CYLINDRICAL STROM. THAMN. CORALS AMPHIPORA	BULBOUS STROM. THAMN. CORALS GASTROPODS	—	—
SEDIMENTARY AND BIOGENIC STRUCTURES	PLANAR LAMINATIONS NODULAR TEXTURE DISCRETE BURROWS HARDGROUNDS	BIOTURBATED	MASSIVE TO BEDDED	MASSIVE TO BEDDED	MASSIVE	BEDDED	BEDDED	LAMINATED	MASSIVE TO BEDDED
AVG. POROSITY	0.30	1.96	5.04	5.45	5.70	5.05	4.84	2.58	5.76

Figure 7.6: Facies summary at the Sturgeon Lake South and North Oilfields. Source: Stoakes (1990)

7.8 Mineralization

Lithium mineralization within the Devonian Leduc Formation aquifer is in solution within the brine; hence it is not observed in the physical state. Accordingly, the best way to provide discussion on mineralization is to review the geochemical nature of the brine.

The author has compiled Government and industry brine sampling that conducted from oil and gas wells within the Sturgeon Lake Oilfield. Using the bivariate plot of Li vs K/Br in Figure 7.6, the results show the anomalous nature of the Devonian Leduc Formation brine in comparison to brine that was collected from pre-Devonian (Mississippian to Cretaceous) aquifers. The pre-Devonian brine from the Sturgeon Lake Oilfield has <42 mg/L Li and a K/Br ratio of <8.2. In contrast, the Devonian Leduc Formation brine has 56-84 mg/L Li and K/Br ratios of 9.1 to 15.6.

The average crustal abundance of lithium is approximately 17-20 ppm with higher abundances in igneous (28-30 ppm) and sedimentary rocks (53-60 ppm; Evans, 2014; Kunasz, 2006). Hence, the elevated lithium content in Devonian brines in the Alberta basin portion of the Western Canada Sedimentary Basin define the mineralization being discussed in this technical report.

The elevated K/Br, in conjunction with high Li/Br and increasingly radiogenic $^{87}Sr/^{86}Sr$ values indicate an influence of a hydrothermal fluid(s) and/or mobilization of silicate-bearing fluids from either the crystalline basement or the immature siliciclastic deposited above the basement (basal Cambrian sandstone, Granite Wash or the Gilwood Member), to the Devonian brine (Eccles and Berhane, 2011; Huff, 2019). A cluster of Leduc Formation brine analyses has low K/Br (<1.5) and possible that the Li-enriched brine formed in another environment perhaps through dissolution of Li-bearing late-stage evaporite minerals into mid-Devonian seawater evapo-concentrated to, but not beyond, halite saturation (Huff, 2019).

Other geochemical attributes of the Leduc Formation aquifer brine – as collected by the QP at the Boardwalk Property – are presented in Figure 7.7 and Figure 7.8. Additional Leduc Formation brine attributes include a relative density of 1.214 g/cm^3, observed pH of 7.10, measured TDS of 246,700 mg/L, conductivity of 214,000 uS/cm and total alkalinity as $CaCO_3$ of 290 mg/L. The analytical charge imbalance is -1.52%. The calculated charge imbalance, using the brine density and TDS is -1.68%.

The QP-analyzed brine results correlate well with a review of historically documented Leduc Formation fluid-quality data accessed from AccuMap (n=77 analyses). These data record TDS concentrations of between 110,700 and 278,554 mg/L TDS, with an average TDS concentration of 214,683 mg/L.

The major ions are classified as having predominantly sodium and calcium cations and predominantly chloride anions (Figure 7.7 and Figure 7.9). The average formation temperature in the DST results analyzed by Melange was 82°C.

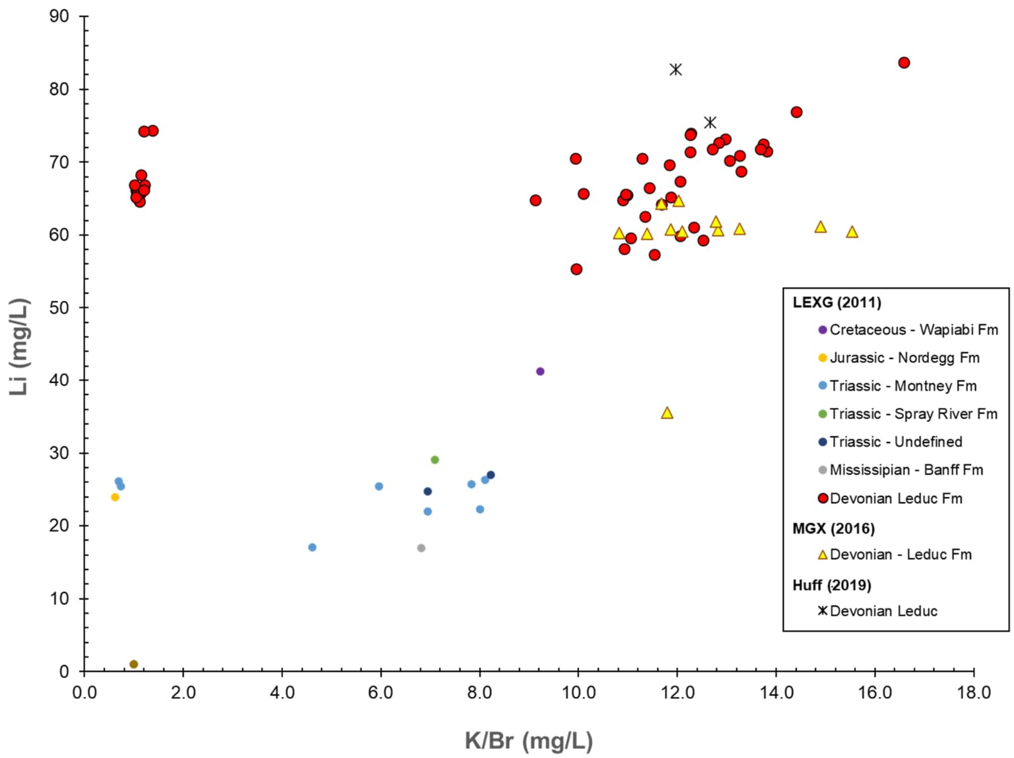


Figure 7.7: Plot of lithium versus potassium/bromide to show the anomalous geochemical nature of the Devonian Leduc Formation brine in comparison to pre-Devonian brine from the Sturgeon Lake Oilfield

Cation	(meq)	(mg/l)	Anion	(meq)	(mg/l)
Li	11.5326	60.3	Cl	5713.91	152600
Na	3458.76	59900	Br	6.64577	400
K	147.001	4330	I	0.282445	27
Mg	300.313	2750	SO4	9.397	340
Ca	1616.31	24400	B	-	109
Sr	32.1192	1060	Se	-	0.44
Ba	0.206847	10.7	HCO3	7.61464	350
Ag	5.17E-03	0.42			
Mn	9.57E-03	0.198			
Fe	6.18E-03	0.13			
Pb	2.56E-03	0.2			

Figure 7.8: Leduc brine chemistry from the Sturgeon Lake Oilfield (sample RE16-SL-002)

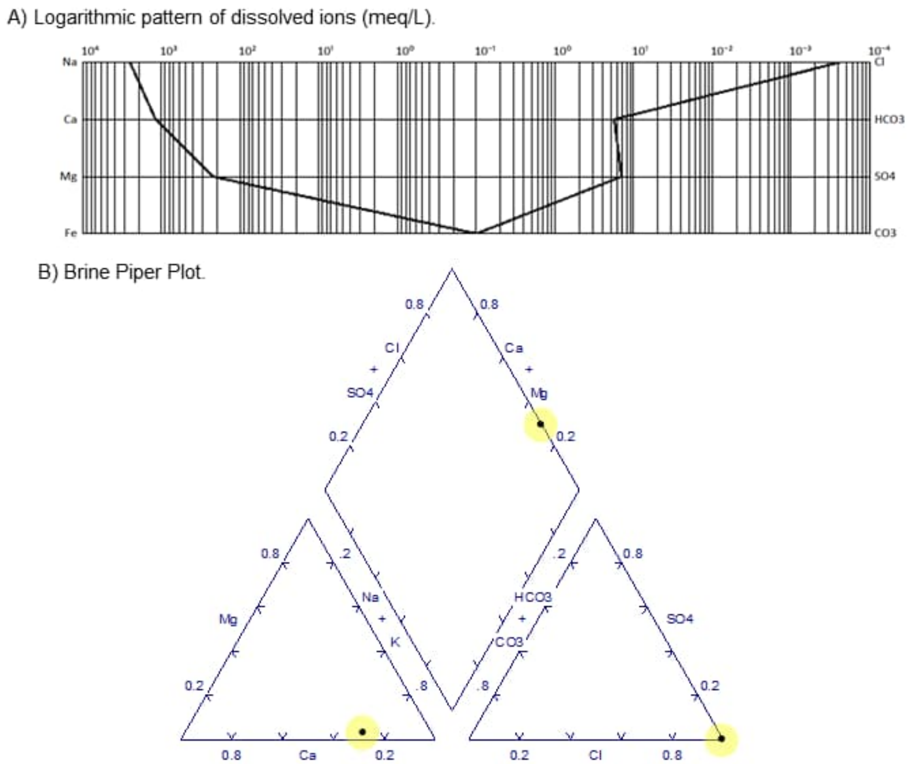


Figure 7.9: Leduc brine chemistry from the Sturgeon Lake Oilfield (sample RE16-SL-002)

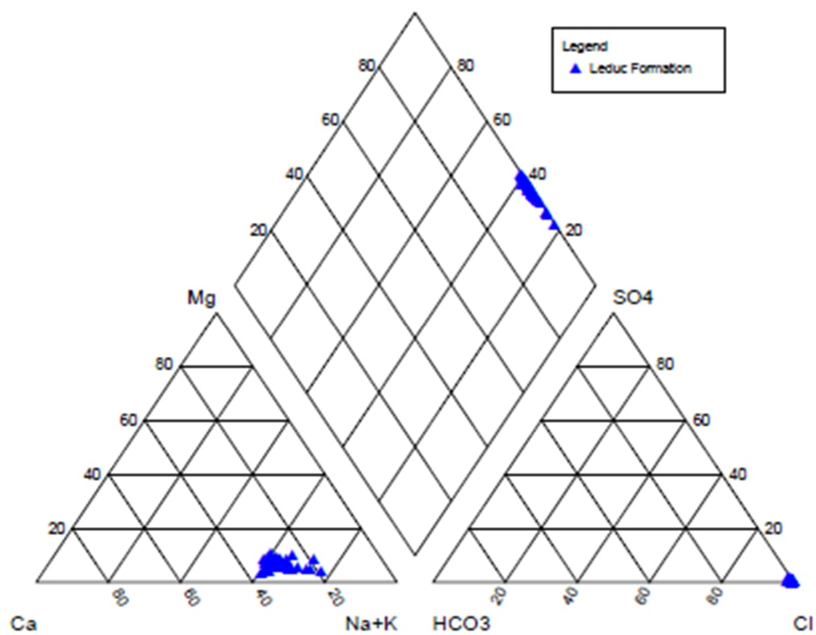


Figure 7.10: Assessment of Leduc Formation water quality at the Boardwalk Property

8. Deposit Types

There are over 100 minerals that contain lithium, but only a few of these are currently economic to extract. Lithium is extracted from two main categories of deposits: mineral and brine. With respect to mineral deposits, lithium is extracted primarily from pegmatite deposits. Pegmatite lithium deposits are found globally and account for half of the lithium produced today (Benson et al., 2017). Spodumene is the most abundant lithium-bearing mineral found in economic deposits.

Brine deposits can be separated into 1) surface or near-subsurface continental deposits (salars), and 2) confined aquifer deposits that occur in deep, subsurface basial aquifers. Continental brine occurs in endorheic basins where inflowing surface and groundwater is moderately enriched in lithium. All currently producing lithium brine operations are represented by continental brine deposits.

Economic continental brine aquifers typically occur in areas where high solar evaporation results in beneficiating the brine to higher concentrations of lithium. Geothermal and/or volcanic associations are the favoured mechanisms for introducing lithium into continental basins because lithium-rich brines often exist in areas of volcanic activity (e.g., Imperial Valley, California; Reykjanes field, Iceland; Taupo Volcanic Zone, New Zealand). Typical lithium concentrations in commercially developed continental brine deposits are 200 to 1,500 mg/L.

Selected continental brine deposit examples include: Salar de Uyuni in Bolivia Salar de Atacama in Chile, Salar de Hombre Muerto in Argentina; Salar del Rincon and the Salar del Olaroz in Argentina, and the Zhabuye Salt Lake in the Tibetan Plateau, the DXC Salt Lake, and the Qaidam Basin in China (e.g., Shengsong, 1986; Garrett, 2004; Pavlovic and Fowler, 2004; Bradley et al., 2017; Zheng et al., 2007).

Confined aquifer brine deposits occur in sedimentary basins occur at typical depths of >2,000 m beneath the Earth's surface in deep-seated, near-basement, pressurized aquifers. The lithium is derived from either the crystalline basement or the immature siliciclastic material deposited above the basement, to deep-seated aquifers situated directly above, or proximal to, the underlying basement, and/or were formed through halite dissolution and mixing with Li-enriched fluids possibly expelled from Precambrian crystalline basement rocks via hydrothermal fluids (Eccles and Berhane, 2011; Huff, 2019). The aquifers are typically confined in that the aquifer is bound by aquitards, but in some instances, several aquifers can commingle within a larger confined aquifer system. As such the mobilization and accommodation of lithium-enriched brine can occur in different aquifer settings that could include, for example, pervasively altered and fractured basement, granite wash sediments, near-basement sandstone horizons, and fault induced reef complexes (Figure 8.1; Eccles et al., 2011; Eccles, 2012).

Lithium enrichment of deep saline to hypersaline brine is known to occur worldwide in sedimentary basins of various age, including: the Cambrian Siberian Platform, Russia, Devonian Michigan Basin; Mississippian–Pennsylvanian reservoirs of the Illinois Basin; Pennsylvanian Paradox Basin, Utah, Triassic strata of the Paris Basin, France, Jurassic Smackover strata from the Gulf Coast, Arkansas, and Texas, and Permo-Triassic Rotliegend-Buntsandstein strata in the Upper Rhine Valley, Germany (e.g., Moldovanyi and Walter, 1992; Stueber et al., 1993; Wilson and Long, 1993; Fontes and Matray, 1993; Garrett, 2004; Shouakar-Stash et al., 2007; Eccles et al., 2018, 2020).

The deep confined aquifer brine can be accessed through agreements with Petro-or geothermal-operators that pump the brine to surface as a wastewater product of hydrocarbon production or as part of the geothermal brine circuit. Additionally, the Li-brine company can drill their own production wells.

Geological concepts being applied in the investigation and/or exploration of deep-seated, confined Li-brine deposits include a compilation and review of historical oil and gas, or geothermal, geochemical fluid data, and target selection of deep-seated, porous, large-scale aquifers. Conventional brine assays are then accomplished by collecting brine from sample points with the existing oil and gas, or geothermal, infrastructure (e.g., wellhead, separator unit, pipelines, and reinjection points).

In addition to assay samples to assess the lithium content of the brine, mini-bulk brine samples are collected to define mineral processing methods that can recover lithium from the brine using a quicker extraction technology. Brine sample quantities of 10's liters to 1,000's litres are applicable in bench-scale test work prior to expanding the operation to the pilot plant, and potential commercial application stage.

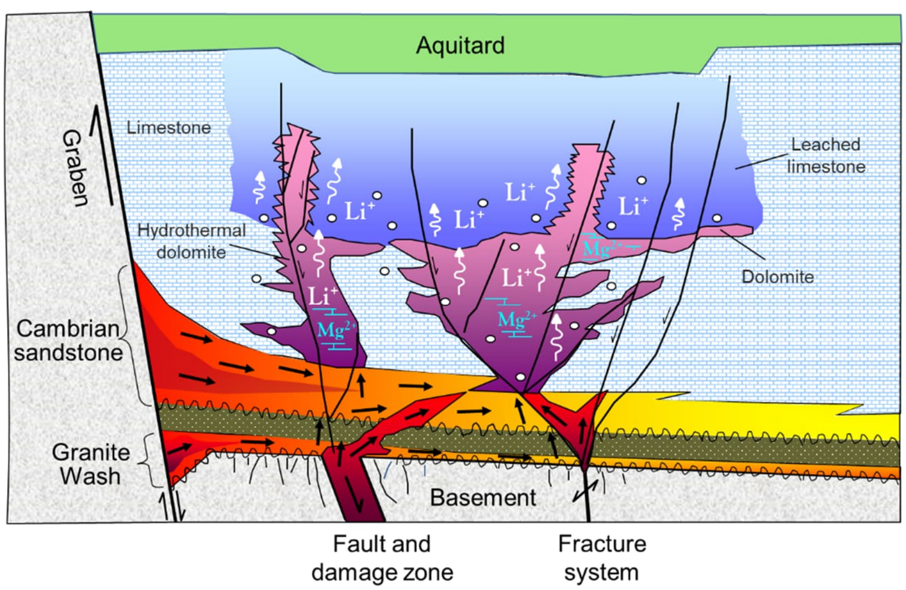


Figure 8.1: Schematic geological model to illustrate a theory on how lithium might be derived from crystalline basement, basement fault zones, and/or immature siliciclastic material

9. Exploration

9.1 LithiumBank 2021 Brine Assay Sample Program

Through a brine access agreement ratified between LithiumBank and a Petro-company operating in the North and South Sturgeon Lake Oilfields, four suspended oil and gas wells within the Boardwalk Property and Sturgeon Lake South Oilfield were swabbed out for the sole purpose of collecting representative Leduc Formation aquifer brine for LithiumBank's assay testing and mineral processing test work. The wells included: CNRL STURLKS 9-26-68-22, CNRL STURLKS 13-27-68-22, BARRICK STURLKS 10-6-69-21, and CNRL STURLKS 7-25-68-22 (Figure 9.1; Figure 9.2 and Figure 9.3).

The well reopening work and brine sampling program took place between July 27, 2021, and August 13, 2021. The Petro-company managed the well reopening work, including contractors and logistics such mechanical work, well swabbing, brine flow and collection, safety, and once the brine was collected, re-fixing the well back into a suspended well status. On-site contractors, as managed by the Petro-company, were based out of Grande Prairie, AB, and included Quinn Well Control Inc. (wireline solutions) and Skyline Well Testing (skid mounted pressure tanks, flow lines, flare stacks, etc.).

As part of the brine sampling program, LithiumBank commissioned 1) APEX, and specifically the QP, to conduct a QP site inspection and oversee brine collection at well CNRL STURLKS 9-26-68-22; 2) AGAT Laboratories (Grande Prairie, AB office) to safely collect the H_2S-laden brine assay samples; and 3) AMGAS Services Inc. (AMGAS) to haul bulk mineral processing brine samples to their facility in Beaverlodge, AB where the brine was mitigated of H_2S from its sour to a sweetened state.

To ensure the brine was representative of the Leduc Formation aquifer, the recovery process accounted for the removal of non-representative, 'waste' fluid from the well head to the depth of the Leduc reservoir. To do this, the Petro-company calculated for the removal of approximately 12 m^3 of waste fluid, which is roughly equivalent to 1.5 times the volume of the tubing. The waste fluid was piped into a separate holding tank such that the fluid did not come into contact, or contaminate, Leduc Formation brine associated with the brine collection sampling program.

Once the waste fluid was removed, the brine was evaluated for its salinity and H_2S content. Leduc Formation brine within the Sturgeon Lake Oilfield typically has a salinity of approximately 20% to 22% and contains approximately 18-20% H_2S. Once these brine conditions were constant in the brine flow from the Leduc reservoir/aquifer to the wellhead (i.e., ensuring representative Leduc Formation brine), the brine was channeled into a separate 20 m^3 vessel for storage as part of a bulk brine sample (see Section 9.3).

Representative Leduc Formation brine samples for assay work were collected directly from a pipeline sample nipple point as the brine flowed from the wellhead to the storage vessel. The sample procedure is described in Section 11.1. A total of 44 brine samples were collected for mineral assay testing as part of LithiumBank's 2021 sampling program.

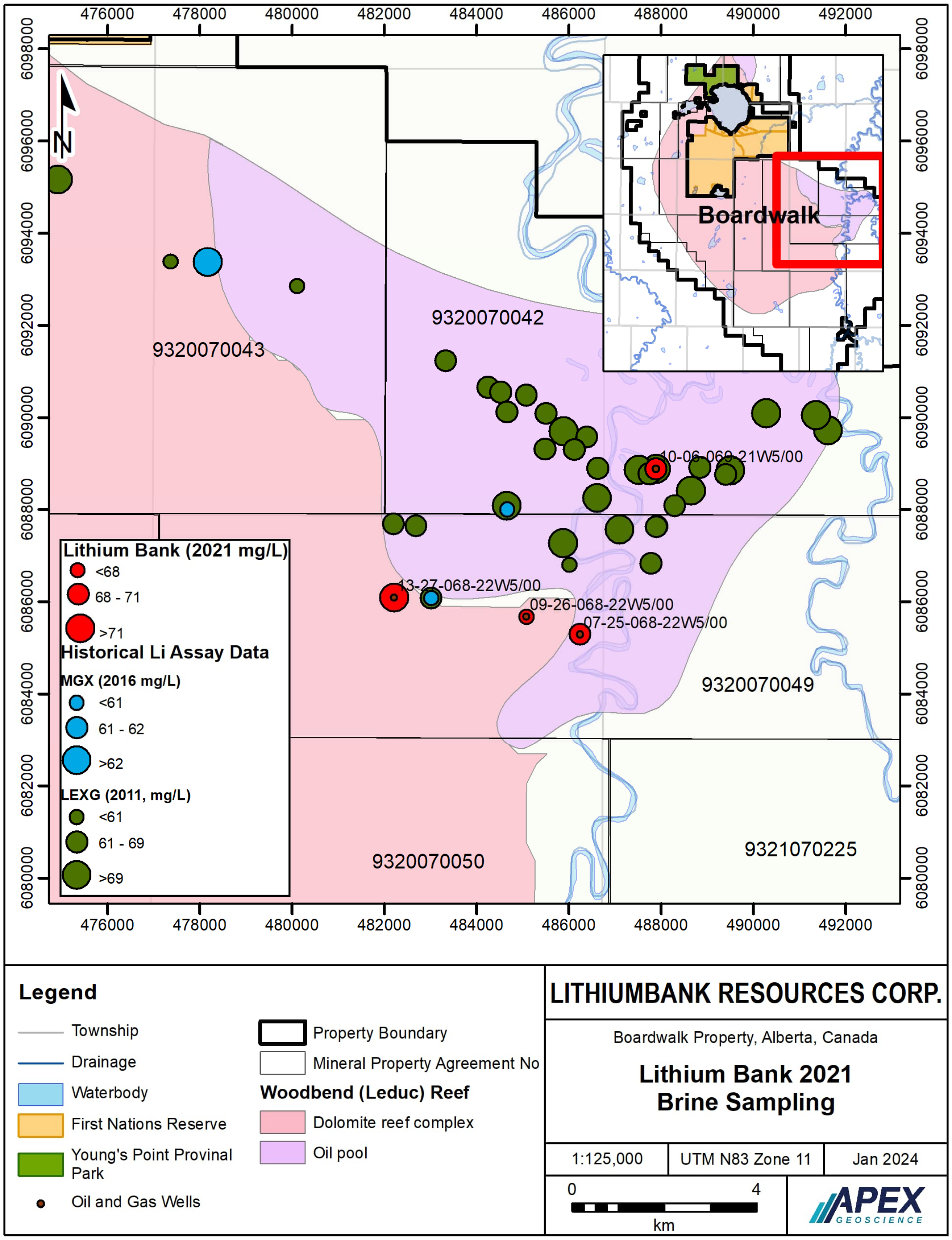


Figure 9.1: Location of oil and gas wells included in LithiumBank's Leduc Formation aquifer brine sampling program (red circles). Historical sample results are also included (blue and green circles)

Unique well ID	Well name	Latitude	Longitude	Directional drilling (well profile)	Reference (KB) elevation (m)	Total depth (m)	Well status	Field	Pool	Top of Leduc depth (m)
100/07-25-068-22W5/00	CNRL STURLKS 7-25-68-22	54.914423	-117.2146	None (vertical)	649.5	2,706.0	Suspended water disposal	Sturgeon Lake South	Leduc D-3	2,561.8
100/09-26-068-22W5/00	CNRL STURLKS 9-26-68-22	54.917755	-117.2328	None (vertical)	655.9	2687.7	Suspended water disposal	Sturgeon Lake South	Leduc undefined	2609.1
100/13-27-068-22W5/00	CNRL STURLKS 13-27-68-22	54.921378	-117.2776	None (vertical)	676	2632.6	Supended crude oil	Sturgeon Lake South	Leduc D-3	2591.4
100/10-06-069-21W5/00	BARRICK STURLKS 10-6-69-21	54.946783	-117.1891	None (vertical)	652.9	2687	Supended crude oil	Sturgeon Lake South	Leduc D-3	n/a

Figure 9.2: Summary descriptions of the oil and gas wells sampled by LithiumBank

Unique well ID	First production date	Last production date	Water production / injection years	Cumulative water production (m^3)	Cumulative water injection (m^3)	Cumulative barrel of oil equivalent production (Bbl)	Cumulative gas production (e^3m^3)	Cumulative oil production (m^3)
100/07-25-068-22W5/00	1955-08-22	1977-05-31	1961-2019	13,992	4,888,693	292,256	5,897	40,927
100/09-26-068-22W5/00	/	/	1961-2019	/	11,947,977	/	/	/
100/13-27-068-22W5/00	1956-03-13	2019-02-28	1961-2019	3,793,525	/	3,185,763	81,274	430,234
100/10-06-069-21W5/00	2005-11-01	2018-08-31	2005-2018	1,278,746	/	247,977	9,010	30,979

Figure 9.3: Historical production information of the oil and gas wells sampled by LithiumBank

Of the 44 brine assay samples, 26 samples were collected by the QP at CNRL STURLKS 9-26-68-22, and six samples were collected at each of the remaining three wells.

The reason for the additional samples at CNRL STURLKS 9-26-68-22 was because the QP implemented Quality Assurance – Quality Control (QA-QC) measures at this well as part of a site inspection of the Property.

The QA-QC sampling at CNRL STURLKS 9-26-68-22 is discussed in Section 11.3; in summary the sample collection at this well included:

- Original samples (pre-H_2S mitigation) = 6 samples.
- Duplicate samples (pre-H_2S mitigation) = 5 samples.
- Original samples (post-H_2S mitigation) = 4 samples.
- Duplicate samples (post-H_2S mitigation) = 3 samples.
- Blank standard samples, which contained no lithium = 5 samples.
- Lab-prepared semi-certified Li-brine standard samples = 3 samples.

The QP was not present for brine assay sample collection at wells CNRL STURLKS 13-27-68-22, BARRICK STURLKS 10-6-69-21, and CNRL STURLKS 7-25-68-22. In this instance, LithiumBank commissioned AGAT technicians to collect six representative samples from each well (n=18 total). The samples were collected at varying time intervals as the brine was pumped from the Leduc aquifer into the 20 m^3 holding vessel at surface.

The assay brine samples were analyzed at AGAT Laboratories in Calgary, AB, and Bureau Veritas in Edmonton, AB. Selected analytical results of the 'original', or non-QA-QC samples is presented in Figure 9.4 (n=28 analyses). In summary, the Leduc Formation aquifer brine from:

- Well CNRL STURLKS 9-26-68-22 (n=10 samples) has an average lithium concentration of 67.7 mg/L Li (ranging from 54.9 to 75.4 mg/L Li). The samples analyzed at Bureau Veritas had lower lithium content (54.9-57.2 mg/L Li) in comparison to those analyzed at AGAT (68.8-75.4 mg/L Li).
- Well CNRL STURLKS 13-27-68-22 (n=6 samples) has an average lithium concentration of 72.9 mg/L Li (ranging from 65.7 to 77.6 mg/L Li).
- Well BARRICK STURLKS 10-6-69-21 (n=6 samples) has an average lithium concentration of 69.8 mg/L Li (ranging from 65.97 to 72.3 mg/L Li).
- Well CNRL STURLKS 7-25-68-22 (n=6 samples) has an average lithium concentration of 70.9 mg/L Li (ranging from 68.8 to 71.8 mg/L Li).

A) Well CNRL STURLKS 9-26-68-22

Sample ID	Laboratory	Sample type	Sample prep (H_2S)	Total B (mg/L)	Total Li (mg/L)	Total Sr (mg/L)	Total Ca (mg/L)	Total Mg (mg/L)	Total Na (mg/L)	Total K (mg/L)	Total Organic Carbon
RE21-LB-SL-001	AGAT	Original	Un-mitigated brine	129.00	72.7	927.00	24,800.00	2,730.00	56,500.00	4,140.00	279.00
RE21-LB-SL-005	AGAT	Original	Mitigated at AmGas	126.00	71.8	939.00	25,100.00	2,680.00	57,200.00	4,160.00	166.00
RE21-LB-SL-007	Bureau Veritas	Original	Un-mitigated brine	106	57.2	1010	23500	2470	61200	4150	/
RE21-LB-SL-011	AGAT	Original	Mitigated at AmGas	126.00	75.4	963.00	24,500.00	2,780.00	58,500.00	4,370.00	/
RE21-LB-SL-014	AGAT	Original	Un-mitigated brine	130.00	72.2	905.00	23,200.00	2,690.00	54,300.00	4,180.00	/
RE21-LB-SL-016	AGAT	Original	Mitigated at AmGas	128.00	73.4	941.00	25,300.00	2,710.00	57,700.00	4,280.00	/
RE21-LB-SL-020	AGAT	Original	Un-mitigated brine	121.00	68.8	851.00	23,200.00	2,560.00	53,400.00	3,960.00	/
RE21-LB-SL-023	Bureau Veritas	Original	Un-mitigated brine	106	55.7	967	22800	2460	58700	4080	/
RE21-LB-SL-025	Bureau Veritas	Original	Un-mitigated brine	104	54.9	957	21900	2390	56000	4020	/
RE21-LB-SL-026	AGAT	Original	Mitigated at AmGas	131.00	74.8	954.00	25,300.00	2,760.00	59,100.00	4,320.00	157.00
			Min	104.00	54.90	851.00	21,900.00	2,390.00	53,400.00	3,960.00	157.00
			Max	131.00	75.40	1,010.00	25,300.00	2,780.00	61,200.00	4,370.00	279.00
			Average	120.70	67.69	941.40	23,960.00	2,623.00	57,260.00	4,166.00	200.67
			Standard deviation	10.97	8.32	42.09	1,194.62	140.80	2,322.45	129.37	67.99
			RSD%	9.1	12.3	4.5	5.0	5.4	4.1	3.1	33.9

B) Well CNRL STURLKS 13-27-68-22

Sample ID	Laboratory	Sample type	Sample prep (H_2S)	Total B (mg/L)	Total Li (mg/L)	Total Sr (mg/L)	Total Ca (mg/L)	Total Mg (mg/L)	Total Na (mg/L)	Total K (mg/L)	Total Organic Carbon
P1A 13-27-068-22W5	AGAT	Original	Un-mitigated brine	128.00	65.7	810.00	24,100.00	2,360.00	49,500.00	3,830.00	968.00
P2B 13-27-068-22W5	AGAT	Original	Un-mitigated brine	135.00	70.8	920.00	26,700.00	2,850.00	54,100.00	4,350.00	/
P3C 13-27-068-22W5	AGAT	Original	Un-mitigated brine	148.00	72.4	957.00	27,000.00	2,890.00	57,000.00	4,550.00	/
P4D 13-27-068-22W5	AGAT	Original	Un-mitigated brine	161.00	77.6	1,050.00	28,200.00	3,090.00	62,400.00	4,870.00	317.00
P5E 13-27-068-22W5	AGAT	Original	Un-mitigated brine	154.00	75.8	986.00	27,600.00	3,000.00	59,000.00	4,860.00	/
P6F 13-27-068-22W5	AGAT	Original	Un-mitigated brine	154.00	75.3	999.00	26,800.00	2,930.00	59,900.00	4,780.00	/
			Min	128.00	65.70	810.00	24,100.00	2,360.00	49,500.00	3,830.00	317.00
			Max	161.00	77.60	1,050.00	28,200.00	3,090.00	62,400.00	4,870.00	968.00
			Average	146.67	72.93	953.67	26,733.33	2,853.33	56,983.33	4,540.00	642.50
			Standard deviation	12.64	4.31	82.66	1,408.07	256.18	4,609.30	402.29	460.33
			RSD%	8.6	5.9	8.7	5.3	9.0	8.1	8.9	71.6

C) Well BARRICK STURLKS 10-6-69-21

Sample ID	Laboratory	Sample type	Sample prep (H_2S)	Total B (mg/L)	Total Li (mg/L)	Total Sr (mg/L)	Total Ca (mg/L)	Total Mg (mg/L)	Total Na (mg/L)	Total K (mg/L)	Total Organic Carbon
PB1A 10-06-069-21W5	AGAT	Original	Un-mitigated brine	127.00	69.4	929.00	24,200.00	2,460.00	54,600.00	4,140.00	536.00
PB2B 10-06-069-21W5	AGAT	Original	Un-mitigated brine	132.00	72.3	961.00	25,100.00	2,550.00	56,600.00	4,370.00	/
PB3C 10-06-069-21W5	AGAT	Original	Un-mitigated brine	121.00	65.9	878.00	23,000.00	2,330.00	51,700.00	3,960.00	/
PB4D 10-06-069-21W5	AGAT	Original	Un-mitigated brine	130.00	68.8	940.00	24,600.00	2,420.00	55,300.00	4,140.00	/
PB5E 10-06-069-21W5	AGAT	Original	Un-mitigated brine	131.00	70.3	943.00	24,700.00	2,470.00	55,300.00	4,240.00	/
PB6F 10-06-069-21W5	AGAT	Original	Un-mitigated brine	133.00	72.2	952.00	25,000.00	2,530.00	55,900.00	4,360.00	/
			Min	121.00	65.90	878.00	23,000.00	2,330.00	51,700.00	3,960.00	536.00
			Max	133.00	72.30	961.00	25,100.00	2,550.00	56,600.00	4,370.00	536.00
			Average	129.00	69.82	933.83	24,433.33	2,460.00	54,900.00	4,201.67	536.00
			Standard deviation	4.43	2.39	29.43	771.15	79.50	1,705.29	155.49	/
			RSD%	3.4	3.4	3.2	3.2	3.2	3.1	3.7	/

D) Well CNRL STURLKS 7-25-68-22

Sample ID	Laboratory	Sample type	Sample prep (H_2S)	Total B (mg/L)	Total Li (mg/L)	Total Sr (mg/L)	Total Ca (mg/L)	Total Mg (mg/L)	Total Na (mg/L)	Total K (mg/L)	Total Organic Carbon
PB1A 07-25-068-22W5	AGAT	Original	Un-mitigated brine	119.00	70.9	873.00	23,500.00	2,420.00	53,200.00	4,160.00	212
PB2B 07-25-068-22W5	AGAT	Original	Un-mitigated brine	118.00	71.8	830.00	23,900.00	2,470.00	53,800.00	4,210.00	/
PB3C 07-25-068-22W5	AGAT	Original	Un-mitigated brine	116.00	71.3	822.00	22,100.00	2,450.00	50,600.00	4,180.00	/
PB4D 07-25-068-22W5	AGAT	Original	Un-mitigated brine	111.00	68.8	781.00	22,100.00	2,370.00	49,400.00	4,050.00	/
PB5E 07-25-068-22W5	AGAT	Original	Un-mitigated brine	119.00	70.6	882.00	24,200.00	2,410.00	54,500.00	4,130.00	/
PB6F 07-25-068-22W5	AGAT	Original	Un-mitigated brine	120.00	71.7	877.00	23,900.00	2,440.00	53,800.00	4,190.00	/
			Min	111.00	68.80	781.00	22,100.00	2,370.00	49,400.00	4,050.00	212.00
			Max	120.00	71.80	882.00	24,200.00	2,470.00	54,500.00	4,210.00	212.00
			Average	117.17	70.85	844.17	23,283.33	2,426.67	52,550.00	4,153.33	212.00
			Standard deviation	3.31	1.10	40.06	943.22	35.02	2,053.05	57.50	/
			RSD%	2.8	1.6	4.7	4.1	1.4	3.9	1.4	/

Figure 9.4: Selected geochemical results of LithiumBank's brine assay testing at the Boardwalk Property. Lithium results are highlighted in grey

The quality of the analytical results is assessed using average percent relative standard deviation (% coefficient of variation), or average RSD% as an estimate of precision or reproducibility of the analytical results. The RSD% value is calculated using the formula: RSD% = standard deviation/mean x 100. It is the author's opinion that average RSD% values below 30% are considered to indicate good data quality; between 30 and 50%, moderate quality and over 50%, poor quality.

The RSD% values for brine samples collected from each of the four wells is between 1.6% and 12.3% (Figure 9.3). Brine from wells CNRL STURLKS 13-27-68-22, BARRICK STURLKS 10-6-69-21, and CNRL STURLKS 7-25-68-22, which was analyzed at AGAT Laboratories (only) had low RSD% values of 1.6% to 8.6%. The RSD% of the brine collected and analyzed from well CNRL STURLKS 9-26-68-22 is higher at 12.3% and is directly related to brine being analyzed at both AGAT Laboratories and Bureau Veritas. Regardless, it is concluded that there is very good data quality for LithiumBank's Li-brine analytical results at both independent laboratories.

The historical geochemical composition of Leduc Formation brine, which was sampled within the Sturgeon Lake Oilfield (north and south oilfields) by the Alberta government and companies other than LithiumBank, is 68.0 mg/L Li (n=89 analyses). This historical dataset yields an RSD% of 9.4% and is considered by the QP to have a high-level of analytical precision.

In comparison, the four wells sampled as part of LithiumBank's 2021 brine sampling program yielded average per well values of between 67.7 mg/L Li and 72.9 mg/L Li. The lower value of 67.7 mg/L Li is because brine from well CNRL STURLKS 9-26-68-22 was analyzed at both AGAT and Bureau Veritas. The average lithium value of all 44 brine samples/analyses is 69.9 mg/L Li. In a comparison between the historical and LithiumBank 2021 data, the difference corresponds to a per cent variation of 4.2% between the average historical Leduc brine analytical results and the average lithium value of all 44 brine samples analyzed during LithiumBank's 2021 program.

A histogram of the historical and LithiumBank 2021 lithium analytical results is presented in Figure 9.2. The LithiumBank and historical lithium values correlate well, but generally, the LithiumBank 2021 data do mimic the high end of the historical analytical results.

To conclude, LithiumBank's 2021 assay brine program verified the historical geochemical results, and it is the QP's opinion that the LithiumBank and the historical Li-brine analytical results are reasonable and sufficient for use in mineral resource estimation processes.

In addition, the Leduc Formation brine collected during LithiumBank's 2021 brine sampling program is representative of brine from the Sturgeon Lake Oilfield Leduc Formation reservoir, and therefore, is suitable for mineral processing test work.

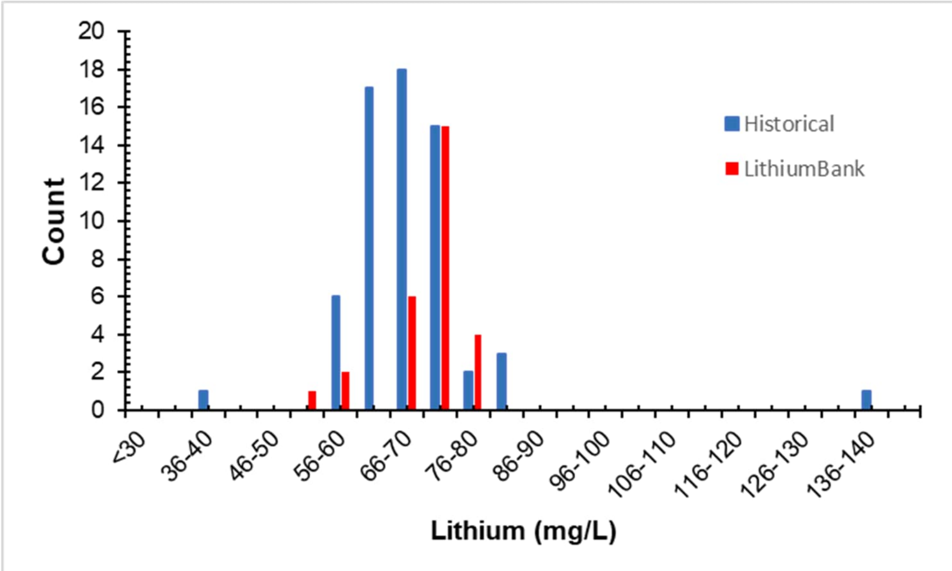


Figure 9.5: Histogram comparing the lithium geochemical results of all historical analyses (n=61) versus the LithiumBank's 2021 analyses (n=28)

9.1.1 LithiumBank's Primary Laboratory Geochemical Summary

LithiumBank's primary laboratory is AGAT Laboratory (see discussion in Section 14.6). A summary of the AGAT-specific routine water geochemical results of Leduc Formation aquifer brine collected during LithiumBank's 2021 brine sampling are presented in Figure 9.3 and Figure 9.4. The table shows a total of 25 original samples were assayed at LithiumBank's primary lab and yield average values of 71.6 mg/L Li, 129.9 mg/L B, 914.8 mg/L Sr, 24,724 mg/L Ca, 2,614 mg/L Mg, 55,332 mg/L Na, and 4,271 mg/L K. The Li-brine values ranged between 65.7 mg/L and 77.6 mg/L Li with an average of 71.6 mg/L Li.

These analytical results were collected and analyzed by LithiumBank at the Company's primary lab using representative Leduc Formation brine from 4 wells located in the Sturgeon Lake South Oilfield. The RSD% of, for example, lithium is 4%, which suggests strong analytical reproducibility.

Hence, and in the QPs opinion, the Li-brine value of 71.6 mg/L Li is representative of the lithium concentration of the Leduc Formation brine underlying the Sturgeon Lake South Oilfield portion of the Sturgeon Lake Reef Complex.

CATIONS

Ion	mg/L	mmol/L	meq/L
Na^+	48000.0	2087.9	2087.9
K^+	5140.0	131.5	131.5
Ca^{2+}	21200.0	529.0	1057.9
Mg^{2+}	2460.0	101.2	202.4
Fe^{2+}	TRACE	TRACE	TRACE
		Total	3479.7

ANIONS

Ion	mg/L	mmol/L	meq/L
Cl^-	125780.0	3547.8	3547.8
HCO_3^-	425.0	7.0	7.0
SO_4^{2-}	237.8	2.5	5.0
CO_3^{2-}	Nil	Nil	Nil
OH^-	Nil	Nil	Nil
		Total	3559.8

0.98
Cation/Anion Ratio

OTHER MEASUREMENTS

203026
TDS (Calculated) mg/L

357.81
H_2S (25°C) mg/L

0.044
Resistivity/OHM·m (25°C)

6.18
Observed pH

1.155
Relative Density (25°C)

19.65
Salinity %

348.33
Total Alkalinity as $CaCO_3$ mg/L

Stiff Diagram (meq/L)

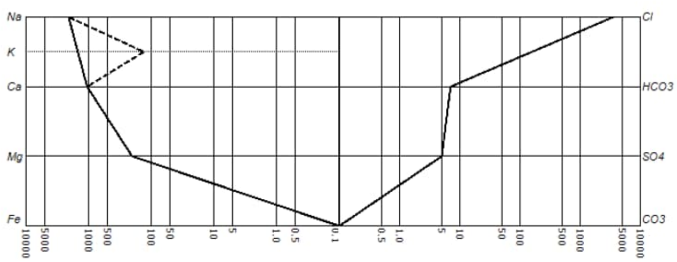


Figure 9.6: Routine water analysis example on Leduc Formation brine from well CNRL SUTRLKS 13-27-068-22

Sample ID	Well ID	Total B (mg/L)	Total Li (mg/L)	Total Sr (mg/L)	Total Ca (mg/L)	Total Mg (mg/L)	Total Na (mg/L)	Total K (mg/L)
RE21-LB-SL-001	CNRL Sturlks 9-26-68-22	129	72.7	927	24,800	2,730	56,500	4,140
RE21-LB-SL-005	CNRL Sturlks 9-26-68-22	126	71.8	939	25,100	2,680	57,200	4,160
RE21-LB-SL-011	CNRL Sturlks 9-26-68-22	126	75.4	963	24,500	2,780	58,500	4,370
RE21-LB-SL-014	CNRL Sturlks 9-26-68-22	130	72.2	905	23,200	2,690	54,300	4,180
RE21-LB-SL-016	CNRL Sturlks 9-26-68-22	128	73.4	941	25,300	2,710	57,700	4,280
RE21-LB-SL-020	CNRL Sturlks 9-26-68-22	121	68.8	851	23,200	2,560	53,400	3,960
RE21-LB-SL-026	CNRL Sturlks 9-26-68-22	131	74.8	954	25,300	2,760	59,100	4,320
P1A 13-27-068-22W5	CNRL Sturlks 13-27-68-22	128	65.7	810	24,100	2,360	49,500	3,830
P2B 13-27-068-22W5	CNRL Sturlks 13-27-68-22	135	70.8	920	26,700	2,850	54,100	4,350
P3C 13-27-068-22W5	CNRL Sturlks 13-27-68-22	148	72.4	957	27,000	2,890	57,000	4,550
P4D 13-27-068-22W5	CNRL Sturlks 13-27-68-22	161	77.6	1,050	28,200	3,090	62,400	4,870
P5E 13-27-068-22W5	CNRL Sturlks 13-27-68-22	154	75.8	986	27,600	3,000	59,000	4,860
P6F 13-27-068-22W5	CNRL Sturlks 13-27-68-22	154	75.3	999	26,800	2,930	59,900	4,780
PB1A 10-06-069-21W5	Barrick Sturlks 10-6-69-21	127	69.4	929	24,200	2,460	54,600	4,140
PB2B 10-06-069-21W5	Barrick Sturlks 10-6-69-21	132	72.3	961	25,100	2,550	56,600	4,370
PB3C 10-06-069-21W5	Barrick Sturlks 10-6-69-21	121	65.9	878	23,000	2,330	51,700	3,960
PB4D 10-06-069-21W5	Barrick Sturlks 10-6-69-21	130	68.8	940	24,600	2,420	55,300	4,140
PB5E 10-06-069-21W5	Barrick Sturlks 10-6-69-21	131	70.3	943	24,700	2,470	55,300	4,240
PB6F 10-06-069-21W5	Barrick Sturlks 10-6-69-21	133	72.2	952	25,000	2,530	55,900	4,360
PB1A 07-25-068-22W5	CNRL Sturlks 7-25-68-22	119	70.9	873	23,500	2,420	53,200	4,160
PB2B 07-25-068-22W5	CNRL Sturlks 7-25-68-22	118	71.8	830	23,900	2,470	53,800	4,210
PB3C 07-25-068-22W5	CNRL Sturlks 7-25-68-22	116	71.3	822	22,100	2,450	50,600	4,180
PB4D 07-25-068-22W5	CNRL Sturlks 7-25-68-22	111	68.8	781	22,100	2,370	49,400	4,050
PB5E 07-25-068-22W5	CNRL Sturlks 7-25-68-22	119	70.6	882	24,200	2,410	54,500	4,130
PB6F 07-25-068-22W5	CNRL Sturlks 7-25-68-22	120	71.7	877	23,900	2,440	53,800	4,190
	Count	25	25	25	25	25	25	25
	Min	**111**	**65.70**	**781**	**22,100**	**2,330**	**49,400**	**3,830**
	Max	**161**	**77.60**	**1,050**	**28,200**	**3,090**	**62,400**	**4,870**
	Average	**129.9**	**71.6**	**914.8**	**24,724.0**	**2,614.0**	**55,332.0**	**4,271.2**
	Standard deviation	**12.5**	**2.9**	**63.6**	**1,581.5**	**218.6**	**3,196.7**	**261.4**
	RSD%	**9.6**	**4.0**	**7.0**	**6.4**	**8.4**	**5.8**	**6.1**

Figure 9.7: Analytical summary of selected elemental results from LithiumBank's primary laboratory (AGAT Laboratories)

9.1.2 Other Leduc Formation Brine Measurements

In addition to trace element geochemistry by ICP analytical work, LithiumBank also conducted routine water analysis and Total Organic Carbon (TOC) analysis. This analytical work was completed in advance of mineral processing test work.

An example of a routine water analysis, including cation, anion, and other measurements and the logarithmic pattern of dissolved ions (meq/L), of Leduc Formation brine from well CNRL

SUTRLKS 13-27-068-22 is presented in Figure 9.3. The analytical results show a brine salinity of 19.7%, relative density of 1.155 g/cm^3, observed pH of 6.18, total alkalinity as CaCO3 of 348.3 mg/L, and calculated total dissolved solids content of 203,026 mg/L TDS. The analytical charge imbalance is 0.98%.

A total of 7 TOC measurements were completed including at least one analysis on the Leduc Formation brine per each of the 4 wells tested. The TOC is an indirect measure, of carbon, as organic molecules present in waters. The analytical results of the TOC measurements are presented in Table 9.5.

The Leduc Formation brine samples have a wide variation in TOC content, between 157 mg/L and 968 mg/L TOC. The TOC was highest in un-mitigated brine from wells CNRL STURLKS 13-27-68-22 and BARRICK STURLKS 10-6-69-21 (317, 536, and 968 mg/L TOC) and lowest in the mitigated brine from well CNRL STURLKS 9-26-68-22 (157 and 166 mg/L). The latter suggests it is possible that the AMGAS mitigation process may reduce the TOC content of the Leduc Formation brine, but further work is required to prove or dismiss this assumption.

Higher lithium values generally correspond with lower TOC (Table 9.4), but additional data, and or a wider range of values, is required to validate this observation.

LithiumBank Sub-Property	UWI	Well name	Sample prep (H_2S)	Total Organic Carbon (mg/L)	Li (mg/L)
Sturgeon Lake	100/09-26-068-22W5/00	CNRL STURLKS 9-26-68-22	Un-mitigated brine	279.0	72.7
Sturgeon Lake	100/09-26-068-22W5/00	CNRL STURLKS 9-26-68-22	Mitigated at AmGas	166.0	71.8
Sturgeon Lake	100/09-26-068-22W5/00	CNRL STURLKS 9-26-68-22	Mitigated at AmGas	157.0	74.8
Sturgeon Lake	100/13-27-068-22W5/00	CNRL STURLKS 13-27-68-22	Un-mitigated brine	968.0	65.7
Sturgeon Lake	100/13-27-068-22W5/00	CNRL STURLKS 13-27-68-22	Un-mitigated brine	317.0	77.6
Sturgeon Lake	100/10-06-069-21W5/00	BARRICK STURLKS 10-6-69-21	Un-mitigated brine	536.0	69.4
Sturgeon Lake	100/07-25-068-22W5/00	CNRL STURLKS 7-25-68-22	Un-mitigated brine	212.0	70.9

Figure 9.8: Summary of Total Organic Carbon analyses conducted by LithiumBank

9.2 LithiumBank 2021 Bulk Brine Mineral Processing Sample Collection

Approximately 20 m^3 of Leduc Formation aquifer brine was stored within a holding vessel at each of the four wells (80 m^3 of brine total). The brine from the holding tank was transferred to a tanker truck for transport from the well site to Amgas' facility for mitigation of the H_2S and storage of the sweetened water product prior to mineral processing test work. The sweetened bulk brine was stored in separate allotments at Amgas' secure holding yard.

The brine samples were sent to independent laboratories for mineral processing test work, the results of the work, which was completed in 2022, are discussed in Section 13.

9.3 LithiumBank 2021 Existing Seismic Survey Interpretation

During 2021, LithiumBank acquired a series of existing 2-D seismic line profiles and data that encompasses their Boardwalk Property. The seismic data was purchased from Pulse Seismic Inc., a Calgary, AB public company that specializes in the acquisition, inventorying, licensing, and sale of existing 2-D and 3-D seismic data to the western Canadian energy sector.

The seismic information included a total of seven, 2-D seismic lines totaling 67 line-kilometres. The original seismic surveys were conducted between 1982 and 1990. The seismic data was supplied as: migrated stack sections as segy files downloaded to Seisware Project along with DVD containing basic, field and stack data. Four of the seven seismic lines are orientated in a northeast direction with the remaining three seismic lines orientated east-west. The lines capture the eastern edge of the Leduc fringing reef, the internal structure of the reef buildup, and the western edge of the reef formation in the south Sturgeon Lake Oilfield.

The seismic lines cover portions of Alberta Township land surveying system Township 68, 69 and 70, and Range 22 and 23 West of the 5th Meridian. This area effectively covers the region of the South Sturgeon Lake Oilfield and the southern portion of LithiumBank's Property (see Figure 9.1).

LithiumBank commissioned Diane Shao, a consulting Senior Geologist/Geophysicist in Calgary, AB, to re-interpret the existing 2-D seismic data. The main objectives of the reinterpretation were to help characterize and identify 1) fault and shear zones, 2) reservoir quality, and 3) better define the Leduc Formation reef in the western part of the Property where there is little to no well control. The reinterpretation was performed using the seismic data in the format in which it was acquired, and by utilizing stratigraphic top picks as provided in GeoSCOUT, a popular petroleum industry data and software program from geoLogic Systems of Calgary, AB.

As per the acquisition agreement between LithiumBank and Pulse Seismic Inc., the seismic line profiles are proprietary. A non-spatially orientated example of a seismic section is presented in Figure 9.9 and shows the relationship between proposed basement fault zones and the Sturgeon Lake Reef Complex carbonate buildups.

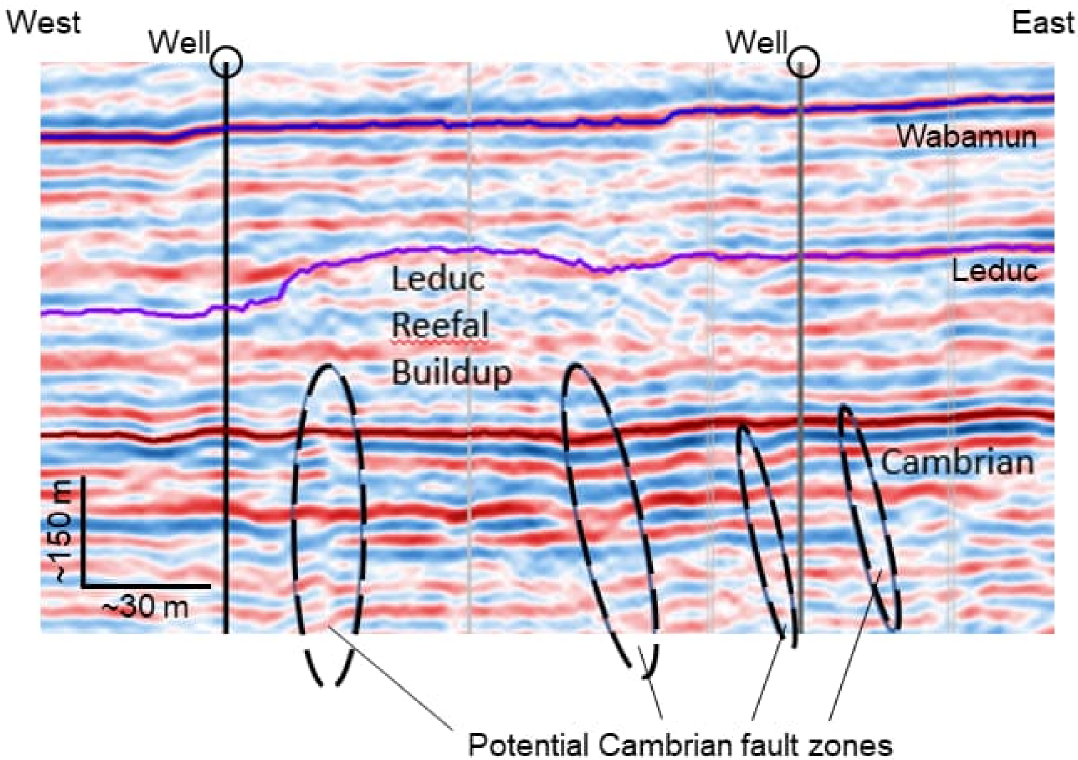


Figure 9.9: Two-dimensional seismic image of the Leduc Formation interior-back reef in the Boardwalk Property. The Leduc reef obtains thicknesses of approximately 160 m in reefal buildup in this example

Generalized comments of the seismic reinterpretation in conjunction with LithiumBank's objective are presented as follows.

- Numerous fault zones occur within Cambrian strata underlying the Leduc Formation reef.
- The reflective nature of the Leduc reef made it difficult to interpret the propagating extension of these fault zones from the Cambrian upward into the Leduc Formation reef; it is hypothesized that some, if not all, of the faults would propagate into the lower portion, or through much of the reefal units.
- It was difficult to interpret and comment on quality of the reservoir because porous limestone unit will look like a tight dolomite unit in the 2-D seismic line profiles.
- Reservoir thickness of the main Leduc reef trend was easily interpreted on the seven 2-D lines. On the eastern side of the main reef trend, the Leduc Formation isopach is around 250 m thick, while on the western side of the main reef trend, it thickens to approximately 330 m.
- With respect to the Leduc Formation thickness in the western part of the Property, a couple of 2-D lines displayed the potential that the reef extends westward for

approximately 1.5 km from in comparison to publicly available reef edge estimations (e.g., Switzer et al., 1994). It is possible that acquisition of additional 3-D seismic data could provide a more accurate assessment of the western edge of the Leduc Formation in this area.

To conclude, LithiumBank's 2021 acquisition and reinterpretation of existing seismic data in the south Boardwalk Property has enabled the Company to have a better understanding of the dimensions of the Sturgeon Lake Reef Complex. The seismic information advanced the Company's understanding of the underlying structural geology that may be responsible for the location and development of the reefs and could potentially act as sources of fluid flow of hot geothermal fluids that may be enriched in lithium from the crystalline basement and/or clastic units overlying the basement (i.e., the Granite Wash).

9.4 Hydrogeological Characterization Study

LithiumBank commissioned Hydrogeological Consultants Ltd. (HCL) in Edmonton, AB to conduct a hydrogeological assessment of the Leduc Formation aquifer within the Sturgeon Lake Reef Complex underlying the Boardwalk Property.

The hydrogeological assessment of the Sturgeon Lake Reef Complex was investigated using a variety of public and proprietary sources. Based on analysis of effective porosity from 99 separate core plug measurements and total porosity derived from geophysical logs, the representative average effective porosity of the Leduc Formation underlying the Boardwalk Property is 5.3%.

Based on 2008-2011 production data (n=46 wells), the average modal abundance of brine in the Leduc formation pore space is 98%. Based on drill stem tests, a permeability of 19 mD is considered most representative of the Leduc Formation. The best estimate from the existing data of calculated transmissivity is 7.4 m^2/day with a storativity of 8.0×10^{-4}.

Details of the hydrogeological study are presented in Section 14.3.

10. Drilling

LithiumBank has not drilled any wells and is reliant on current Petro-operators and infrastructure associated with their Petro-operations and petroleum production to access deep Leduc Formation aquifer brine within the Sturgeon Lake Oilfield and Property.

The well status of the Sturgeon Lake Oilfield is currently in a suspended state. During 2021, however, LithiumBank formed a brine access agreement with CNRL to reopen 4 wells to acquire Leduc Formation brine for assay testing and mineral processing test work. Once LithiumBank collected the brine samples, the wells were then returned to their suspended state by the Petro-operator.

In addition to the brine samples collected at the four re-opened wells, LithiumBank is also reliant on historical brine assays to form the assay file utilized in the resource estimation. This includes brine sampling programs completed by Lithium Exploration Group Inc. in 2011 and MGX Minerals Inc. in 2016.

Accordingly, this drilling section provides summary descriptions and brine analytical results of wells associated with:

- The historical Lithium Exploration Group Inc. 2011 sampling program presented in Section 10.1.
- The historical MGX Minerals Inc. 2016 sampling program presented in Section 10.2.
- LithiumBank's 2021 sample program presented in Section 10.3.

10.1 Lithium Exploration Group Inc.'s 2011 Brine Sampling Program and Analytical Results

In 2011, Maxxam Environmental collected routine brine samples on behalf of Lithium Exploration Group Inc. The wells sampled were all within the boundaries of the current LithiumBank Boardwalk Property (see Figure 6.1).

A total of 62 samples were collected from 60 separate wells within the Valleyview Property. Of the 62 samples, 47 were collected from the Leduc Formation aquifer. Other samples included formation waters from: Mississippian (1 sample from Banff), Triassic (11 samples from Montney, Spray River and undefined), Jurassic (1 sample from Nordegg) and Cretaceous (2 samples from Wapiabi, Gething) samples.

A summary of the selected geochemical elements is presented in Figure 10.3 with a histogram of lithium results in Figure 10.1.

Figure 10.1 shows that Li is the most significant element of economic interest in the brine samples, although K, B, Br, Mg, Ca, and Na provide potential co-products pending extractability processes.

The bimodal lithium variation in Figure 10.1 is directly related to chemical dissimilarities between the Leduc aquifer brine (>60 mg/L Li) versus those from the Mississippian to Cretaceous sampled formation waters (<40 mg/L Li). The histogram also illustrates the well-constrained, single population for the Leduc Formation Li-brine (n=47 analyses) with a mean lithium value of 67.5 mg/L Li.

Well identifier	Group/Formation	Lithium (Li) (mg/L)	Potassium (K) (mg/L)	Boron (B) (mg/L)	Bromine (Br) (mg/L)	Calcium (Ca) (mg/L)	Magnesium (Mg) (mg/L)	Sodium (Na) (mg/L)
01-01-069-22-W5M	Devonian - Leduc	71.8	5200	130	380	26300	3640	70900
01-06-069-21-W5M	Devonian - Leduc	65.5	4280	109	390	23400	2390	59800
01-08-069-21-W5M	Triassic - Montney	25.4	1310	20.8	190	2690	628	52000
01-31-068-21-W5M	Devonian - Leduc	64.6	4420	109	400	24100	2530	65200
02-02-069-22-W5M	Devonian - Leduc	69.6	4500	114	380	23400	2740	64400
02-12-069-22-W5M	Devonian - Leduc	66.2	4250	114	410	22500	2510	62700
02-20-069-22-W5M	Devonian - Leduc	59.3	4130	92.4	330	19800	2300	52200
03-12-069-22-W5M	Devonian - Leduc	76.9	5620	137	390	27600	3860	69500
03-25-068-22-W5M	Cretaceous - Gething	21.8	1320	13.1	170	2950	763	62500
04-03-069-22-W5M	Devonian - Leduc	65.6	4270	105	390	22700	2540	61300
04-12-069-22-W5M	Devonian - Leduc	64.8	4360	109	400	22800	2490	60300
05-05-069-21-W5M	Devonian - Leduc	70.2	5090	134	390	26900	3560	69000
05-05-072-23-W5M	Devonian - Leduc	57.3	4150	94.5	360	22100	2400	56100
05-09-069-21-W5M	Devonian - Leduc	73.2	5060	137	390	27800	3780	67800
05-10-069-21-W5M	Devonian - Leduc	74.4	4370	122	350	22000	2900	57200
05-12-069-22-W5M	Devonian - Leduc	68.3	4460	115	390	22500	2670	60900
05-19-068-21-W5M	Triassic - Montney	22.3	1360	12.9	170	3040	768	63800
05-32-071-23-W5M	Devonian - Leduc	74	5280	122	430	26900	3460	70500
06-05-069-21-W5M	Devonian - Leduc	66.2	4460	103	390	20100	2910	61100
06-06-069-21-W5M	Devonian - Leduc	65.2	4370	112	370	22500	2530	61100
06-08-069-21-W5M	Triassic - undefined	27	1480	24	180	3150	803	66400
06-11-069-22-W5M	Devonian - Leduc	66.9	3950	116	360	23400	2720	61600
06-36-068-22-W5M	Devonian - Leduc	59.9	4220	99.4	350	21300	2380	57600
07-06-069-21-W5M	Devonian - Leduc	65.7	4440	111	440	23000	2530	61000
07-11-069-22-W5M	Devonian - Leduc	64.2	4320	108	370	22500	2490	59500
07-12-069-22-W5M	Triassic - Montney	22	1180	36.3	170	2320	560	50500
07-19-069-22-W5M	Devonian - Leduc	71.4	4780	113	390	23700	2840	60200
07-21-071-23-W5M	Devonian - Leduc	55.4	3980	97	400	21700	2430	52700
07-26-069-23-W5M	Devonian - Leduc	72.7	5390	122	420	23900	3510	65100
08-09-069-21-W5M	Devonian - Leduc	70.5	4290	115	380	23800	2580	58400
08-11-069-22-W5M	Devonian - Leduc	65.6	4330	111	410	22600	2560	60000
08-34-068-22-W5M	Devonian - Leduc	62.5	4200	102	370	21700	2490	59300
09-01-069-22-W5M	Devonian - Leduc	64.8	4200	104	460	23000	2380	59200
10-01-069-22-W5M	Devonian - Leduc	65.8	4420	113	470	22800	2550	61700
10-05-069-21-W5M	Devonian - Leduc	83.7	6470	136	390	28100	4630	67900
10-06-069-21-W5M	Devonian - Leduc	74.3	4920	124	450	21500	2830	58800
10-06-069-21-W5M	Triassic - undefined	24.7	1250	17.9	180	2870	606	55200
10-11-069-22-W5M	Devonian - Leduc	65.7	4260	111	380	22000	2580	60100
10-11-069-22-W5M	Triassic - Montney	26.3	1460	20.8	180	3100	845	61500
11-04-069-21-W5M	Triassic - Montney	26.1	1370	20.4	210	2770	636	53500
11-05-069-21-W5M	Mississipian - Banff	17	954	18.2	140	1790	526	42500
11-06-069-21-W5M	Devonian - Leduc	70.9	5170	127	390	26200	3380	67700
11-06-072-23-W5M	Devonian - Leduc	71.8	5210	120	410	26100	3410	66000
11-07-069-21-W5M	Triassic - Montney	25.4	1250	20.9	210	2810	614	53300
11-11-069-22-W5M	Devonian - Leduc	68.7	5050	126	380	25800	3540	65300
11-12-069-22-W5M	Jurassic - Nordegg	24	1250	19.7	200	2700	631	54500
11-16-071-23-W5M	Devonian - Leduc	73.8	5270	125	430	26100	3520	66200
11-36-068-22-W5M	Devonian - Leduc	72.5	5220	130	380	26200	3740	71400

Figure 10.1: Summary of selected elements from Lithium Exploration Group Inc.'s 2011 Sturgeon Lake Oilfield brine geochemical sampling program

Well identifier	Group/Formation	Lithium (Li) (mg/L)	Potassium (K) (mg/L)	Boron (B) (mg/L)	Bromine (Br) (mg/L)	Calcium (Ca) (mg/L)	Magnesium (Mg) (mg/L)	Sodium (Na) (mg/L)
12-05-069-21-W5M	Devonian - Leduc	67.4	4460	110	370	21600	2600	63100
12-19-069-22-W5M	Devonian - Leduc	58.1	4370	96.6	400	21700	2570	57600
13-05-069-21-W5M	Triassic - Spray River	29.1	1560	29.6	220	5370	805	54700
13-06-069-21-W5M	Triassic - Montney	25.7	1410	20.5	180	3050	810	62300
13-27-068-22-W5M	Devonian - Leduc	61.1	4440	101	360	22200	2560	60000
13-31-068-21-W5M	Devonian - Leduc	71.5	5250	128	380	26100	3600	69500
14-32-071-23-W5M	Devonian - Leduc	59.6	4310	100	390	23000	2530	58600
14-34-068-22-W5M	Devonian - Leduc	65.2	4390	103	370	22500	2620	62400
15-05-069-21-W5M	Triassic - Montney	17.1	876	18.5	190	1680	414	37200
15-31-068-21-W5M	Devonian - Leduc	66.5	4570	111	400	23400	2550	63800
16-10-069-22-W5M	Devonian - Leduc	66.9	4600	108	350	21000	2560	57500
16-17-069-22-W5M	Cretaceous - Wapiabi	41.3	3230	68	350	14000	1660	39600
16-29-071-23-W5M	Devonian - Leduc	70.5	4970	123	500	26300	3300	65700
16-31-068-21-W5M	Devonian - Leduc	65.7	4420	108	440	22400	2520	64200

Figure 10.2: Summary of selected elements from Lithium Exploration Group Inc.'s 2011 Sturgeon Lake Oilfield brine geochemical sampling program, continued

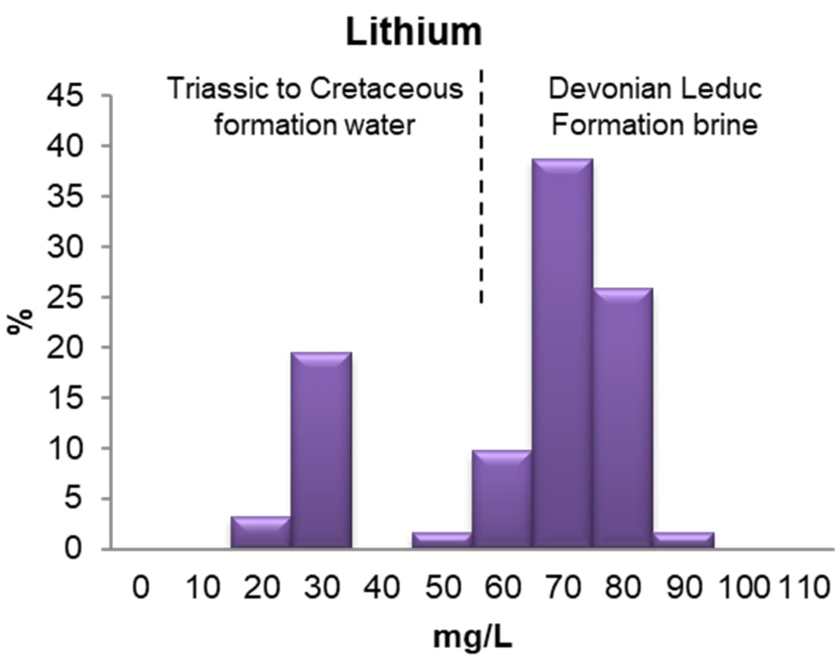


Figure 10.3: Histogram of lithium geochemical results from Lithium Exploration Group Inc.'s 2011 Sturgeon Lake Oilfield brine geochemical sampling program

10.2 MGX Minerals Inc. 2016 Brine Sampling Program and Analytical Results

In 2016, a Li-brine assay sampling program was conducted by APEX on behalf of MGX from individual wells producing from the Leduc Formation, and at the Sturgeon Lake Gas Plant, which collects the pumped product from all wellheads in the Sturgeon Lake Oilfield. The wells sampled were all within the boundaries of the current LithiumBank Boardwalk Property (see Figure 6.1).

A total of 13 samples were collected including: seven samples of individual wells (three wells from the Sturgeon Lake South Oilfield; three wells from the Sturgeon Lake North Oilfield; and an assay sample from the main water dispersal line at the Sturgeon Lake South Gas Plant); five duplicate samples to test analytical precision (two from individual wells and three at the Sturgeon Lake Gas Plant; and one control sample (non-Li-bearing water to test laboratory protocol).

The well sample locations and descriptions are presented in Figure 10.1. A description of the individual brine samples is presented in Figure 10.3. A summary of the selected analytical results including duplicate samples and control blank samples is presented in Figure 10.4. Apart from sample RE16-MGX-SL004 (well 00/05-15-069-22W5), the brine assay results show a homogeneous concentration of lithium. The average lithium value for the 2016 brine samples is 59.3 mg/L for all samples, and 61.5 mg/L when sample RE16-MGX-SL004 is omitted. The QP suggests omitting the results of brine from sample RE16-MGX-SL004 because the well is adjacent to a competitor's 'Class 1 Disposal Well'. Hence the sample could include some amount of contamination within the aquifer from Class 1 miscellaneous hazardous and chemical waste.

The analytical results for other elements of interest, including bromide, potassium, and boron, are also presented in Figure 10.4. The average value for all samples including RE16-GX-SL004 is 351.7 mg/L Br, 4387.5 mg/L K and 106.1 mg/L B, while the average values all samples excluding RE16-MGX-SL004 are 361.8 mg/L Br, 4529.1 mg/L K and 109.6 mg/L B.

Samples taken from the Sturgeon Lake Gas Plant are highlighted in blue in Figure 10.4 and have similar lithium values compared to those for the individual wells. The average lithium value for samples of individual wells is 58.7 mg/L while the average Li value for the samples taken at the Sturgeon Lake Gas Plant is 60.5 mg/L with an RSD% of 0.44% (note: the RSD% is a measure of the precision and reproducibility of the analytical results, values of <10% are considered to show good precision and reproducibility; 0.44% is excellent precision and reproducibility).

The similarity in the lithium content of the brine in the individual wells and those at the Sturgeon Lake Gas Plant is an important observation because the Sturgeon Lake Gas Plant collects Leduc Formation brine from throughout the Property, and therefore, represents the main brine collection site on the southern portion of the Boardwalk Property. I.e., If the Li-brine opportunity ever reaches an economic feasibility stage, the Sturgeon Lake Gas Plant would represent a logical pilot testing plant site.

Sample ID	UWI	Operator name	Well name	Sample date	Sample type (original, duplicate, blank)	Latitude	Longitude	Field name	Pool name	Geological formation	Well total depth (m)
					Sample location						
RE16-MGX-SL001	00/08-34-068-22W5	CNRL	BARRICK STURLKS 8-34	14-Dec-16	Original	54.921345	-117.265048	Sturgeon Lake South	D-3	Leduc	3,287.0
RE16-MGX-SL002	02-02-069-22W5	CNRL	STURGEON 2-2-69-22W5	14-Dec-16	Original	54.938707	-117.239285	Sturgeon Lake Gas Plant	/	/	/
RE16-MGX-SL003	02-02-069-22W5	CNRL	STURGEON 2-2-69-22W5	14-Dec-16	Dup1	54.938707	-117.239285	Sturgeon Lake Gas Plant	/	/	/
RE16-MGX-SL004	00/05-15-069-22W5	CNRL	BARRICK STURLKS 5-15	14-Dec-16	Original	54.972373	-117.277528	Sturgeon Lake South	D-3	Leduc	2,607.9
RE16-MGX-SL005	02/07-19-069-22W5	CNRL	CNRL STURLKS 7-19-69-	14-Dec-16	Original	54.986771	-117.341293	Sturgeon Lake South	D-3	Leduc	2,646.9
RE16-MGX-SL006	02/07-19-069-22W5	CNRL	CNRL STURLKS 7-19-69-	14-Dec-16	Duplicate	54.986771	-117.341293	Sturgeon Lake South	D-3	Leduc	2,646.9
RE16-MGX-SL007	Control Blank	/	/	/	/	/	/	/	/	/	/
RE16-MGX-SL008	02-02-069-22W5	CNRL	STURGEON 2-2-69-22W5	14-Dec-16	Dup2	54.938707	-117.239285	Sturgeon Lake Gas Plant	/	/	/
RE16-MGX-SL009	02/16-29-071-23W5	CNRL	BARRICK 102 STURLK 1	14-Dec-16	Original	55.183647	-117.498285	Sturgeon Lake North	D-3	Leduc	3,141.2
RE16-MGX-SL010	02/16-29-071-23W5	CNRL	BARRICK 102 STURLK 1	14-Dec-16	Duplicate	55.183647	-117.498285	Sturgeon Lake North	D-3	Leduc	3,141.2
RE16-MGX-SL011	02/08-06-072-23W5	CNRL	CNRL STURLK 10-6-72-2	14-Dec-16	Original	55.207599	-117.521873	Sturgeon Lake North	D-3	Leduc	2,820.0
RE16-MGX-SL012	02/06-21-071-23W5	CNRL	BARRICK 102 STURLK 6-	14-Dec-16	Original	55.163748	-117.477702	Sturgeon Lake North	D-3	Leduc	2,688.5
RE16-MGX-SL013	02-02-069-22W5	CNRL	STURGEON 2-2-69-22W5	14-Dec-16	Dup3	54.938707	-117.239285	Sturgeon Lake Gas Plant	/	/	/

Figure 10.4: MGX Minerals Inc. well sample locations and descriptions

Sample ID	UWI	Sample point	Purging method	Sample vessel	Fluid type (water, emulsion, etc)	Water colour (pre-separation)	Water colour (post separation)	Sediment present (modal abundance %)	Oil present (modal abundance %)	Sample treatment (by sampler)	Temperature (°C)	Comments
RE16-MGX-SL001	00/08-34-068-22W5	Test separator	One litre in a waste can	Plastic jug	Water	Milky clear	Clear	0	<1	None	n/a	
RE16-MGX-SL002	02-02-069-22W5	Disposal line	Not required	Plastic jug	Water	Clear	Clear	0	0	None	~60	Main diposal line sample nipple at Gas plant
RE16-MGX-SL003	02-02-069-22W5	Disposal line	Not required	Plastic jug	Water	Clear	Clear	0	0	None	~60	Main diposal line sample nipple at Gas plant
RE16-MGX-SL004	00/05-15-069-22W5	Test separator	One litre in a waste can	Plastic jug	Water	Clear	Clear	0	<1	None	n/a	Note: right beside a Class A disposal well (contamination a sure factor)
RE16-MGX-SL005	02/07-19-069-22W5	Test separator	One litre in a waste can	Plastic jug	Water	Clear	Clear	0	<1	None	n/a	
RE16-MGX-SL006	02/07-19-069-22W5	Test separator	One litre in a waste can	Plastic jug	Water	Clear	Clear	0	<1	None	n/a	
RE16-MGX-SL007	Control Blank	/	/	/	/	/	/	/	/	/	/	/
RE16-MGX-SL008	02-02-069-22W5	Disposal line	Not required	Plastic jug	Water	Clear	Clear	0	0	None	~60	Main diposal line sample nipple at Gas plant
RE16-MGX-SL009	02/16-29-071-23W5	Test separator	One litre in a waste can	Plastic jug	Water	Milky clear	Clear	0	<1	None	n/a	North field has slightly more oil in samples
RE16-MGX-SL010	02/16-29-071-23W5	Test separator	One litre in a waste can	Plastic jug	Water	Milky clear	Clear	0	<1	None	n/a	
RE16-MGX-SL011	02/08-06-072-23W5	Test separator	One litre in a waste can	Plastic jug	Water	Clear - slight oil	Clear	0	1-3	None	n/a	
RE16-MGX-SL012	02/06-21-071-23W5	Test separator	One litre in a waste can	Plastic jug	Water	Clear - slight oil	Clear	0	1-3	None	n/a	
RE16-MGX-SL013	02-02-069-22W5	Disposal line	Not required	Plastic jug	Water	Clear	Clear	0	0	None	~60	Main diposal line sample nipple at Gas plant

Figure 10.5: MGX Minerals Inc. individual brine sample descriptions

Sample ID	UWI	Sample type	Lithium (mg/L)	Bromide (mg/L)	Potassium (mg/L)	Boron (mg/L)
RE16-MGX-SL001	00/08-34-068-22W5	Original	60.7	330.0	4,230.0	106.0
RE16-MGX-SL002	02-02-069-22W5	Original	60.3	400.0	4,330.0	109.0
RE16-MGX-SL003	02-02-069-22W5	Dup1	60.2	380.0	4,330.0	110.0
RE16-MGX-SL004	00/05-15-069-22W5	Original	35.6	240.0	2,830.0	67.0
RE16-MGX-SL005	02/07-19-069-22W5	Original	64.3	400.0	4,670.0	113.0
RE16-MGX-SL006	02/07-19-069-22W5	Duplicate	64.7	390.0	4,690.0	113.0
RE16-MGX-SL007	Control Blank	Control blank	0.0	0.0	1.1	0.0
RE16-MGX-SL008	02-02-069-22W5	Dup2	60.5	280.0	4,350.0	110.0
RE16-MGX-SL009	02/16-29-071-23W5	Original	60.5	380.0	4,600.0	109.0
RE16-MGX-SL010	02/16-29-071-23W5	Duplicate	60.9	350.0	4,640.0	109.0
RE16-MGX-SL011	02/08-06-072-23W5	Original	61.9	370.0	4,730.0	108.0
RE16-MGX-SL012	02/06-21-071-23W5	Original	61.2	310.0	4,620.0	109.0
RE16-MGX-SL013	02-02-069-22W5	Dup3	60.8	390.0	4,630.0	110.0
		Min	**35.6**	**240.0**	**2,830.0**	**67.0**
		Max	**64.7**	**400.0**	**4,730.0**	**113.0**
		Avg	**59.3**	**351.7**	**4,387.5**	**106.1**
		Avg (without well 05-15)	**61.5**	**361.8**	**4,529.1**	**109.6**
		Sturgeon Lake South Facility brine average	60.5	362.5	4410.0	109.8
		Sturgeon Lake South Facility brine RSD%	0.44	15.34	3.33	0.46
		SRC analytical results (2017)	71	334	4212	/

Figure 10.6: Summary of selected MGX Minerals Inc. analytical results including duplicate samples and control blank samples. Brine samples from the Sturgeon Lake South Gas Plant are highlighted in blue

10.3 Description of Wells Associated with LithiumBank's 2021 Brine Sampling Program

A summary of the four wells that were re-entered while under suspended well status to collect brine on behalf of LithiumBank is included in Figure 9.1 and Figure 9.2. The wells are currently owned and maintained by the Petro-company. The four wells were accessed exclusively for LithiumBank's 2021 exploration program, and in accordance with NI 43-101, a brief description of the wells is provided in the text that follows. The wells include: CNRL STURLKS 9-26-68-22, CNRL STURLKS 13-27-68-22, CNRL STURLKS 7-25-68-22, and BARRICK STURLKS 10-6-69-21. The well information was accessed through a third-party software program, AbaData (v. 2.0).

Wells CNRL STURLKS 9-26-68-22, CNRL STURLKS 13-27-68-22, and CNRL STURLKS 7-25-68-22 were originally spudded between 1955 and 1956. Well BARRICK STURLKS 10-6-69-21 was drilled in 2005. All the wells were drilled with the intent to produce petroleum products.

With respect to the well status history of the four oil and gas wells:

- CNRL STURLKS 9-26-68-22 was drilled and utilized by oil and gas companies as a water disposal well.
- CNRL STURLKS 13-27-68-22 was drilled and utilized by oil and gas companies as a crude oil well.
- BARRICK STURLKS 10-6-69-21 was drilled and utilized by oil and gas companies as a crude oil well.
- CNRL STURLKS 7-25-68-22 was drilled and utilized by oil and gas companies as a crude oil well until 1977 when the well was converted to a water disposal well.

The original oil and gas well drill companies and drill logistics were not researched. The surface and production casings of the four wells are 244.5 mm to 273.0 mm and 139.7 mm to 177.8 mm, respectively. All four wells were drilled vertically with an azimuth and dip of 0° and -90°, respectively. AbaData reports show none of the wells involved direction drilling. The surface and downhole coordinates are identical for each of the respective wells as provided within AbaData (Figure 9.1).

The target Leduc Formation reservoir was interested in the four wells at depths of between -2,561.8 m to -2,609.1 m below the earth's surface. The maximum total depth of the four wells is -2,706.0 m below surface. It is noted by the authors that the wells must have deviated to depths of >2,500 m but the absolute sample length and the true thickness of the mineralization is not important in this type of confined aquifer Li-brine deposit type. This is because the target unit is defined as a large porous reservoir within the Sturgeon Lake Reef Complex with Li-brine mineralization defined as a fluid.

Hence, once the well bore taps into the porous reservoir, the fluids within the reservoir can be extracted through to depletion. In fact, production graphs of the Sturgeon Lake Oilfield wells show that the oil to water ratio has transitioned over decades of petroleum production to the point where the wells now produce low volumes of oil with increasingly higher volumes of brine. Presently, the amount of brine in the Leduc Formation pore space at the Boardwalk Property is approximately 98% (see Section 14.3.7), which relates to the Sturgeon Lake Oilfield being classified as a mature Devonian petroleum reservoir.

The geochemical results of Leduc Formation brine collected from the four oil and gas wells, and analyzed, by LithiumBank is described in Section 9.1 and summarized in Figure 9.4. The historical geochemical data from the Leduc Formation within the Boardwalk Property is described in Sections 6.2 and 6.3. Collectively, the analytical results demonstrate the lithium content of the Leduc Formation brine within the Sturgeon Lake Reef Complex, regardless of spatial location or depth within the Sturgeon Lake Oilfield, is uniformly homogeneous (55-89 mg/L Li; average of 68.8 mg/L Li; n=89 analyses with an RSD% of 9.1%).

11. Sample Preparation, Analyses and Security

LithiumBank's 2021 brine samples were collected via a brine access agreement between LithiumBank and the Petro-company. LithiumBank collected brine samples from 4 oil and gas wells that produce petroleum – and brine – from the Leduc Formation aquifer underlying the Boardwalk Property. The sample collection included both 1-litre assay samples for geochemical determination, and bulk quantities of brine for mineral processing test work. A total of 44 assay samples and 80 m^3 of bulk brine were collected from four oil and gas wells.

11.1 Sample Collection, Preparation and Security

The brine assay and bulk brine samples were collected from suspended wells that were reopened for the sole purpose of collecting Leduc Formation brine on behalf of LithiumBank. The well reopening described in Section 9.1 ensured that the flowing brine was representative of the Leduc Formation brine. Once the flow of representative Leduc Formation brine was confirmed, the brine was piped from the wellhead to a storage vessel/tank.

The assay brine samples were collected from sample nipple points located along the pipe that connected the flow of brine from the wellhead to storage vessel. The assay brine samples were collected in one-litre, plastic, screw top sample bottles, or jugs. The sample jug was secured by screwing the top on tightly and wrapping electrical tape around the screw top. The sample jug was labelled using black permanent marker and laboratory prepared one-sided sticky sample labels. The top lid of the jug was also labelled in permanent marker. The brine samples for assay test work were not filtered, and acid was not added to the sample during the sample collection procedure.

QA-QC samples including sample duplicates, blank sample standards, and lab-prepared semi-certified Li-brine standard samples were inserted randomly into the sample stream for those samples collected at CNRL STURLKS 9-26-68-22. In addition, the QP collected pre- and post-H_2S mitigation samples to test whether the H_2S removal process influences the lithium content of the brine.

The brine assay samples were collected by either the QP, or petrochemical technicians from AGAT Laboratories from Grande Prairie, AB. Brine assay samples were directed to AGAT Laboratories in Calgary, AB through their satellite Grande Prairie office. Brine assay samples analyzed at Bureau Veritas were taken directly to the lab by the QP. Chain of custody of the brine assay samples was provided to, and reviewed by, the QP.

Four 20 m^3 bulk brine samples were collected from each of the four wells for mineral processing. The brine was collected into the on-site brine storage tank. Once 20 m^3 of brine was collected from the well, the brine was pumped into a vented tanker truck for transport to Amgas' facility in Beaverlodge, AB for H_2S mitigation. The sweetened brine samples were stored at Amgas in a locked storage yard. The mineral processing brine samples were shipped by Amgas to the respective commercial laboratories for mineral extraction test work.

11.2 Analytical Procedures

AGAT Laboratories and Bureau Veritas are independent of LithiumBank and are known and reputable laboratories within the energy petrochemical sector. AGAT is accredited to ISO/IEC 17025 by the Canadian Association for Laboratory Accreditation Inc. (CALA) and/or Standards Council of Canada (SCC). Bureau Veritas is accredited to ASTM: American Society for Testing and Materials ISO/IEC 17025: 2017 General Requirements for the Competence of Testing and Calibration Laboratories.

The laboratories performed the following analytical techniques on the brine samples:

- Routine water analysis for cations and anions, measured and calculated total dissolved solids (TDS), observed pH, relative density, resistivity, salinity, and total alkalinity as $CaCO_3$.
- At AGAT, a total of 27 metallic elements were analyzed as total metals by ICP-OES after an acid digestion procedure. Reported elements include aluminum, antimony, arsenic, barium, beryllium, bismuth, boron, cadmium, calcium, chromium, cobalt, copper, iron, lead, lithium, manganese, magnesium, molybdenum, potassium, phosphorous, nickel, selenium, silicon, silver, sodium, strontium, thallium, tin, titanium, uranium, vanadium, and zinc. The minimum limit of detection for lithium at AGAT is 1.0 mg/L Li.
- At Bureau Veritas the metallic analytical results include a suite of 32 metal elements. The analysis was conducted as total metals by Total Acid Digestion for Metals (ASTM D5708) followed by ICP-OES 32 element scan for total metals (EPA SW-846 6010C).
- The analytical procedures followed nitric acid digestion (SM 3030 E), Metals by Plasma Emission Spectroscopy, Inductively Coupled Plasma (ICP) Method (SM 3120 B), Procedure for Spectrochemical Determination of Total Recoverable Metals (EPA 200.2), and ICP-mass spectrometry (EPA 6020A).
- The Total Organic Carbon analyses were conducted at AGAT Laboratories using method the SM 5310 B combustion-infrared method. A portion of the brine is injected into a heated reaction chamber (900°C) and packed with an oxidant catalyst such as cobalt oxide. The CO_2 produced by the oxidation of carbon is transported into a non-dispersive IR analyser. TOC is determined by the difference of total carbon minus inorganic carbon. The minimum limit of detection is 100 mg/L.

11.3 Quality Assurance – Quality Control

The QA-QC sampling at CNRL STURLKS 9-26-68-22 is summarized in Figure 11.1 and discussed in the text that follows. Figure 11.1 shows that the QA-QC protocol included:

- Original samples (pre-H_2S mitigation) = 6 samples.
- Duplicate samples (pre- H_2S mitigation) = 5 samples.
- Original samples (post- H_2S mitigation) = 4 samples.
- Duplicate samples (post- H_2S mitigation) = 3 samples.
- Blank standard samples, which contained no lithium = 5 samples.

- Lab-prepared semi-certified Li-brine standard samples = 3 samples.

Sample ID	Laboratory	Sample type	Sample prep (H_2S)	Total Li (mg/L)
RE21-LB-SL-001	AGAT	Original	Un-mitigated brine	72.7
RE21-LB-SL-002	AGAT	Lab-prepared standard	/	222.00
RE21-LB-SL-003	AGAT	Duplicate of previous original	Un-mitigated brine	69.7
RE21-LB-SL-004	AGAT	Blank sample	/	<0.02
RE21-LB-SL-005	AGAT	Original	Mitigated at AmGas	71.8
RE21-LB-SL-006	AGAT	Duplicate of previous original	Mitigated at AmGas	76.0
RE21-LB-SL-007	Bureau Veritas	Original	Un-mitigated brine	57.2
RE21-LB-SL-008	Bureau Veritas	Duplicate of previous original	Un-mitigated brine	57.4
RE21-LB-SL-009	Bureau Veritas	Blank sample	/	0
RE21-LB-SL-010	Bureau Veritas	Lab-prepared standard	/	202
RE21-LB-SL-011	AGAT	Original	Mitigated at AmGas	75.4
RE21-LB-SL-012	AGAT	Duplicate of previous original	Mitigated at AmGas	75.4
RE21-LB-SL-013	AGAT	Lab-prepared standard	/	218.00
RE21-LB-SL-014	AGAT	Original	Un-mitigated brine	72.2
RE21-LB-SL-015	AGAT	Duplicate of previous original	Un-mitigated brine	68.8
RE21-LB-SL-016	AGAT	Original	Mitigated at AmGas	73.4
RE21-LB-SL-017	AGAT	Blank sample	/	<0.02
RE21-LB-SL-018	AGAT	Duplicate of previous original	Mitigated at AmGas	81.9
RE21-LB-SL-019	Bureau Veritas	Blank sample	/	0
RE21-LB-SL-020	AGAT	Original	Un-mitigated brine	68.8
RE21-LB-SL-021	AGAT	Duplicate of previous original	Un-mitigated brine	73.1
RE21-LB-SL-022	AGAT	Blank sample	/	<0.02
RE21-LB-SL-023	Bureau Veritas	Original	Un-mitigated brine	55.7
RE21-LB-SL-024	Bureau Veritas	Duplicate of previous original	Un-mitigated brine	56.4
RE21-LB-SL-025	Bureau Veritas	Original	Un-mitigated brine	54.9
RE21-LB-SL-026	AGAT	Original	Mitigated at AmGas	74.8

Figure 11.1: Summary of QA-QC samples collected from well CNRL STURLKS 9-26-68-22

11.3.1 Results of Duplicate Samples

A total of eight duplicate brine samples were collected and analyzed at AGAT (n=6) and Bureau Veritas (n=2). The analytical results for the duplicate pairs are presented in Figure 11.2. There is good data quality as depicted by the low RSD% values that range between zero and 7.7% (AGAT) and 0.2% and 0.9% (Bureau Veritas).

Sample ID	Laboratory	Sample type	Sample prep (H_2S)	Total Li (mg/L)
RE21-LB-SL-001	AGAT	Original	Un-mitigated brine	72.7
RE21-LB-SL-003	AGAT	Duplicate	Un-mitigated brine	69.7
			Average	71.20
			Standard deviation	2.12
			RSD%	3.0
RE21-LB-SL-005	AGAT	Original	Mitigated at AmGas	71.8
RE21-LB-SL-006	AGAT	Duplicate	Mitigated at AmGas	76.0
			Average	73.90
			Standard deviation	2.97
			RSD%	4.0
RE21-LB-SL-007	Bureau Veritas	Original	Un-mitigated brine	57.2
RE21-LB-SL-008	Bureau Veritas	Duplicate	Un-mitigated brine	57.4
			Average	57.30
			Standard deviation	0.14
			RSD%	0.2
RE21-LB-SL-011	AGAT	Original	Mitigated at AmGas	75.4
RE21-LB-SL-012	AGAT	Duplicate	Mitigated at AmGas	75.4
			Average	75.40
			Standard deviation	0.00
			RSD%	0.0
RE21-LB-SL-014	AGAT	Original	Un-mitigated brine	72.2
RE21-LB-SL-015	AGAT	Duplicate	Un-mitigated brine	68.8
			Average	70.50
			Standard deviation	2.40
			RSD%	3.4
RE21-LB-SL-016	AGAT	Original	Mitigated at AmGas	73.4
RE21-LB-SL-018	AGAT	Duplicate	Mitigated at AmGas	81.9
			Average	77.65
			Standard deviation	6.01
			RSD%	7.7
RE21-LB-SL-020	AGAT	Original	Un-mitigated brine	68.8
RE21-LB-SL-021	AGAT	Duplicate	Un-mitigated brine	73.1
			Average	70.95
			Standard deviation	3.04
			RSD%	4.3
RE21-LB-SL-023	Bureau Veritas	Original	Un-mitigated brine	55.7
RE21-LB-SL-024	Bureau Veritas	Duplicate	Un-mitigated brine	56.4
			Average	56.05
			Standard deviation	0.49
			RSD%	0.9

Figure 11.2: Comparison of duplicate samples

11.3.2 Results of Sample Blank Samples

Sample Blanks composed of store-bought bottled water were inserted into the sample stream (n=3 samples). The analytical results for all five sample blanks yielded lithium contents that were below the minimum detection. This is an accurate result as the sample standard blank solution contained no lithium.

11.3.3 Results of Lab-Prepared Brine Standard Samples

To further evaluate brine analytical accuracy, a laboratory prepared semi-certified Sample Standard prepared by the University of Alberta was randomly inserted into the sample stream of the 2021 brine sampling program. Components of the LithiumBank's Sample Standard include pre-measured powdered quantities of LiCl, $CaCl_2.2H_2O$, $MgCl_2.6H_2O$, NaCl, KCl, Na_2SO_4, $FeCl_3.6H_2O$, $Na_2SiO_3.9H_2O$ together with 9.8 L MilliQ water; and 0.200 L 70% HNO_3. The Sample Standard has a conceived mean of 206±3 mg/L Li. This value is derived from the University of Alberta using ICP-MS instrumentation after routine calibration of the instrument.

A total of 3 lab-prepared Sample Standard samples were submitted as part of the brine sample stream to AGAT (n=2 samples), Bureau Veritas (n=1 sample). The analytical results ranged between 202 and 222 mg/L Li, which within the analytical error of the University of Alberta CIP-MS measured value. The average of the 3 Sample Standard samples, with the inclusion of the University of Alberta analysis, is 212 mg/L Li.

The RSD% of the Sample Standard analysis is 3.9% indicative of very good data quality and the Sample Standard analytical results from all labs plot within two standard deviations of the mean (195.5 mg/L Li; Figure 11.3).

It is concluded that the laboratories used by LithiumBank are within error of the lab-prepared brine standard and therefore, the analytical data presented are suitable for reporting purposes in this technical report and for use in potential future resource estimation reporting.

11.3.4 Laboratory Check Samples

11.3.4.1 Qualified Person Laboratory Check Samples

Of the 18 original samples collected at well CNRL STURLKS 9-26-68-22, 5 and 13 samples were analyzed at LithiumBank's primary lab (AGAT) and check-lab (Bureau Veritas), respectively. Comparative results are presented in Figure 11.4 and show that the AGAT brine analysis consistently yielded higher lithium results in comparison to the Bureau Veritas results.

A similar trend is apparent in the analytical work conducted at both laboratories on the lab-prepared Sample Standard (Figure 11.3). The reason for this discrepancy is not known and it is recommended that a fully certified Sample Standard for Li-brine be completed via round robin analyses by a Canadian certified reference materials project to test Li-brine testing laboratories.

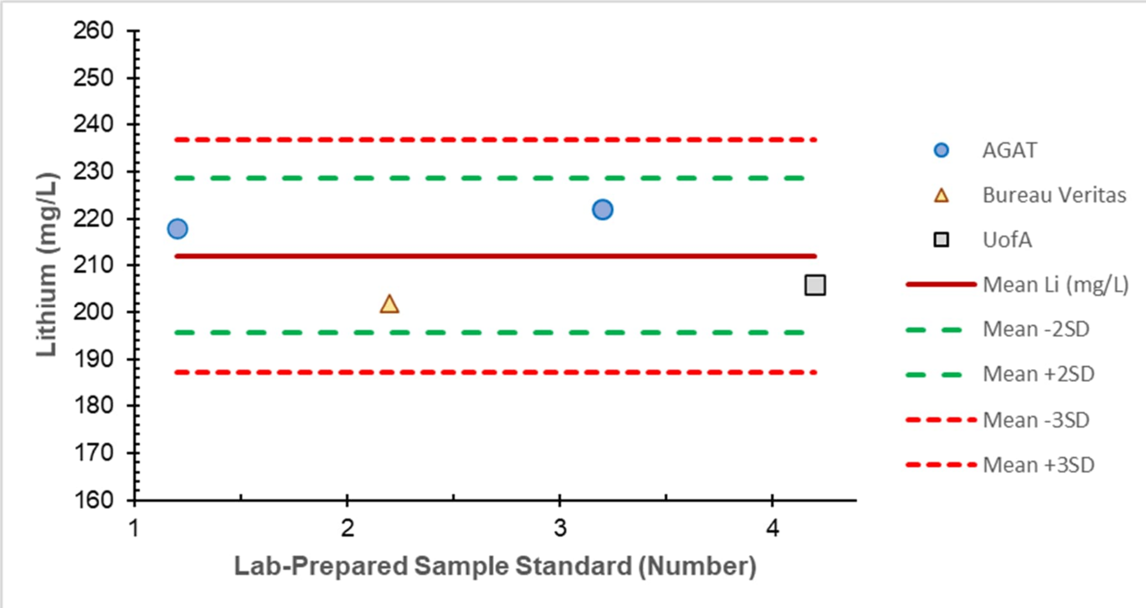


Figure 11.3: Sample Standard analytical results

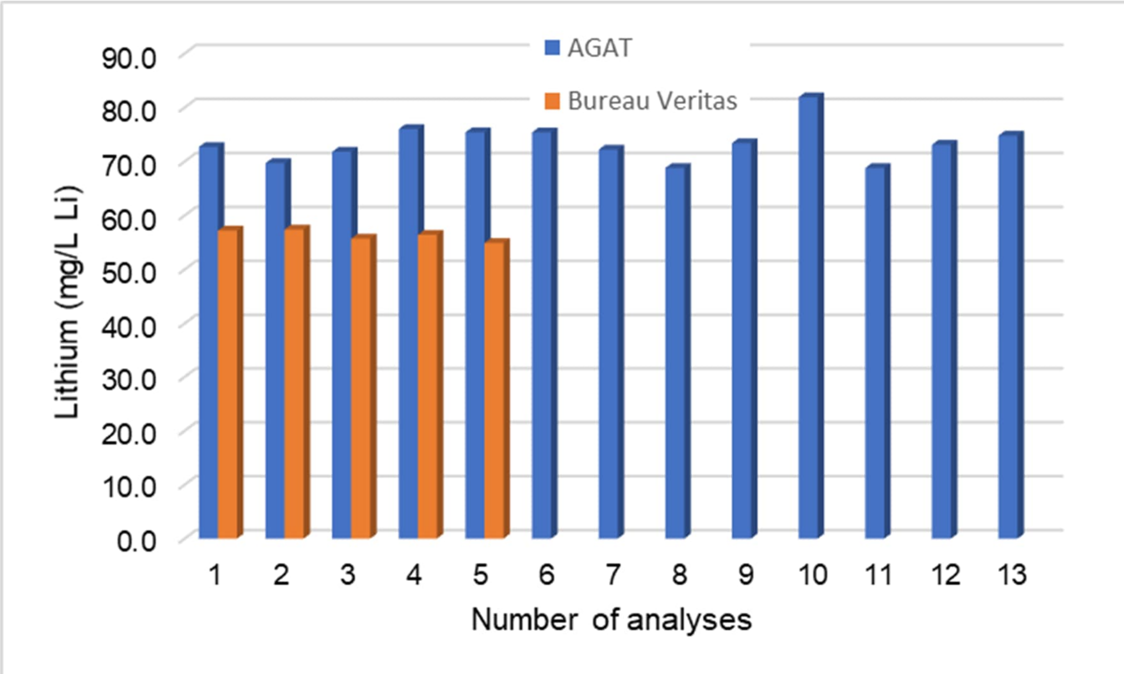


Figure 11.4: Laboratory analytical comparison using brine samples collected from CNRL STURLKS 9-26-68-2

11.3.4.2 LithiumBank Laboratory Check Samples

In December 2021 LithiumBank conducted a laboratory Li-brine analyses check study using a lab-prepared hypersaline sample standard that had a lithium concentration of 72.57 mg/L Li (prepared by Dr. Salman Safari from Recion Technologies Inc., or Recion, of Edmonton, AB). The standard sample had the same lithium concentration as the target Leduc Formation aquifer brine interval to test the calibration range of the ICP machines at various labs in concert with LithiumBank's DLE test work. The brine standard sample was delivered at four certified labs: AGAT Laboratories (AGAT) in Calgary, AB; Bureau Veritas (BV) in Edmonton, AB; Core Laboratories Canada Ltd. (Core Lab) in Calgary, AB, and SGS Canada Inc. (SGS) in Lakefield, ON. The brine standard sample was also sent to two nonaccredited labs including Recion and Conductive Energy Inc. (Conductive) in Calgary, AB. Of the labs used in the brine standard audit test work, it is noted that only AGAT and BV can analyze hypersaline brine that includes hydrocarbons in the sample.

The lithium analytical results from AGAT, Core Lab, SGS, Recion and Conductive are within approximately +/- 10% relative error; BV had approximately -30% relative error (Figure 11.5). As a result of the brine sample standard audit test work, LithiumBank intends to use AGAT Labs as a primary laboratory in their Li-brine assay and analytical testing.

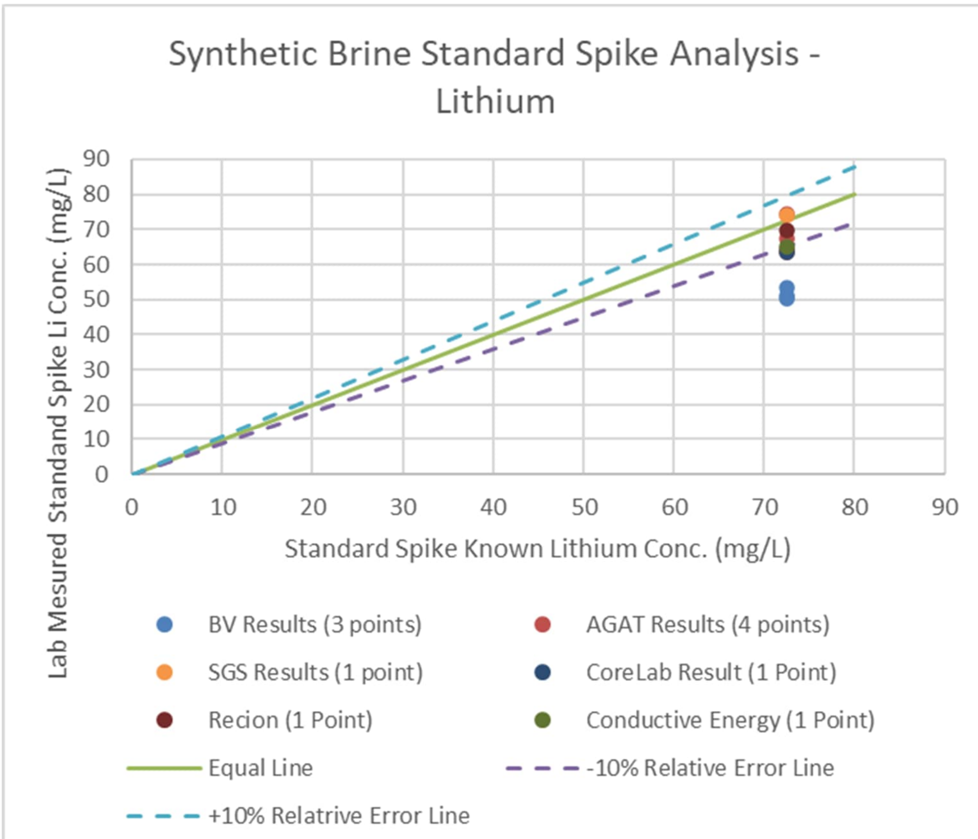


Figure 11.5: Summary of LithiumBank's brine sample standard lithium analytical results

11.3.5 Comparison of Un-Mitigated and Mitigated Brine

Three sets of samples, defined as original and duplicate samples that were collected at the same time interval, were tested prior to, and after H_2S mitigation at AMGAS. In total, 10 brine samples were analyzed at AGAT Laboratories. The purpose of this QA-QC test is to examine if the chemical composition (especially lithium), changes because of the AMGAS mitigation process.

A comparison of un-mitigated versus mitigated geochemical results for selected elements is presented in Figure 11.6. All the selected elements have low RSD% values of 3.6%, 7.5%, and 1.6% (Figure 11.6). It is concluded there is little to no loss of lithium because of the AMGAS H_2S mitigation process, an important conclusion for resource estimation work. However, the H_2S mitigated brine does generally have higher levels of lithium (Figure 11.6). Further work, including knowledge of AMGAS' proprietary H_2S removal is required to explore relationships between lithium, H_2S, and possibly TOC.

Sample ID	Sample prep (H_2S)	Total B (mg/L)	Total Li (mg/L)	Total Sr (mg/L)	Total Ca (mg/L)	Total Mg (mg/L)	Total Na (mg/L)	Total K (mg/L)
RE21-LB-SL-001	Un-mitigated brine	129.00	72.7	927.00	24,800.00	2,730.00	56,500.00	4,140.00
RE21-LB-SL-003	Un-mitigated brine	119.00	69.7	889.00	23,000.00	2,600.00	53,900.00	4,010.00
RE21-LB-SL-005	Mitigated at AmGas	126.00	71.8	939.00	25,100.00	2,680.00	57,200.00	4,160.00
RE21-LB-SL-006	Mitigated at AmGas	130.00	76.0	987.00	26,600.00	2,830.00	60,000.00	4,420.00
	Min	119.00	69.70	889.00	23,000.00	2,600.00	53,900.00	4,010.00
	Max	130.00	76.00	987.00	26,600.00	2,830.00	60,000.00	4,420.00
	Average	126.00	72.55	935.50	24,875.00	2,710.00	56,900.00	4,182.50
	Standard deviation	4.97	2.62	40.41	1,477.33	96.26	2,507.32	171.73
	RSD%	3.9	3.6	4.3	5.9	3.6	4.4	4.1
RE21-LB-SL-014	Un-mitigated brine	130.00	72.2	905.00	23,200.00	2,690.00	54,300.00	4,180.00
RE21-LB-SL-015	Un-mitigated brine	126.00	68.8	876.00	23,900.00	2,560.00	54,500.00	3,990.00
RE21-LB-SL-016	Mitigated at AmGas	128.00	73.4	941.00	25,300.00	2,710.00	57,700.00	4,280.00
RE21-LB-SL-018	Mitigated at AmGas	125.00	81.9	927.00	24,800.00	2,690.00	57,600.00	4,720.00
	Min	125.00	68.80	876.00	23,200.00	2,560.00	54,300.00	3,990.00
	Max	130.00	81.90	941.00	25,300.00	2,710.00	57,700.00	4,720.00
	Average	127.25	74.08	912.25	24,300.00	2,662.50	56,025.00	4,292.50
	Standard deviation	2.22	5.57	28.35	934.52	68.98	1,878.61	309.34
	RSD%	1.7	7.5	3.1	3.8	2.6	3.4	7.2
RE21-LB-SL-021	Un-mitigated brine	129.00	73.1	949.00	25,200.00	2,710.00	57,200.00	4,240.00
RE21-LB-SL-026	Mitigated at AmGas	131.00	74.8	954.00	25,300.00	2,760.00	59,100.00	4,320.00
	Min	129.00	73.10	949.00	25,200.00	2,710.00	57,200.00	4,240.00
	Max	131.00	74.80	954.00	25,300.00	2,760.00	59,100.00	4,320.00
	Average	130.00	73.95	951.50	25,250.00	2,735.00	58,150.00	4,280.00
	Standard deviation	1.41	1.20	3.54	70.71	35.36	1,343.50	56.57
	RSD%	1.1	1.6	0.4	0.3	1.3	2.3	1.3

Figure 11.6: Comparison of 3 sets of un-mitigated versus mitigated brine samples collected from CNRL STURLKS 9-26-68-2. The H2S mitigated samples are highlighted in grey

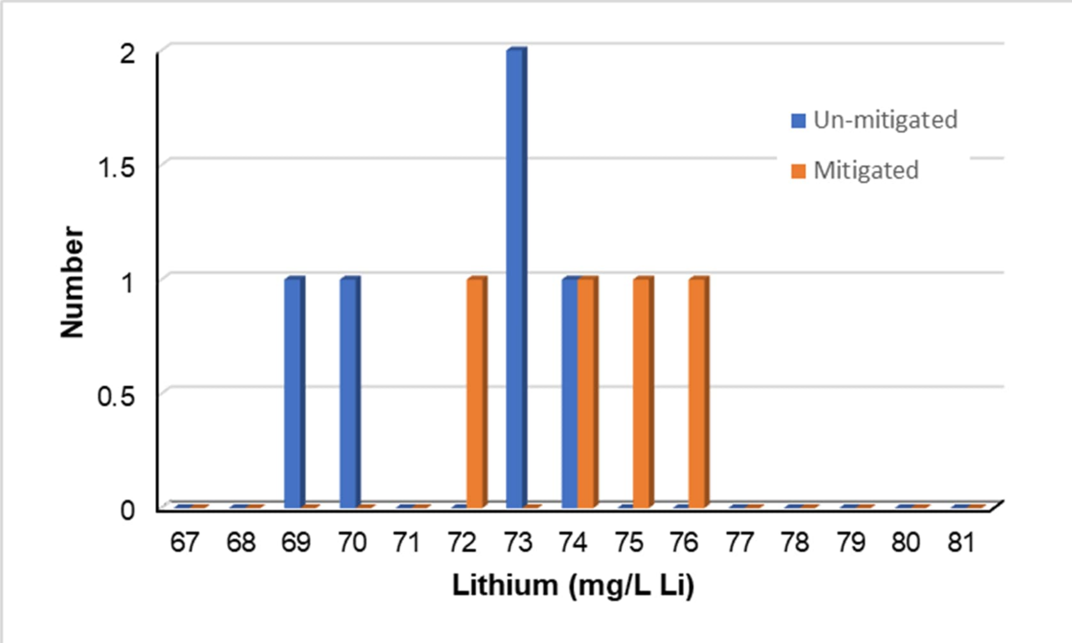


Figure 11.7: Histogram of un-mitigated versus mitigated brine samples from CNRL STURLKS 9-26-68-2

11.3.6 Temporal Assessment of Leduc Formation Brine within the Sturgeon Lake Reef Complex

Historically, the Leduc Formation aquifer brine was sampled from four separate wells during the 2011 Lithium Exploration Group Inc. and the 2016 MGX Minerals Inc. brine sampling programs. The results of these analyses are presented in Figure 11.4 and show there is very little variation; 10% which is within a reasonable range of variance.

UWI	MGX Minerals Inc. (2016) Li (mg/L)	Lithium Exploration Group (2011) Li (mg/L)	Per cent variation
00/08-34-068-22W5	60.7	62.5	3%
00/02-02-069-22W5	60.3	69.6	13%
02/07-19-069-22W5	64.3	71.4	10%
02/16-29-071-23W5	60.5	70.5	14%
Min	**60.3**	**62.5**	**3%**
Max	**64.3**	**71.4**	**14%**
Avg	**61.5**	**68.5**	**10%**

Figure 11.8: Temporal comparison of Leduc Formation aquifer brine analytical results from the same production well

To conduct further temporal assessment, LithiumBank repeated brine sampling completed in 2011 by Lithium Exploration Group Inc. at wells CNRL STURLKS 13-27-68-22 and BARRICK STURLKS 10-6-69-21. A comparison of selected elements between the 2011 and 2021 analytical brine results is presented in Figure 11.9. Brine from CNRL STURLKS 13-27-68-22 has a +19% variation in lithium between the 2011 and 2021 sample programs with the remainder of the elements having between -8% and +24% variation. Brine from BARRICK STURLKS 10-6-69-21 has a -6% variation in lithium between the 2011 and 2021 sample programs with the remainder of the elements having between -9% and +28% variation.

The QP deems this is a reasonable range of variance and to conclude, the elemental comparisons in Figure 11.9 show there is reasonably good temporal homogeneity in the Leduc Formation aquifer brine underlying the Boardwalk Property.

A) Well CNRL STURLKS 13-27-68-22

Year sampled	Company (No. of analyses)	Li (mg/L)	B (mg/L)	Ca (mg/L)	Mg (mg/L)	Na (mg/L)	K (mg/L)
2011	Lithium Exploration Group (n=1 analysis)	61.1	124.0	21,500.0	2,830.0	58,800.0	4,920.0
2021	LithiumBank (n= average of 6 analyses)	72.9	147.0	26,733.0	2,853.0	56,980.0	4,540.0
	Per cent variation	**19.3%**	**18.5%**	**24.3%**	**0.8%**	**-3.1%**	**-7.7%**

B) Well BARRICK STURLKS 10-6-69-21

Year sampled	Company (No. of analyses)	Li (mg/L)	B (mg/L)	Ca (mg/L)	Mg (mg/L)	Na (mg/L)	K (mg/L)
2011	Lithium Exploration Group (n=1 analysis)	74.3	101.0	22,200.0	2,560.0	60,000.0	4,440.0
2021	LithiumBank (n= average of 6 analyses)	69.8	129.0	24,433.0	2,460.0	54,900.0	4,201.0
	Per cent variation	**-6.1%**	**27.7%**	**10.1%**	**-3.9%**	**-8.5%**	**-5.4%**

Figure 11.9: LithiumBank 2021 versus 2011 temporal comparison of Leduc Formation aquifer brine analytical results from the same production wells

11.4 Adequacy of Sample Collection, Preparation, Security and Analytical Procedures

The author and QP has reviewed the adequacy of the sample preparation, security, and analytical procedures and found no significant issues or inconsistencies that would cause one to question the validity of the data associated with the historical work and LithiumBank's 2021 brine sampling program. The work conducted was completed using accepted standard sampling practices, QA-QC protocols, and analytical methods. The analytical brine data were prepared by independent and accredited third-party laboratories and the analytical methods carried out by the laboratories is standard and routine in the field of Li-brine geochemical analytical test work.

The QP is therefore satisfied with the adequacy of the sample preparation, security, and analytical procedures as implemented by LithiumBank and the independent laboratories. It is the QP's opinion that the analytical results produced from these laboratories are sufficient for mineral resource estimation work in accordance with NI 43-101 and CIM Definition Standards and Guidelines (CIM, 2014, 2019).

12. Data Verification

12.1 Qualified Person Site Inspection

The QP conducted the most recent NI 43-101 site inspection at the Boardwalk Property on July 27-29, 2021, in which the QP:

1. Observed the reopening of suspended oil and gas well CNRL STURLKS 9-26-68-2 for the purpose of Leduc Formation brine sampling by LithiumBank.
2. Collected a total of 26 one-litre brine samples from well CNRL STURLKS 9-26-68-2 for assay and QA-QC testing and maintained the chain of custody of the samples from the field to the laboratories.

The samples were analyzed at AGAT and Bureau Veritas; independent labs that routinely process high TDS brine and perform trace element analysis for lithium. The labs comply with the data quality objectives of the industry, Canadian Regulators, U.S. EPA, and the International Standards Organization (ISO/IEC 17025). The lithium content (and trace elements) of the brine samples were analyzed by ICP-OES, which is a standard analytical technique and industry standard for the measurement of lithium-in-brine.

A summary of the QP brine sample analytical results is presented in Section 9.1 (see Figure 9.7). The QA-QC measures applied on the Boardwalk Property brine samples is discussed in Section 11.3. The analytical results of the brine samples collected by the QP confirm the Li-brine mineralization of the Leduc Formation aquifer brine underlying the Boardwalk Property. Of the 10 original samples collected by the QP at CNRL STURLKS 9-26-68-2, the lithium value ranges between 54.9 mg/L Li and 75.4 mg/L Li and averages 67.7 mg/L Li.

12.2 Validation of the Lithium-Brine Geochemistry

The QP participated in LithiumBank's 2021 brines sampling program as part of a QP site inspection. The QP collected Leduc Formation brine samples from one of the four wells sampled and maintained chain of custody of these samples from the field to the labs. The QP reviewed the analytical results of brine samples from all four wells and found no discrepancies within the 2021 analytical results. In addition, the QP compared the 2021 analytical results with all historical Leduc Formation Li-brine data from the Boardwalk Property and found the data correlated very well.

Whit respect to historical geochemical data, the fluid geochemical data presented in Section 6.2, Government Lithium-Brine Studies, are from publicly available well fluid data that was analyzed by the original oil and gas companies; the data were submitted to, and is managed by, the Alberta Energy Regulator. These data have been compiled and reported in various Government reports (e.g., Hitchon et al., 1995; Eccles and Jean, 2010; Eccles and Berhane, 2011; Huff et al., 2019). These data were evaluated for robustness and charge imbalances using SOLMINEQ.88 (Kharaka et al., 1988). Any assays with a charge imbalance of >15% were rejected; of the analysis retained, approximately 66% and 23% had a charge imbalance of <5% and 5-10%, respectively. In reviewing the historical Alberta oilfield brine data, the Government authors have published only the culled data using the charge balanced approach. For further review on the data culling, the full details of the manipulations carried out on these historical data can be reviewed in Hitchon (1993).

The historical data in Section 6.2 includes some recent brine geochemical analyses that were conducted in central Alberta by Huff et al. (2019). The independent Government analyses support the lithium values of the larger historical fluid geochemical dataset.

With respect to the industry-collected historical data (Section 6.3), the senior author and QP can verify the water sampling protocol and analytical methods used to collect and analyze these brine samples are reasonable and standard practice for Li-brine exploration in deep-seated, confined aquifers. The senior author and QP has been involved with independent validation of the Li-brine data at the Boardwalk Property since 2010 as an employee of the Alberta Geological Survey and as an independent QP and consultant.

12.3 Validation of the Leduc Formation Reef Aquifer Dimensions

With respect to the construction of the 3-D geological model of the Leduc Formation aquifer, the authors did not verify all horizon picks associated with the 814 and 462 wells used to grid the top and base of the Leduc Formation. The QP conducted approximately 30 spot checks to compare the horizon picks obtained in Accumap or GeoVista against the picks make on the geophysical e-logs. A very high percentage of the Leduc Formation picks were reasonable accurate. Our investigation included checks on anomalous outlier picks, and if the reason for the anomaly could not be resolved using available data, the pick was removed from the database.

The 3-D geological model of the Leduc Formation reef created as part of the resource estimation process was compared to the Leduc reef outline as published in the Alberta Geological Surveys 3D provincial geological framework model of Alberta (Alberta Geological Survey, 2019). The comparison, which is presented in Figure 12.1, shows the two models are similar and support the 3-D model used in the resource estimate presented in this Technical Report.

12.4 Validation of the Leduc Formation Hydrogeology

Government reports and data from third-party oil and gas well databases were used to assess the hydrogeology of the Leduc Formation aquifer at LithiumBank's Boardwalk Property. Mr. Touw compared these data with HCL's internal hydrogeology database that includes limited regional information for hydraulic parameters of the individual aquifers and chemical quality of formation water at depth. No discrepancies were observed. In addition, the number of core measurements, drill stem tests, pressure surveys, and fluid measurements for the Leduc Formation aquifer underlying the Boardwalk Property was sufficient to complete a reasonable, initial hydrogeological assessment of the Sturgeon Lake Oilfield reservoir as presented in this Technical Report.

12.5 Validation Limitations

The QPs are reliant on historical oil and gas well data, including formation top horizon picks, core measurements, drill stem test data, etc. Consequently, a potential limitation of the data discussed in this report is the age in which the information was generated (ca. 1950's to 2000's). Despite this, several government and academic authors have utilized the same information for the facies and structural interpretations of the Sturgeon Reef Complex and adjacent strata (e.g., Switzer et al., 1994; Stoakes and Campbell, 1996; Skilliter, 2000; Wendte and Uyeno, 2005). Nevertheless, it is possible that new drilling and/or core work using modern analytical approaches and tools could generate new information that could further the hydrogeological and resource estimation parameters included in this Technical Report.

12.6 Opinion of Qualified Person on the Adequacy of the Data

The senior author and QP has reviewed the adequacy of the exploration information, including geochemical data and well formation top/base data, and the visual, physical, and geological characteristics of the property and found no significant issues or inconsistencies that would cause one to question the validity of the data. The QP is satisfied to include the exploration data including wells litho-logs and sample assays for the purpose of resource modelling, evaluation and estimations as presented in this report.

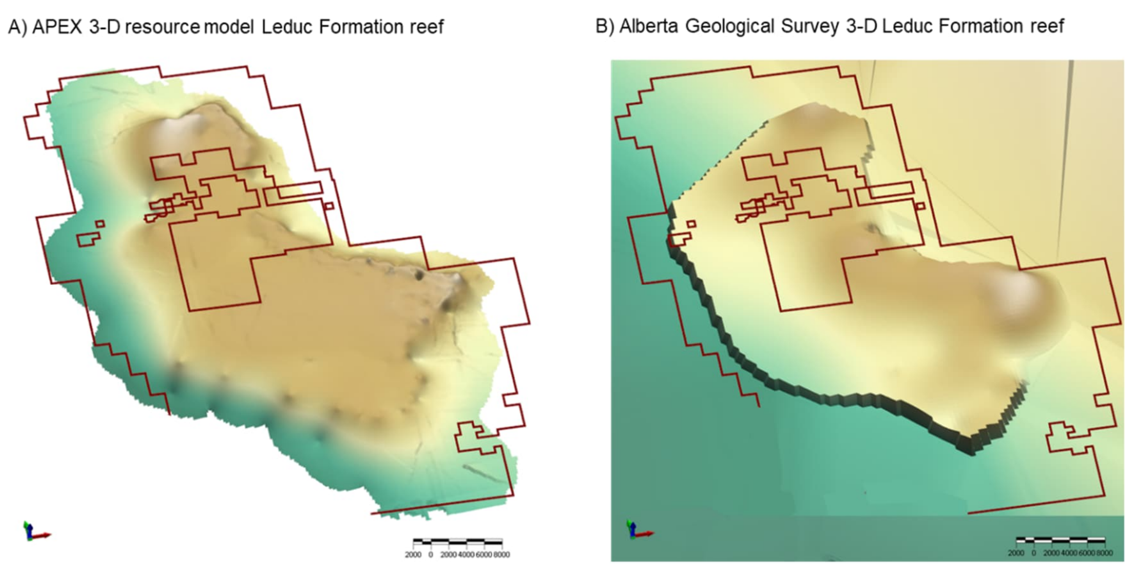


Figure 12.1: Comparison of the 3-D geological outline of the Leduc Formation Sturgeon Lake Reef Complex between the resource model used in this report and an Alberta Government basin model. Vertical exaggeration is 15x

13. Mineral Processing and Metallurgical Testing

13.1 Introduction

Go2Lithium Inc. ("Go2Lithium") was retained by LithiumBank Corp. ("LithiumBank") to conduct bench-scale lithium recovery test work using the Go2Lithium DLE technology. The test work campaign aims to understand the equilibrium and kinetic properties of the DLE sorbent during the interaction with the brine sample and to define the critical process and engineering parameters to design and operate a pilot plant to selectively extract lithium from the brine and produce a concentrated and partially purified eluate.

The DLE test work program lasted twelve months at the Go2Lithium lab facility from August 2022 to August 2023, using real and synthetic brine samples.

13.2 Brine Sample Preparation and Characterization

The brine sample that was used in this part of the test work was sampled from Well 100/09-26-068-22WS/OO by LithiumBank. The brine source sample was cooled to the ambient temperature and stored prior to any pretreatment. The dissolved H_2S was removed by AMGAS to be less than 1 mg/L, and subsequently, Swirltex's technology was adopted to remove the total suspended solids (TSS) and total petroleum hydrocarbon (TPH) to be less than 1 mg/L. Two samples of pretreated brine (8 L and 50 L) were sent by LithiumBank to the Go2Lithium laboratory facility for sampling, characterization, and testing.

13.3 Brine DLE Process

The test work campaign as of November 2023 is summarized below. Brine sample SL-9/26-AM-D2-SW was used for the adsorption isotherm tests and brine sample SL-9/26-AM-DR-SW-011-10 was used for all other tests. Both brine samples were provided to Go2Lithium after removal of H_2S, TSS and TPH, as described in Section 13.2

13.3.1 Loading

Equilibrium adsorption isotherms were generated in a stirred reactor using real brine which was heated to control temperature, with pH controlled at 6.6±0.1 by addition of alkali. Two isotherms were obtained using sodium hydroxide for pH control, at 50°C and 70°C, and one using lime for pH control, at 70°C (**Figure 13.1**). Adsorption kinetics were measured at 70°C and pH 6.6±0.1 (**Figure 13.2** and **Figure 13.3**).

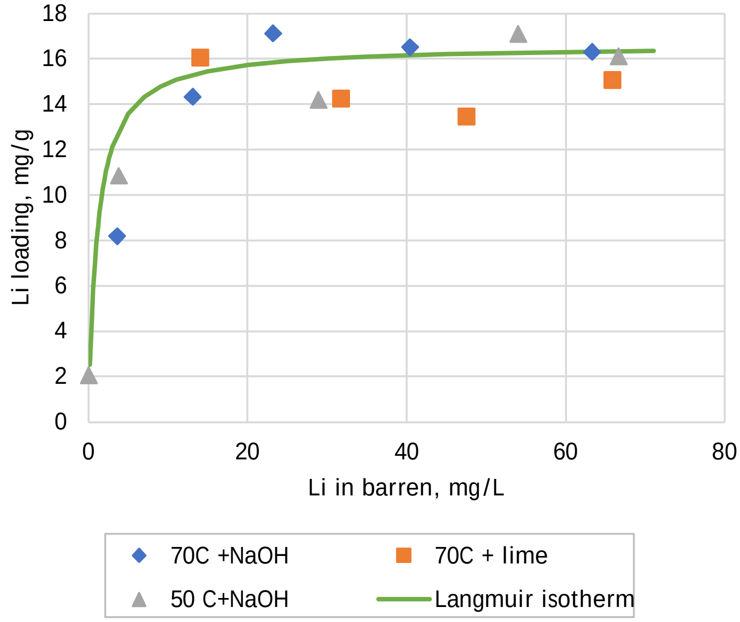


Figure 13.1: Lithium equilibrium adsorption isotherms

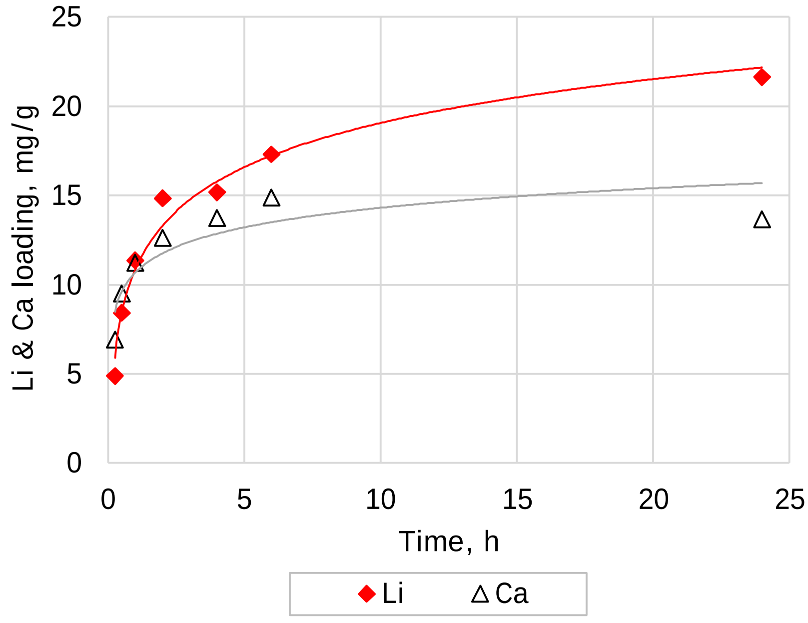


Figure 13.2: Rate of lithium and calcium adsorption from feed brine (70°C)

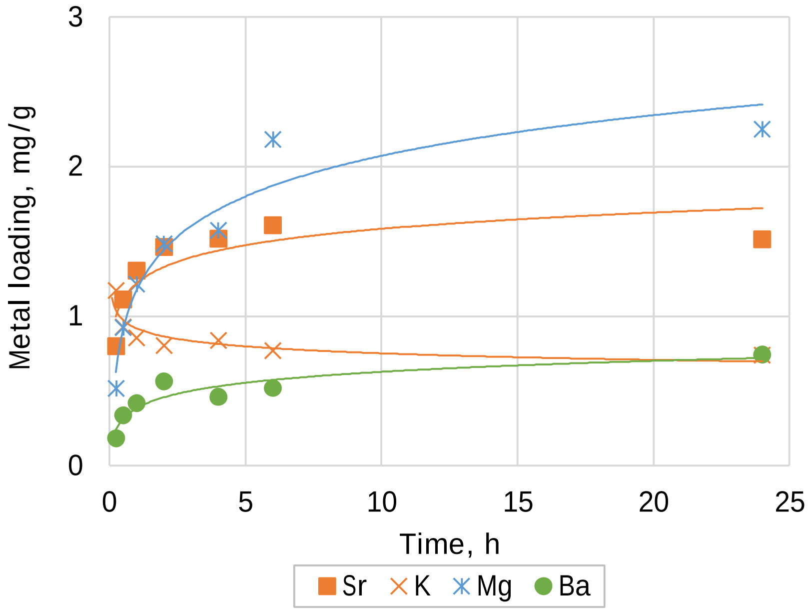


Figure 13.3: Rate of strontium, potassium, magnesium, and barium adsorption from feed brine (70°C)

The key findings for adsorption are as follows:

1. Near complete (99%+) lithium extraction can be achieved at a loading of ~16.1 mg/g.
2. The major co-loaded element was calcium.
3. There was a negligible difference in lithium loading at 50 and 70°C.
4. The use of lime instead of sodium hydroxide did not adversely affect lithium loading or recovery.
5. Maximum loading of calcium, magnesium and strontium was achieved within the first 6 hours; lithium loading continued to increase after 6 hours and was 20% higher at 24 hours. Based on the equilibrium and kinetic tests, two theoretical adsorption stages are sufficient to extract over 98% of lithium from a brine containing 70 mg/L of lithium in a counter-current process with pH control, and that a barren sorbent containing 2.3 mg/g residual lithium can produce a lithium depleted brine containing less than 1 mg/L lithium.

13.3.2 Elution

Lithium-loaded sorbent was prepared and washed to remove entrained brine. The washed lithium-loaded sorbent was then mixed with water and then sulfuric acid was slowly added to bring the pH down to 1.5 while stirring. During acid addition, a white precipitate (alkaline earth sulfates) formed. Once the pH had stabilized, the slurry was mixed by rolling for 15 hours. The liquor was recovered and used for further contacts with lithium-loaded sorbent to generate the elution isotherm (**Figure 13.4**). Separation of the sorbent from the precipitate was straightforward, as was separation of the precipitate from the liquor by filtration.

Elution kinetics (**Figure 13.5**) were measured by contacting portions of lithium-loaded sorbent with pH 1.5 sulfuric acid solution for various periods of time (up to 24 hours) at ambient temperature (approximately 20°C). The mixtures were stirred and the pH was maintained at 1.5 by addition of sulfuric acid.

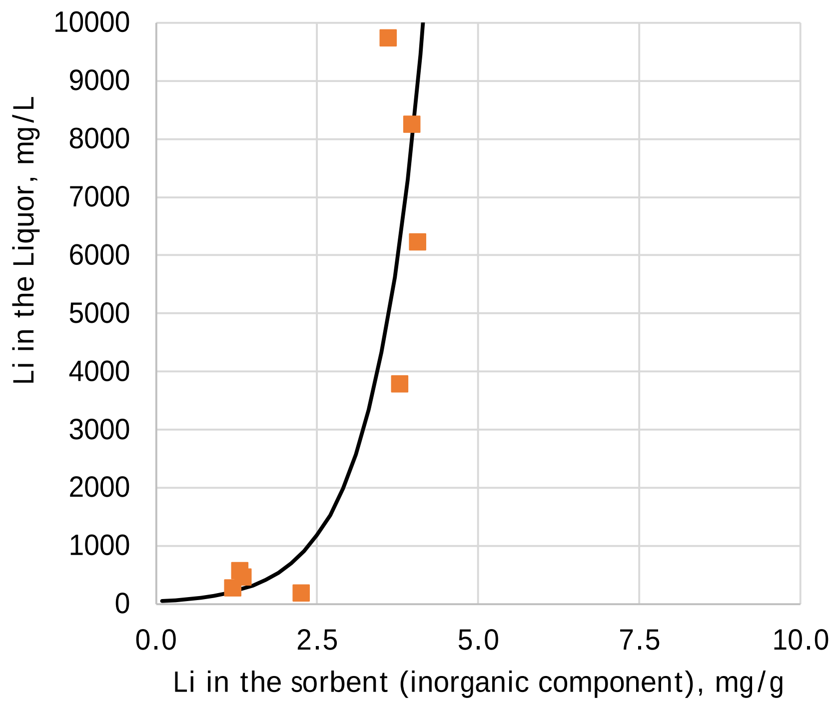


Figure 13.4: Lithium elution isotherm (pH 1.5, sulfuric acid)

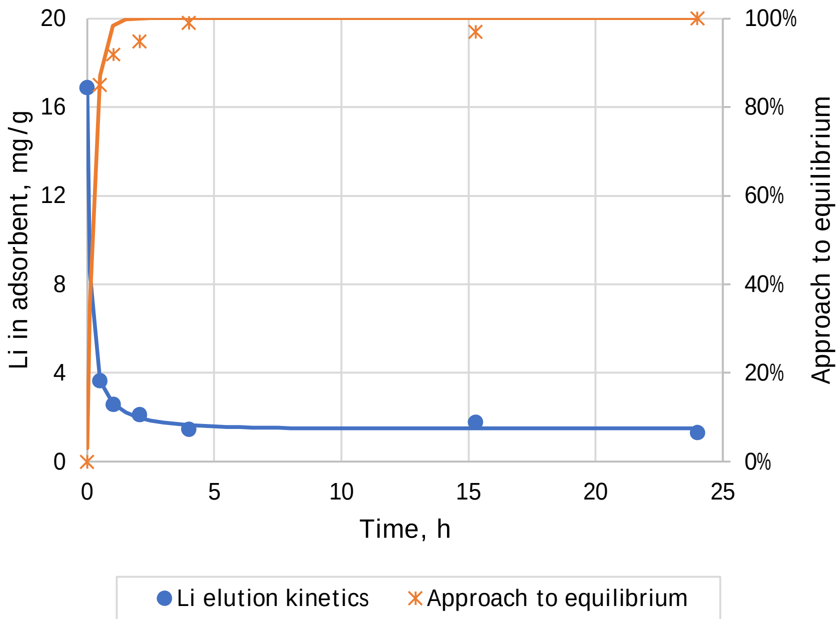


Figure 13.5: Lithium elution kinetics (pH 1.5, sulfuric acid)

The key findings for elution are as follows:

1. Based on the elution isotherm, an eluate containing over 8 g/L lithium can be produced, which reduces the flow for downstream treatment.
2. An average residual lithium content of 1.5 mg/g (approximately 10% of the initial loading) was demonstrated.
3. By using sulfuric acid for elution, over 90% of co-loaded calcium and strontium were precipitated, and close to 100% of co-loaded barium, resulting in a lithium:calcium mass ratio of 25:1 in the eluate, compared to 1.4:1 in the lithium-loaded sorbent.
4. The major impurities remaining in the eluate were magnesium, sodium and residual calcium.
5. More than 90% of equilibrium elution was achieved within one hour and the sorbent fully equilibrated with the elution solution in under 5 hours. On average, a residual lithium concentration of ~1.5 mg/g was achieved.

13.4 Quality Assurance/Quality Control (QA/QC) for Test Work Campaign

All elemental analysis for the test work completed by Go2Lithium was carried out by HRL Technology Group Pty Ltd (located in Melbourne, Australia), a NATA-accredited laboratory under ISO/IEC 17025, using a SPECTRO ARCOS ICP-OES instrument. The same synthetic brine sample used above was analyzed by HRL, and by using the standard addition approach, the measured lithium concentration agreed with that reported by the other laboratories (Table 13-1).

The control sample was individually sampled five times and identically diluted (15x). Samples were read on the ICP-OES instrument six times each (30 times in total) and gave an average response with a relative standard deviation of the readings for lithium, sodium, potassium and scandium (internal standard) of ~0.3%.

Aliquots of the diluted control sample were individually spiked with lithium standard to contain additional 1, 2, 3, 4, 5 and 6 mg/L lithium, respectively. Each spiked sample was measured six times and the average intensity relative to potassium, sodium, calcium and scandium (two lines) to lithium was plotted vs lithium standard addition as shown in Figure 13.6. All the extrapolated curves converged at 4.29 mg/L (64.4 mg/L after accounting for 15x dilution factor).

Table 13-1: Comparison of HRL analysis of synthetic brine sample to Canadian laboratories

Element	Canadian labs	HRL
B	0	0.07
Ba	0	0.3
Ca	24633 ± 1438	23700
Fe	0	0.1
K	4403 ± 143	4260
Li	62.21 ± 8.1	64.6
Mg	2491 ± 181	2430
Mn	0	<0.032
Na	61703 ± 4284	58700
S	0	2.47
Si	0	<0.1
Sr	998 ± 51	900
Ti	0	<0.03

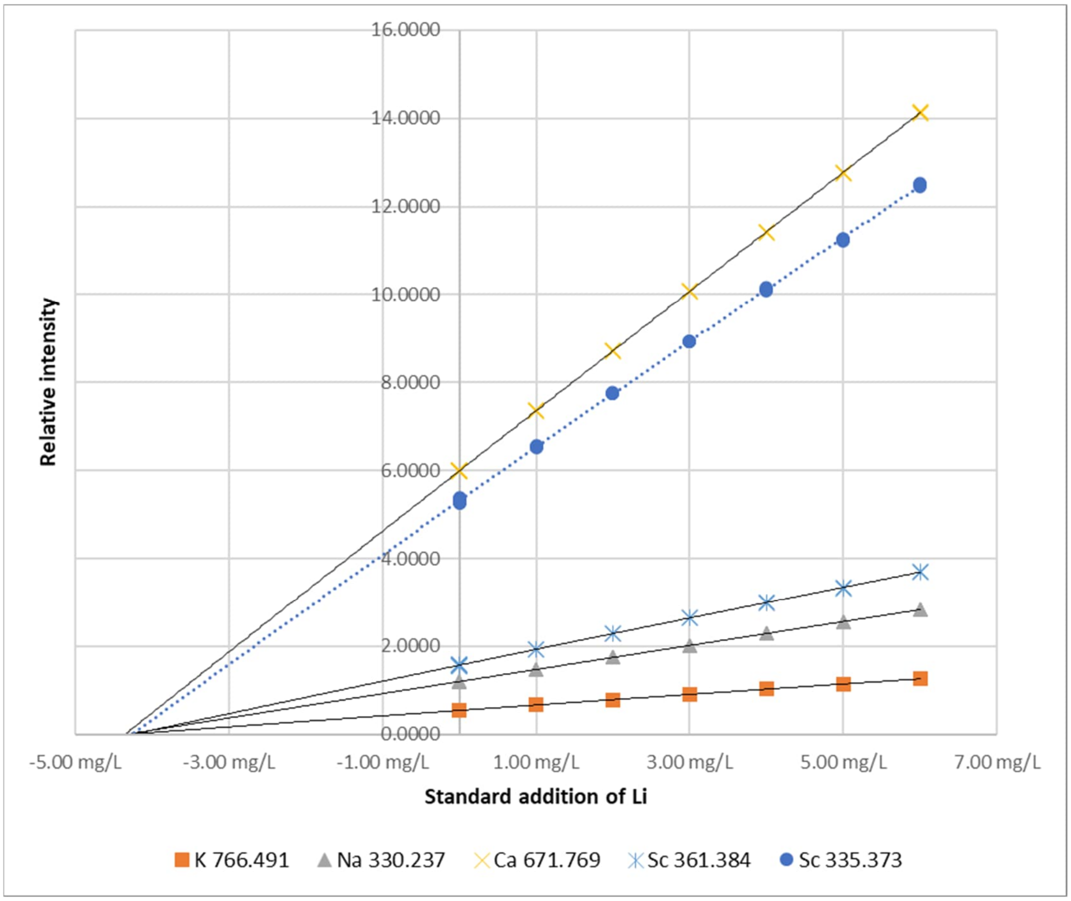


Figure 13.6: Measurements from the standard addition calibration at HRL Technology Group (lithium spikes added to 15x diluted synthetic brine)

Further evaluation of the instrument response established that a 50x dilution of the brine sample with external calibration gave comparable results to the standard addition approach, and subsequent brine samples were analyzed using this simpler method. Non-brine samples (e.g. eluates) contained high lithium concentrations and required larger dilutions to bring the lithium concentration in the range of the instrument, rendering matrix effects less significant. External calibration was adequate for these high lithium samples, using custom calibration standards. The custom standards were prepared from solutions certified by an ISO 17034-accredited laboratory, except for those containing high sodium, for which the sodium component was prepared from high-purity sodium chloride.

The instrument was re-calibrated for each set of samples from the DLE testing. Duplicates were analyzed every tenth sample as an internal QA/QC check. A synthetic control sample and/or LithiumBank feed brine was included with every sample batch to assess the analysis quality (see Table 13-2).

Table 13-2: Replicate measurements of control samples from different analytical runs

Control sample	Lithium (mg/L)
Synthetic control	65.0
	64.6
	65.0
Average	64.9
Standard deviation	0.4%
LithiumBank brine	65.0
	63.8
	66.0
	61.0
	64.8
Average	64.1
Standard deviation	3%

Each sample was diluted 5, 50, and 500 times. Each dilution was prepared from the original samples, not by serial dilution, and analyzed in order of highest to lowest dilution factor, to minimize memory effects. The results were calculated for all three dilutions and cross-checked.

13.5 Conclusions

LithiumBank commissioned the scoping test work program to establish the selective lithium extraction performance metrics of the Go2Lithium DLE technology, and to develop a good understanding of the process conditions and equipment to generate lithium concentrates that are suitable for further treatment to produce battery grade lithium products. The first stage of the work has been completed at Go2Lithium's lab facility, which entails the bench scale of tests on the equilibrium and kinetic properties of the DLE sorbent for loading and elution. It is shown that the DLE sorbent that was utilized in this test program demonstrated the capability to selectively extract lithium from LithiumBank's feed brine and produce a lithium concentrate suitable for downstream production of lithium chemicals. Mixed contactors in a counter-current configuration enable the use of low-cost lime slurry for pH control in adsorption, and for low-cost sulfuric acid in elution, which provides further rejection of co-loaded calcium, strontium, and barium as solid precipitates as shown in Table 13-3.

Table 13-3: Recovery to loaded sorbent and eluate

Element	Recovery (Feed to Loaded Sorbent)	Recovery (Feed to Eluate)
Ba	27%	<0.005%
Ca	<0.5%	<0.1%
K	<0.1%	<0.1%
Li	98.6%	98.6%
Mg	<0.5%	<0.5%
Na	<0.01%	<0.01%
Sr	<1%	<0.05%

The data gathered based on the test work was used to guide engineering and optimize the process conditions to develop the DLE process basis for the Preliminary Economic Assessment (PEA) technical report.

The information based on the bench scale test work will provide critical inputs to define the design parameters for next phase pilot plant development. During this future phase of test work, it is proposed to confirm the process design conditions with consideration of variables such as sorbent-to-fluid ratio, pH, and temperature. It is also recommended that testing seeks to understand the impact of sorbent residence time and contactor staging on recovery, and the longevity of the DLE sorbent.

To date, the current program of laboratory scale studies has been used to determine the process design criteria and equipment configuration for an automated 200-500 L/h DLE pilot plant, incorporating adsorption, loaded sorbent wash, elution, and eluted sorbent wash, to further evaluate the long term performance of the DLE process at scale.

13.6 Comments on Section 13

13.6.1 Go2Lithium DLE

The QP notes:

- The loading and elution kinetics have been investigated in this phase of testwork, including the application of alternate neutralizing/pH control reagents including caustic and lime.
- Overall DLE recoveries of over 98% for lithium (brine to eluate) and significantly increased solution lithium concentrations have been achieved.
- Significantly decreased impurity content of eluate, over 99% rejection of calcium, potassium, sodium, magnesium, barium, strontium (brine to eluate).
- The testwork undertaken for the loading and elution sections in the process flowsheet are sufficient for the purposes of the preliminary economic scoping study.
- It is recognized further work is required going forwards and this is addressed in subsequent sections.

14. Mineral Resource Estimates

14.1 Introduction and Resource Estimation Steps

LithiumBank's Boardwalk Li-Brine Project is an early-stage exploration project. Stratigraphically, the resource area is confined to the subsurface, confined Devonian Leduc Formation aquifer underlying the Property. More specifically, the outline of the Sturgeon Lake Reef Complex was used to define the mineral resource estimation areas.

Two separate resource areas are presented as shown in Figure 14.1 and include:

1. An indicated resource area defined by the outline of the Sturgeon Lake South Oilfield within the Sturgeon Lake Reef Complex.
2. An inferred resource area that incorporates all the remaining Sturgeon Lake Reef Complex area outside of the Sturgeon Lake South Oilfield (i.e., outside of the indicated resource area).

Statistical analysis, three-dimensional (3-D) modeling and resource estimation was prepared by Mr. Black, M.Sc. P. Geo. of APEX. The modeling and estimation work were performed in direct collaboration and supervision of Mr. Eccles, M.Sc. P. Geol. who takes responsibility for the resource estimation presented in this Technical Report. The workflow implemented for the calculation of the Boardwalk lithium-brine resource estimation was completed using: the commercial mine planning software MicroMine (v 20.5).

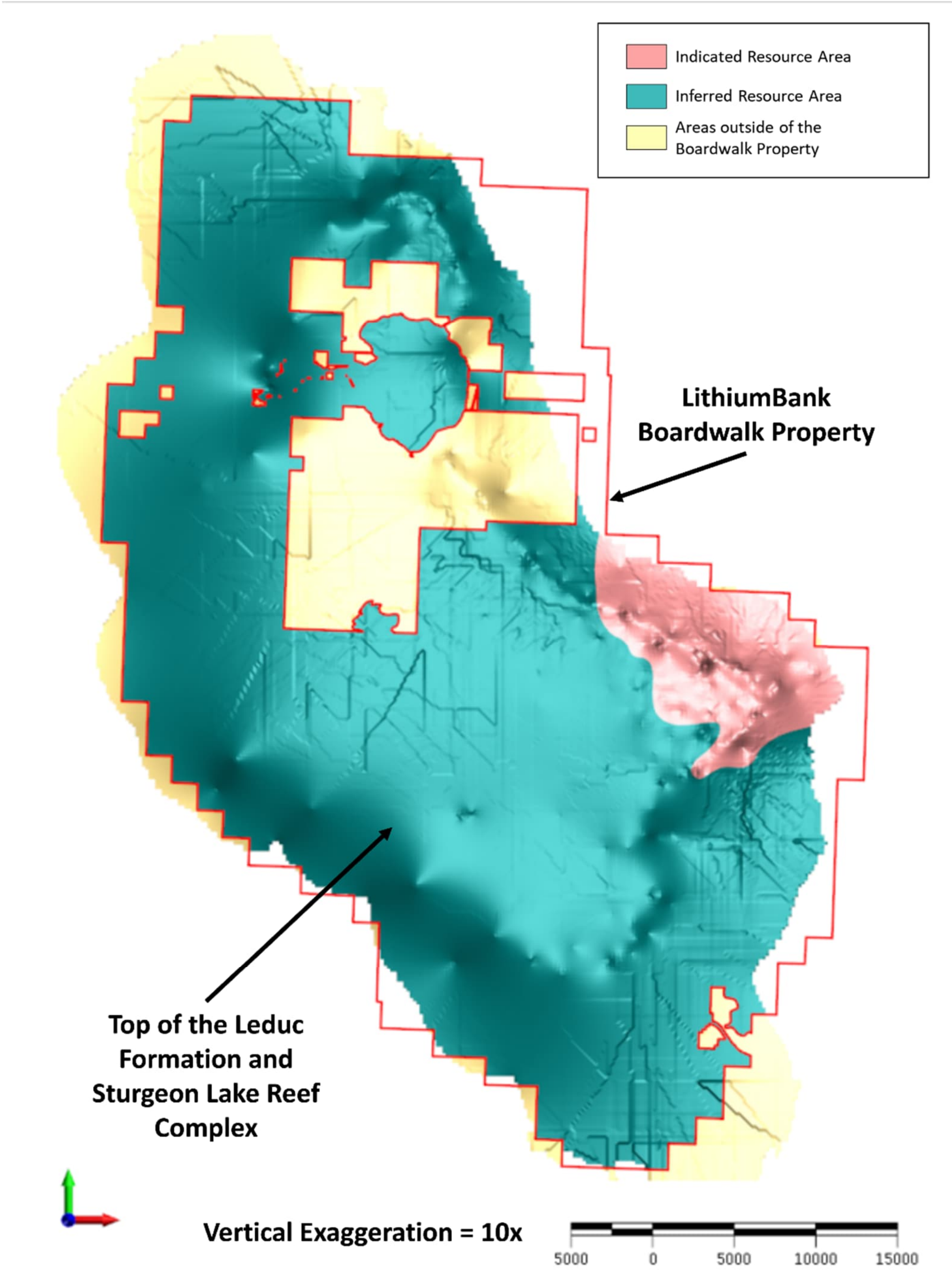


Figure 14.1: Three-dimensional image of the Leduc Formation and Sturgeon Lake Reef Complex in relation to the Boardwalk Property with the outline of the indicated (pink) and inferred (green) resource areas. The yellow areas represent Provincial Park or First Nation lands that have been removed from the resource estimation process. The Sturgeon Lake Reef Complex (and resource areas) have also been clipped to the margins of the Property.

Critical steps in the determination of the LithiumBank Li-brine resource estimation include:

- Definition of the geology, geometry, and pore space volume of the subsurface Devonian Leduc Formation domain aquifer underlying the Boardwalk Property.
- Determination of the Li-brine concentration in the Leduc Formation domain aquifer.
- Demonstration of reasonable prospects of eventual economic extraction.
- Estimate of the *in-situ* lithium resources of Leduc Formation aquifer brine underlying the Boardwalk Property using the relation:
    - Lithium Resource = Total Volume of the Brine-Bearing Aquifer X Average Effective Porosity X Percentage of Brine in Pore Space x Average Concentration of Lithium in the Brine.

The Boardwalk Li-brine Resource Estimate is reported in accordance with CIM definition standards and best practice guidelines (2019, 2014) and the disclosure rule NI 43-101. Mineral resources are not mineral reserves and do not have demonstrated economic viability. There is no guarantee that all or any part of the mineral resource will be converted into a mineral reserve.

The Li-brine resources is also reported in compliance with the CIM Best Practice Guidelines for Resource and Reserve Estimation for Lithium Brine (1 November 2012). The CIM (2012) guideline provides specific criteria for Li-brine modeling and estimation that include definition of the aquifer boundaries; brine chemistry; and depiction of the hydrology of the brine aquifer. The authors have considered all criteria of the CIM Best Practice for Resource and Reserve Estimation for Lithium Brine and used professional judgement in applying them to a ‘confined’ subsurface aquifer.

Previously, LithiumBank disclosed indicated and inferred Boardwalk Li-brine resource estimates with an Effective Date of 20 December 2022. This Preliminary Economic Assessment scoping study, which now represents LithiumBank’s current technical report, includes revised indicated and inferred mineral resources due to a recent change in the outline of LithiumBank’s Boardwalk Property contiguous mineral permits (see Section 4). Reconciliation of the previous and current mineral resource estimations is discussed at the end of this section.

14.2 Data

14.2.1 Subsurface Hydrogeological and Geological Model

Hydrogeological characterization of the Leduc Formation aquifer at LithiumBank’s Boardwalk Property, and Sturgeon Lake Oilfield reservoir, has been acquired from a variety of public and proprietary sources that include:

- Government reports and information from the Alberta Energy Regulator (AER) databases, Alberta Geological Survey reports, and the Alberta Environment and Parks (AEP) water well information database that describe the regional geologic framework, a description of regional lithologies, and the extent of geologic units (e.g., Prior et al., 2013; Alberta Geological Survey, 2021).

- Data compiled by the Alberta Energy Regulator that is distributed by third-party oil and gas well databases such as geoSCOUT, GeoVista, and Accumap, which contain stratigraphic data (picks and wireline logs), drill stem test data (pressure, temperature, and water quality information), core plug data (pressure and porosity information), and historical measurements of fluid production and injection rates.

The stratigraphic tops, bottoms and lateral extents of formations defined by Hydrogeological Consultants Ltd. (2018, 2022), with emphasis on the Devonian Leduc, Beaverhill Lake, and Ireton units, were used to create a 3-D geological model and define the boundaries of the Leduc Formation aquifer (see Section 14.4). The database includes 4,130 total records that is divided into 2,322 records from the AEP Groundwater Centre Database and 1,808 petroleum well records from the AER database.

This information was used to model the subsurface underlying the Boardwalk Property with emphasis on the Devonian Leduc, Beaverhill Lake, and Elk Point (Watt Mountain) stratigraphic units. Figure 14.2 summarizes the number of picks, and their data source, that were used to determine the tops of the stratigraphic formations.

	Source	Total No. of Picks	No. Removed
Leduc	GeoVista	318	8
	Accumap	502	12
Beaverhill Lake	GeoVista	159	12
	Accumap	214	16
	HCL	105	10
Elk Point	GeoVista	12	2
	Accumap	119	2
	HCL	11	2

Figure 14.2: Summary of picks used to model the Leduc, Beaverhill Lake, and Elk Point (Watt Mountain) stratigraphic units

Calculations of fluid yields from Leduc Formation relied on three main components:

1. Determination of aquifer parameters that include, for example, aquifer thickness, total and effective porosity, permeabilities from core data and drill stem tests, hydraulic conductivity, transmissivity, specific storage and storativity.

2. The review and analysis of historic fluid production and injection reported by oil and gas companies to the AER.

3. An estimate of the hydraulic head in the Leduc Formation underlying the Boardwalk Property. Transmissivity values are based on the effective permeability values determined from the quantitative analysis of drill stem tests (DSTs) conducted by Melange Geoscience Inc. (2022). Fluid levels are based on formation pressures.

With respect to the percentage of brine within the Leduc Formation pore space, the most recent three years of fluid production data was evaluated (n=157 records). In this case, the most recent available data was from 2008 to the end of 2010.

14.2.2 Lithium Analytical Data

Li-brine assay data pertinent to calculating an average lithium values that were used in the resource estimations include the analytical results of a July-August 2021 LithiumBank brine sampling program along with historical analytical data results from Government of Alberta reports (Eccles and Jean, 2010; Eccles and Berhane, 2011; Huff, 2016, 2019; Huff et al., 2011, 20212, 2019) and exploration industry company reports (Lithium Exploration Group, 2016; MGX Minerals Inc., 2016).

14.2.3 Data QA/QC

The Leduc Formation horizon pick dataset at the Boardwalk Property was validated by comparing the outline of the Sturgeon Lake Reef Complex with the GoA's three-dimensional geological framework of Alberta (version 3). The comparison of the models correlated well, which added confidence to the 3D geological model created by the senior author and QP of this technical report.

A QP site inspection and data validation allowed the author to verify the mineralization, geochemistry, and geological interpretations in support of the mineral resource estimations. The verification of the oil and gas well data by QPs have shown the data to be reliable and reasonably accurate for mineral resource estimation work. Results of the independent analytical test work conducted by the QP demonstrate that the lithium assay dataset is valid and appropriate to be used in resource estimation.

The QP therefore considers that the data presented and discussed in this report are adequate for the estimation of mineral resources in accordance with CIM definition standards and best practice guidelines (2014, 2019) and the disclosure rule NI 43-101.

14.3 Hydrogeological Characterization of the Leduc Formation Aquifer

This sub-section has been prepared by Hydrogeological Consultants Ltd. (HCL) of Edmonton, Alberta. HCL is independent of LithiumBank, specializes in groundwater and surface water consulting services, and has been commissioned by two previous Li-brine exploration companies that have shown interest in lithium-enriched Devonian aquifer brine underlying the Boardwalk Property (Hydrogeological Consultants Ltd., 2012, 2018).

The hydrogeological characterization study of the Upper Devonian Period Leduc Formation was based largely on data collected from the petroleum industry during the exploration and production of the Sturgeon Lake South oilfield. The area of hydrogeological study at the Boardwalk Property was a 7×7 township area which comprises Townships 066 to 072, Ranges 20 to 26, West of the Fifth Meridian.

As per CIM Best Practice Guidelines for Li-Brine Resources (1 November 2012), the intent of this subsection is to provide an understanding of the hydrology of the brine, and the water balance of the aquifer and the brine itself, for the proper evaluation of a Li-brine resource. It is important that hydrostratigraphic characteristics of a confined aquifer such as porosity, permeability, fluid production and injection, apparent transmissivity, storativity, long-term yield, and formation water modeling be discussed to enable the preparation of brine resource estimates.

14.3.1 Porosity

Characterization of the Leduc Formation porosity is based on several independent sources of information: historically published values (Hitchon et al. 1995), core plug measurements from third-party sources, and wireline logs. The following paragraphs discuss the sources of porosity data and provide a porosity value considered representative of the project.

Hitchon et al. (1995) documented the Leduc North zone, which is equivalent to the Leduc Formation reservoir at the Boardwalk Property, to be approximately 12 m thick with an average porosity of 6%.

Historical effective porosity measurements on core plugs were accessed from GeoVista. A total of 99 effective porosity core plug measurements were reviewed from the Leduc Formation within the Boardwalk Property. The core plugs suggest the Leduc Formation has an average porosity of 5.3% with a geomean of 5.0% (Figure 14.3). Isaaks and Srivastava (1989) consider the average porosity to be a better representation of Formation porosity than the geomean.

	Calculated Porosity (%)		No. of
Geounit	Average	Geomean	Cores
Leduc	5.3%	5.0%	99

Figure 14.3: Summary of effective porosity as measured from Leduc Formation core plugs from the Sturgeon Lake Oilfield

Three downhole well logs were selected within the Boardwalk Property as a means of comparing the core plug effective porosity with total porosity acquired from a variety of petrophysical wireline curves (e-logs; Figure 14.4). The well logs were also used to assess total porosity vertically within the Leduc Formation.

	E-Log Curve					
Well Location (W5M)	Deep Induction Resistivity	Delta Transit Time (Sonic)	Dual Induction Gamma Ray	Neutron Porosity - Sandstone and Limestone	Neutron	Spontaneous Potential
11-10-069-22		x			x	
13-03-069-21	x	x		x		x
07-33-068-21		x	x	x		

Figure 14.4: A summary of the electric-log curve data for three downhole well logs

An analysis of the selected well e-logs was conducted to determine total porosity. Calculations of total porosity from the delta transit time (sonic) curve were based on the Wyllie et al. (1956) time-average equation:

$$\Phi = \frac{(\Delta t - \Delta t_{ma})}{(\Delta t_f - \Delta t_{ma})}$$

Where: Φ = porosity

Δt = transit time from sonic log
Δt_f = 620 µsec/metre for fresh mud
Δt_{ma} = 155.8 µsec/metre for limestone, 142.7 µsec/metre for dolomite and 182.1 µsec/metre for quartz.

Figure 14.3 shows the calculated total porosity associated with the interval between 2,603 and 2,785 m KB in the 11-10-069-22 W5M well, based on analysis of the delta transit time (sonic) curve for dolomite. Within the interval identified as the Leduc Formation, the sonic curve indicates an average porosity of 5.7%.

Figure 14.3 summarizes the average calculated total porosity of the Leduc Formation from the three wells selected for analysis. The average total porosity from the three sonic curves is 5.4% and the average total porosity from the two neutron porosity curves is 3.5%. The average total porosity from all five curves is 4.7%.

The petrophysical trace for well 07-33-068-21W5 showed a divergence below a depth of approximately 2,808 m KB, which indicates the dolomite unit identified in the upper part of the Leduc Formation terminates at this depth. If the porosity values deeper than 2,808 m KB are excluded, the average porosity from the sonic curve and the neutron porosity curve is 5.3%. A similar divergence occurs with the curves from the 13-03 well.

The average total porosity for the upper part of the Leduc Formation was calculated from two of the three wells (Figure 14.5). The upper part of the Leduc Formation was not calculated for the 100/11-10-069-22W5 well because the neutron porosity curve was unavailable. Hence, e-logs showed the upper portion of the Leduc Formation show the average total porosity is higher (5.6%) in comparison to the overall Leduc strata (4.7%; Figure 14.5; Figure 14.7). Figure 14.7 shows the locations of the wells from which core data and petrophysical logs were used to determine porosity of the Leduc Formation at the Boardwalk Property.

Based on the sources of porosity data examined, a porosity value of 5.3% is considered representative of the Leduc Formation.

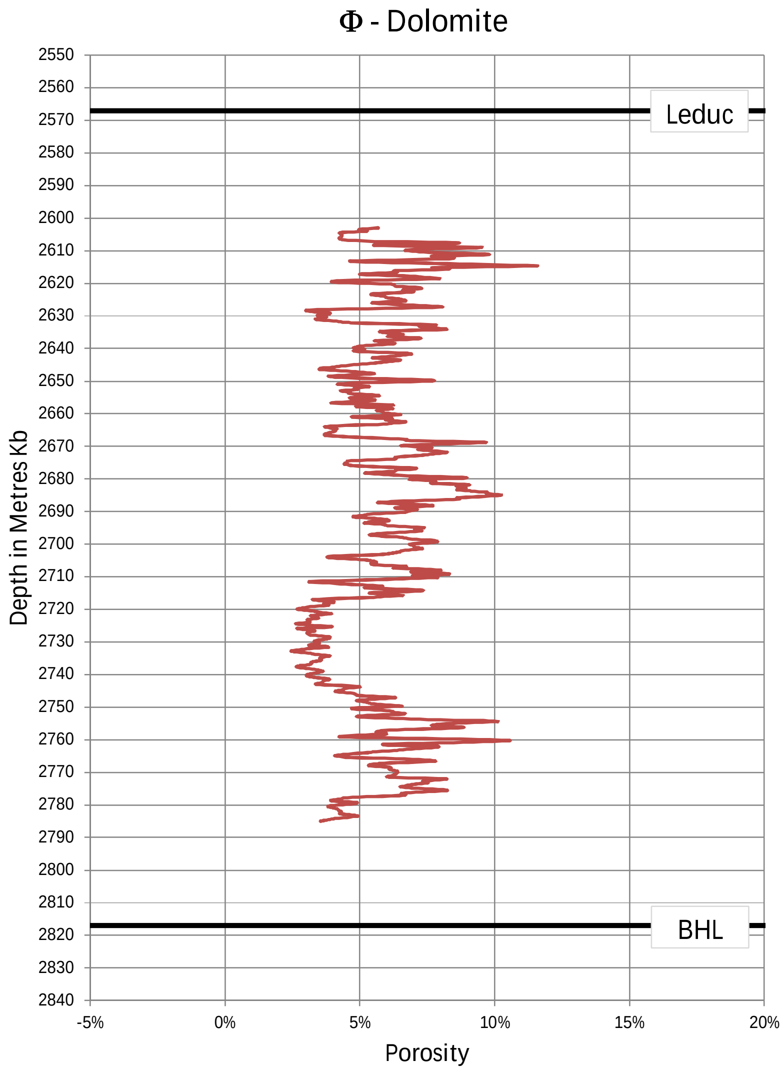


Figure 14.5: Total Leduc porosity using the sonic curve from well 00/11-10-069-22W5

Well Location (W5M)	Average Calculated Porosity (%) – Leduc Formation	Curve*
11-10-069-22	5.7	Sonic
13-03-069-21	5.6	Sonic
	3.0	Neutron Porosity
07-33-068-21	5.0	Sonic
	4.0	Neutron Porosity
Average:	**4.7**	

*Corrected for dolomite

Figure 14.6: Porosity of the Leduc Formation at the Sturgeon Lake Oilfield

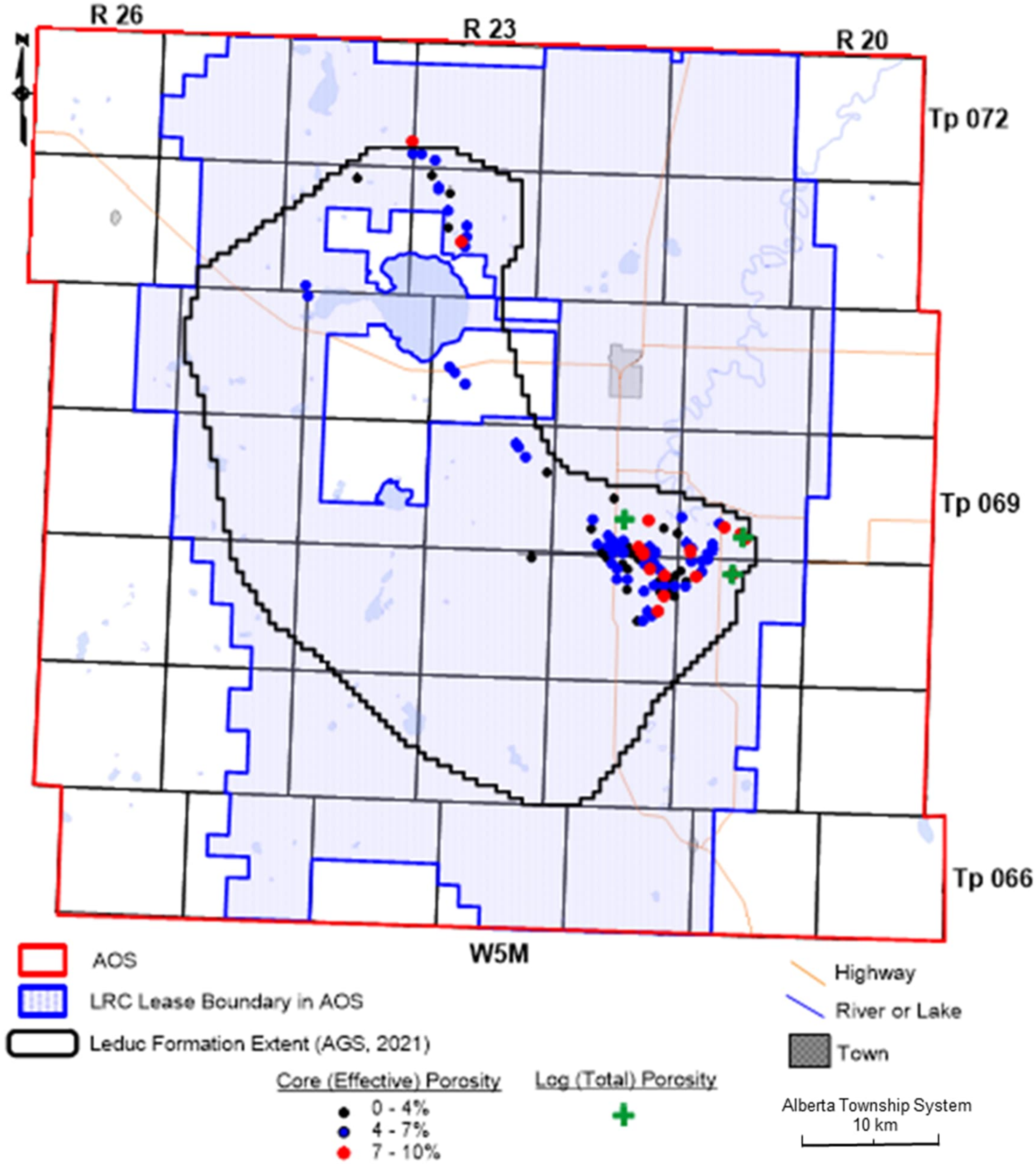


Figure 14.7: Location of well data with effective porosity measurements from core plugs and total porosity from wireline e-logs

14.3.2 Lost Circulation

Lost circulation occurs when drilling fluid flows into one or more geological formations instead of returning up the annulus and can therefore suggest the presence of zones of high permeability. Within the Boardwalk Property, the GeoVista database includes 63 lost circulation occurrences while drilling through the Leduc Formation suggesting the boreholes had intersected zones of high permeability. Of the 63 lost circulation events in the Leduc

Formation, 28 events had a reported lost circulation volume ranging from 4.3 to 288 m^3, and the other 35 events had no reported volumes.

The occurrence of lost circulation in the Leduc Formation is one line of evidence that indicates parts of the Leduc Formation have high permeability.

14.3.3 Permeability

Characterization of the Leduc Formation permeability is based on several independent sources of information: historically published values (Hitchon et al. 1995), core plug measurements, and analysis of DSTs. The following paragraphs discuss each source of permeability data and provide a permeability value considered representative of the Leduc Formation.

Hitchon et al. (1995) documented the Leduc North zone, which is equivalent to the Leduc Formation reservoir at the Boardwalk Property, to be approximately 12 m thick with a permeability of 35 millidarcies (mD).

Core permeability values for the Leduc Formation were determined using the reported Kmax and K90 values from core-analysis results accessed via GeoVista and Accumap. For each of the 99 Leduc Formation wells at the Boardwalk Property, for which there are reported core permeability values, the Kmax and K90 values were averaged for each of the analyzed samples over a given interval. Of the 99 wells from which core samples were analyzed, 91% were in depth intervals within 50 m of the top of the Leduc Formation.

A summary of the core permeability results is shown in Figure 14.8 below. The combined geomean permeability of 140 mD represents the geomean of the averaged Kmax and K90 permeabilities for each core interval. The wide range in calculated core permeabilities suggests a high degree of heterogeneity. The use of geomean permeability is the most representative of a regional scale core permeability value for the Leduc Formation.

	Permeability (mD)										
Average Interval Length (m)	Kmax					K90					Combined Geomean
	Min.	Max.	Average	Geomean	S.D.*	Min.	Max.	Average	Geomean	S.D.*	
16.0	0.84	3,668	603	214	724	0.18	2,742	199	39	440	**140**

* S.D. = standard deviation

Figure 14.8: Core permeability

Melange Geoscience Inc. (2022) analyzed 28 DSTs at the Boardwalk Property for intervals tested in the Leduc Formation, of which 15 DSTs were determined to be suitable for a quantitative analysis to calculate permeability. The tested flow rates ranged from 7 m^3/day to 308 m^3/day.

The equation used by Melange to calculate transmissibility for DSTs that recover primarily liquids is as follows:

$$\frac{Kh}{\mu} = \frac{2149.4Qßo}{m}$$

The value of ßo (fluid formation volume factor) is equal to 1 in DSTs where the analyzed fluid is water, m is the slope of the Horner semi-log straight line in kPa/cycle or psi/cycle, and Q is the flow rate of the recovered fluid during the DST calculated by simple volumetric calculations and flow times. Rearrangement of the above equation to consider the viscosity of water allows the calculation of the permeability thickness:

$$Kh = \frac{2149.4Q\beta o}{m}\ \mu$$

Permeability from DST data (K) is calculated by dividing Kh by h (height), where h is assumed to be the entire tested interval if the porous interval is unknown. If the thickness of porosity within the tested interval is known, a second K value is calculated using the known porous thickness as h.

Figure 14.9 summarizes the permeability results for the Leduc Formation, as calculated from the DST data. The calculated permeabilities (based on the formation water properties described below) range from 3 to 373 mD, with an average of 44 mD and a geomean of 19 mD.

Based on a review of the available permeability data, the DST permeability of 19 mD is considered most representative of the Leduc Formation because the DST analyses test a larger volume of the Leduc than the permeabilities derived from core data.

Location	KB (m)	Top (m)	Base (m)	Tested Interval Thickness (m)	Gauge Depth (m)	Quality Code	Reservoir Pressure P* (kPa)	Hydraulic Head (m AMSL)	Tested Rate (m^3/day)	Permeability (md)
100/08-12-067-23W5	725.1	2,685.0	2,707.0	22.0	2,689.0	B	23,807	462.9	203.6	25
100/06-30-067-23W5	775.6	2,797.0	2,810.0	13.0	2,799.0	B	24,962	521.1	122.9	23
100/11-03-068-22W5	676.5	2,779.0	2,800.0	21.0	2,785.4	A	25,010	440.5	296.5	31
100/06-23-068-22W5	659.8	2,581.9	2,592.0	10.1	2,584.0	A	22,360	355.1	7.1	5
102/04-07-069-21W5	650.0	2,575.0	2,605.0	30.0	2,577.0	A	20,630	176.0	275.8	69
100/01-08-069-22W5	684.4	2,610.0	2,625.9	15.9	2,614.0	A	23,648	481.0	171.9	373
100/09-08-069-22W5	684.9	2,619.1	2,625.2	6.1	2,624.0	D	25,924	703.5	134.4	11
100/15-24-069-23W5	745.4	2,667.0	2,682.0	15.0	2,670.7	A	22,350	353.0	308.4	14
100/13-04-070-23W5	716.9	2,670.0	2,682.2	12.2	2,678.9	B	26,783	768.2	63.6	3
100/05-17-070-23W5	709.9	2,645.7	2,651.8	6.1	2,648.7	A	26,030	714.6	29.5	22
100/08-36-070-25W5	699.5	2,870.0	2,881.0	11.0	2,876.0	A	25,286	401.1	25.8	11
100/04-32-071-23W5	779.2	2,690.0	2,704.0	14.0	2,693.0	B	21,894	318.0	106.3	26
100/07-33-071-23W5	810.5	2,895.0	2,913.9	18.9	2,896.2	A	25,685	532.5	228.7	34
100/02-25-071-24W5	739.1	2,686.8	2,697.5	10.7	2,688.9	A	26,575	759.2	42.0	3
100/06-02-072-24W5	758.0	2,808.0	2,827.0	19.0	2,808.7	B	24,436	440.2	175.3	18
								Average:	146.1	44
								Geomean:	99.3	19

Figure 14.9: Drill stem test permeability

14.3.4 *Hydraulic Conductivity*

Hydraulic conductivity of the Leduc Formation was determined using the representative aquifer permeability and the viscosity (0.5 cP) and density (1.138 g/cm^3) of the brine (http://www.csgnetwork.com/water_density_calculator.html), which results in a conversion factor of 0.001904 metres per day per millidarcy (m/day/mD).

Note: The viscosity of the Leduc brine was determined based on the following: a representative TDS concentration of 200,000 mg/L; a fluid temperature of 82°C (DST data); a formation pressure of 25 MPa; a molality (moles of solute per litre of solution [mol/kg]) of 3.6, based on the full TDS concentration being due to sodium chloride (NaCl); and a fluid density of 1.138 g/cm^3. The dynamic viscosity was estimated using linear interpolation between the two closest tables in Kestin, et al. (1981). For a NaCl brine with a molality of 3.6 mol/kg, the calculated of 0.5 cP is representative of the NaCl brine from the Leduc Formation.

Hydraulic conductivity is calculated by multiplying the aquifer permeability by this conversion factor. The calculated hydraulic conductivity ranges from 0.036 metres per day (m/day) using an aquifer permeability of 19 mD (based on DST data) to 0.27 m/day using an aquifer permeability of 140 mD (based on core data). Because the authors advocate that the drill stem test derived permeability of 19 mD is most representative of the Leduc Formation, a reasonable estimate of the hydraulic conductivity is 0.036 m/day (or 4.2 x 10^{-7} metres per second; m/s).

14.3.5 *Transmissivity*

Transmissivity is determined by multiplying the hydraulic conductivity by the aquifer thickness. Based on a mean aquifer thickness of 206 m, the calculated transmissivity is 7.4 m^2/day.

14.3.6 *Specific Storage and Storativity*

Based on a core porosity of 5.3%, a brine density of 1.138 g/cm^3, a rock compressibility of 3.3 × 10^{-10} m^2/N, and a water compressibility of 4.8 × 10^{-10} m^2/N, the specific storage is estimated to be approximately 4 × 10^{-6} m^{-1} for the Leduc Formation. Based on a mean aquifer thickness of 206 m, the calculated storativity is therefore approximately 8 × 10^{-4}.

14.3.7 *Fluid Production and Injection*

Using completion interval data, some of which has varied over time, production and injection values were assigned to appropriate geounits using surfaces defined by the AGS. Because of uncertainties related to the assignation of a geounit with a particular completion interval in the AER database, no attempt was made to use geounit classifications assigned by the AER data sources.

Reported gas production and injection values were converted to water-volume equivalents, based on a conversion ratio of 0.00514; that is, for every cubic metre of gas produced or injected, 0.00514 m^3 of water-equivalent liquid was assumed to be diverted from the reservoir. This conversion factor is based on a standard temperature of 288.7°K (15°C) and pressure of 100 kilopascals (kPa), and a downhole temperature of 355.2°K 82°C and pressure of 25,200 kPa as shown below:

$$\text{Conversion factor} = \frac{\text{Downhole Temperature}}{\text{Standard Temperature}} \times \frac{\text{Standard Pressure}}{\text{Downhole Pressure}}$$

This conversion approximation was used to facilitate the evaluation of the effects of fluid production on changes to pressure over time. Aquifer pressure was determined from DSTs and converted to freshwater hydraulic head (Figure 14.13).

Reported fluid production from the Leduc Formation at the Boardwalk Property began in 1961. Figure 14.10 shows that average fluid production from the Leduc Formation has generally increased every decade from the 1960s to 2000; since 2000, the annual production rate has been in the order of 3 million m^3/year.

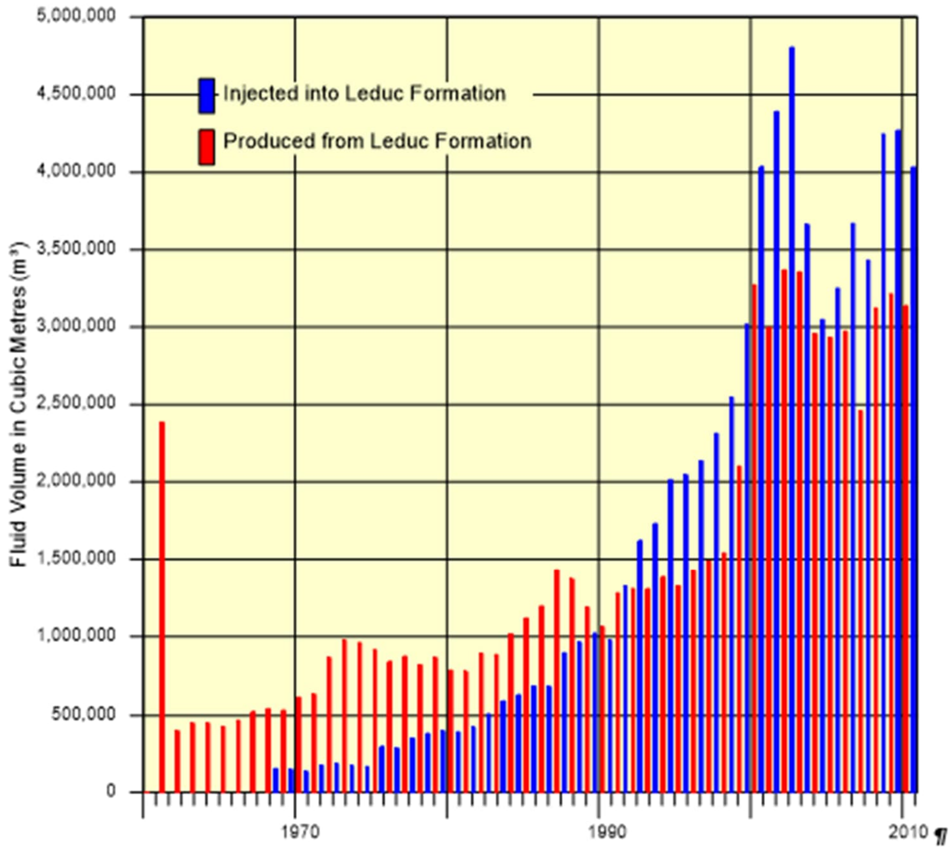


Figure 14.10: Summary of fluid production and injection in the Leduc Formation at the Sturgeon Lake oilfield reservoir between 1960 and 2011

The reported injection rates follow a similar trend to the reported production, although the annual injection has increased at a faster rate, resulting in a situation in which the total injection into the Leduc Formation has been greater than the total production from the Leduc Formation, since 1991. From 2000 through 2010, the average annual injection into the Leduc Formation was 3,894,523 m^3 (10,670 m^3/day), which is nearly 20% more than the liquid volume removed during the same length of time.

A total of 73,178,693 m^3 of liquid was produced from Leduc Formation wells within the Boardwalk Property from 1961 through 2010, of which 72% was reported to be formation water; by comparison, a total of 73,146,659 m^3 of fluid was injected into the Leduc Formation within the Boardwalk Property over the same length of time, representing a difference of less than 1% between net total injected and total produced volumes. Figure 14.11 shows the locations of the Leduc Formation production and injection sites at the Boardwalk Property.

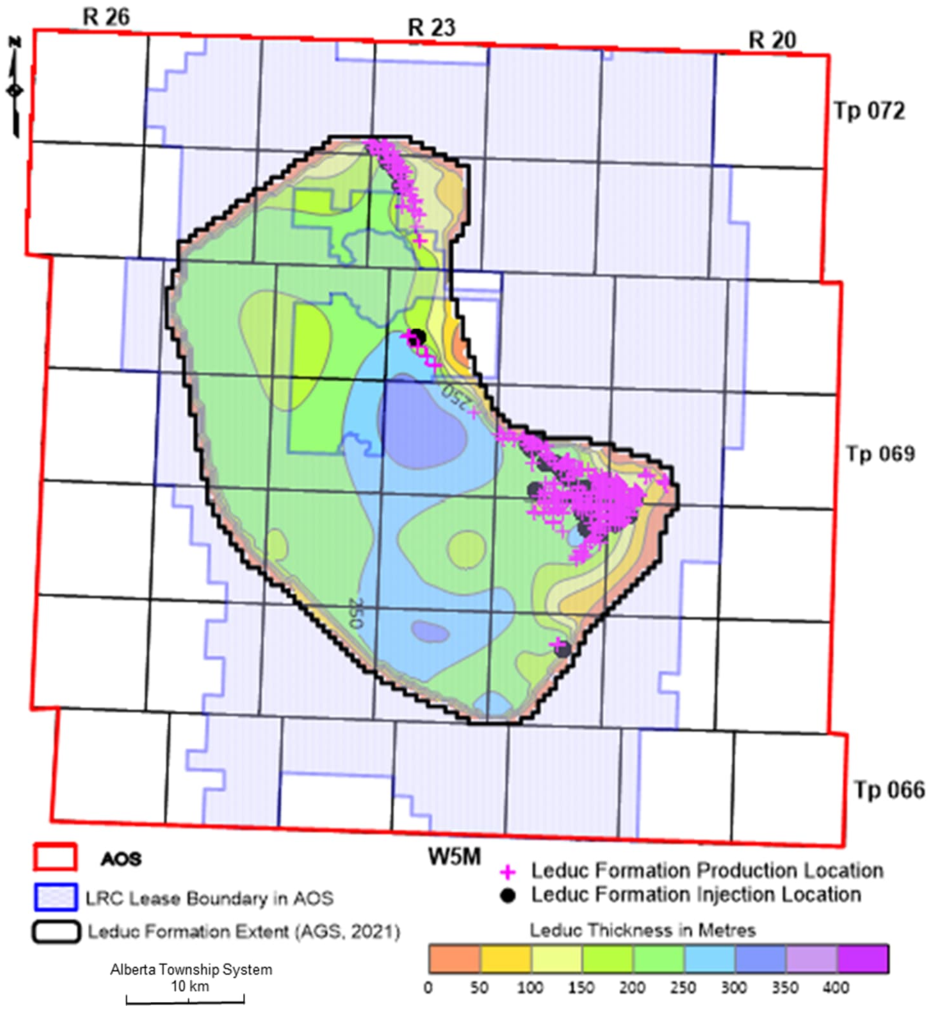


Figure 14.11: Locations of the proposed production and injection sites in the Leduc Formation at the Boardwalk Property

For a 3-year period from 2008-2011, it is estimated that the amount of total fluid (oil, gas converted to reservoir pressure, and brine) and brine produced annually is approximately 11,280,000 m^3 and 11,070,000 m^3, respectively (n=47 wells and 157 fluid production records). Hence, a current estimate of the percentage of brine within the Leduc Formation pore space at Sturgeon Lake is approximately 98%.

Figure 14.12 shows the locations of the Leduc Formation water production sites. The total production refers to the reported volumes of liquids that were produced. Within the Boardwalk Property, there were 146 wells that produced formation water from the Leduc Formation.

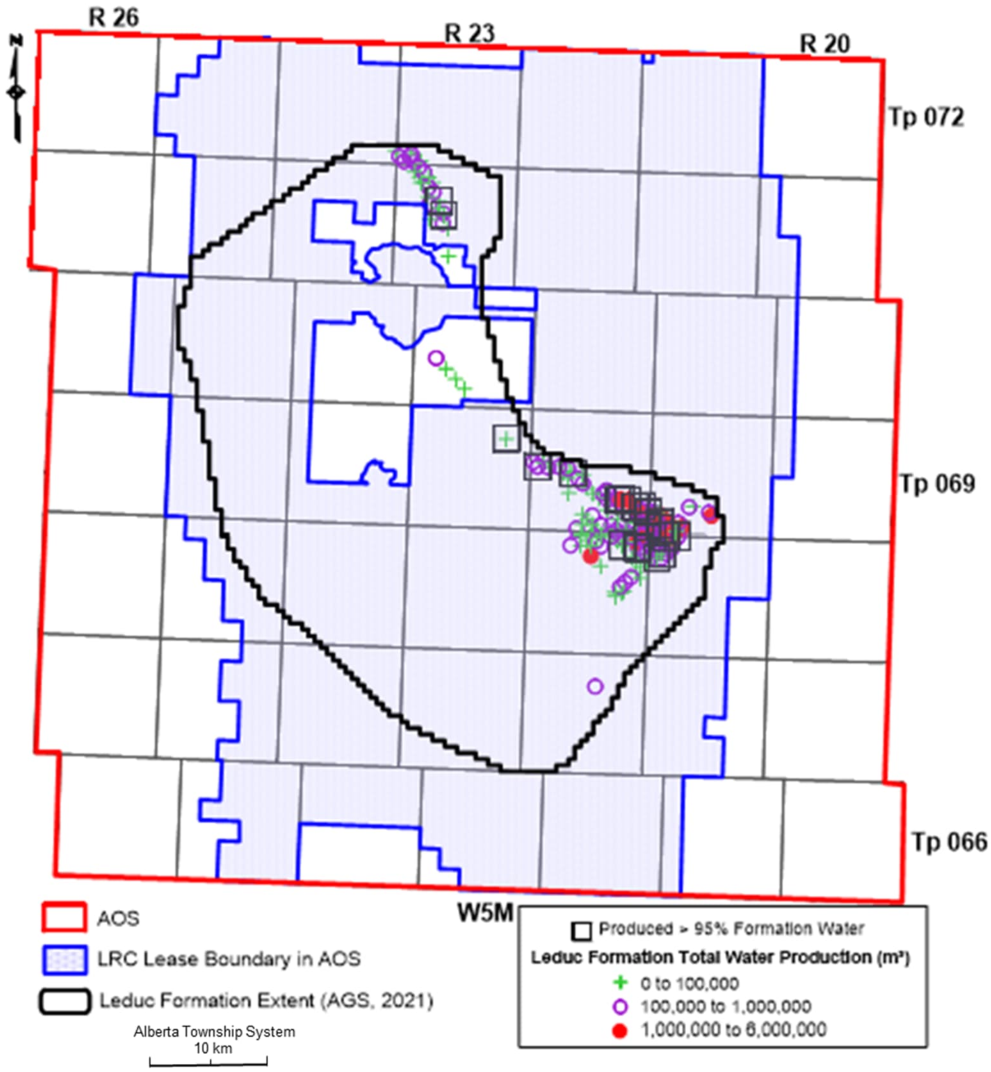


Figure 14.12: Locations of the Leduc Formation water production sites

Of these 146 wells:

- 86 wells produced less than 100,000 m^3, with an average daily formation-water volume of approximately 8 m^3 per well.
- 46 wells produced between 100,000 and 1,000,000 m^3, with an average daily formation-water volume of 46 m^3 per well.
- 14 wells produced more than 1,000,000 m^3, with an average daily formation-water volume of 184 m^3 per well.

Of the 14 Leduc Formation wells that produced more than 1,000,000 m^3, four wells produced liquid that had formation water representing more than 95% of the reported volume: 00/08-11-069-22W5, 00/10-11-069-22W5, 03/12-11-069-22W5, and 00/06-12-069-22W5.

These four wells produced an average of 652 m^3/day of formation water per well. The well that produced the greatest volume of formation water from the Leduc Formation is 08-11-069-22 W5M, which is within the permit area. This well produced a total of 4,213,257 m^3 of formation water from October 1995 to December 2010, an average of 783 m^3/day. Formation water represents 97% of the total liquid produced from the 08-11-069-22W5M well.

14.3.8 Hydraulic Head

The hydraulic-head elevations calculated by Melange from the DST data are based on the following equation:

$(KB - GD) + (P/9.81)$

Where:

KB	=	kelly bushing elevation in metres amsl
GD	=	gauge depth in metres below KB
P	=	reservoir pressure in kPa
9.81	=	gravitational acceleration in metres per second squared (m/second^2)

Figure 14.13 and Figure 14.14 show the freshwater hydraulic heads that have been calculated for the 26 DSTs that were assessed by Melange for the Leduc Formation at the Boardwalk Property. The graph and table show that freshwater hydraulic head in the Leduc Formation has declined from approximately 900 m AMSL in the mid-1950s to approximately 300 m AMSL in the mid-1990s.

The available head (available drawdown) is the difference in elevation between the hydraulic-head and the elevation of the top of the Leduc Formation at that location. The freshwater available head at the 26 DST locations ranges from 2,185 to 2,427 m, with an average of 2,286 m, and is summarized in Figure 14.14.

To convert the freshwater head into a hypothetical formation water, or brine, head (that has a specified density) we use the following adjusted formula of *pressure head* = $\rho g h$ (Domenico and Schwartz, 1990), where

$h_{formation\ water} = h_{fresh\ water} * (\rho_{fresh\ water}/\rho_{formation\ water})$

Assuming The Leduc Formation brine has a density of 1.138 g/cm^3, the freshwater hydraulic head of 2,286 is divided by the density to yield a formation water hydraulic head of 2,009 m.

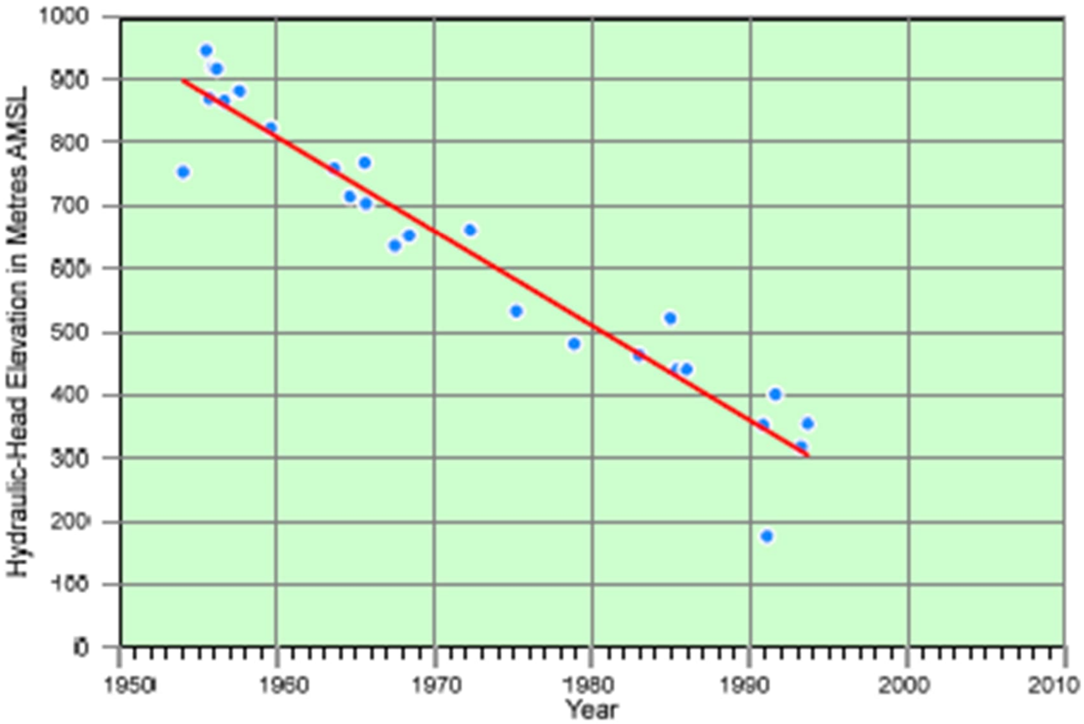


Figure 14.13: Leduc Formation freshwater hydraulic head at the Boardwalk Property

Location	DST Test Date	KB (m) (m AMSL)	Leduc Top (m AMSL)	Available Drawdown (m)*
100/03-03-070-23W5	16-Jan-54	725.1	-2,013.4	2,313.4
100/01-08-068-23W5	02-Jul-55	791.7	-2,096.0	2,396.0
100/11-30-068-21W5	15-Sep-55	641.6	-1,911.2	2,211.2
100/01-31-068-21W5	30-Nov-55	652.6	-1,933.4	2,233.4
100/13-32-068-21W5	01-Mar-56	653.2	-1,938.9	2,238.9
100/15-06-069-21W5	25-Aug-56	650.1	-1,905.1	2,205.1
100/13-24-068-22W5	09-Aug-57	655.6	-1,885.1	2,185.1
100/01-11-072-24W5	06-Aug-59	768.1	-2,105.2	2,405.2
100/02-25-071-24W5	17-Aug-63	739.1	-1,958.2	2,258.2
100/05-17-070-23W5	18-Aug-64	709.9	-1,952.8	2,252.8
100/13-04-070-23W5	22-Jul-65	716.9	-1,945.7	2,245.7
100/09-08-069-22W5	22-Aug-65	684.9	-1,929.3	2,229.3
100/09-18-070-23W5	23-Jun-67	705.0	-1,955.2	2,255.2
100/07-04-068-22W5	16-May-68	679.1	-2,061.9	2,361.9
100/10-20-067-22W5	09-Apr-72	700.7	-2,054.3	2,354.3
100/07-33-071-23W5	08-Mar-75	810.5	-1,982.8	2,282.8
100/01-08-069-22W5	08-Nov-78	684.4	-1,936.9	2,236.9
100/08-12-067-23W5	19-Dec-82	725.1	-2,048.1	2,348.1
100/06-30-067-23W5	11-Dec-84	775.6	-2,127.1	2,427.1
100/06-02-072-24W5	24-Apr-85	758.0	-2,101.2	2,401.2
100/11-03-068-22W5	17-Dec-85	676.5	-2,091.6	2,391.6
100/15-24-069-23W5	10-Nov-90	745.4	-1,963.5	2,263.5
102/04-07-069-21W5	02-Feb-91	650.0	-1,907.4	2,207.4
100/08-36-070-25W5	14-Aug-91	699.5	-2,038.1	2,338.1
100/04-32-071-23W5	31-Mar-93	779.2	-1,898.7	2,198.7
100/06-23-068-22W5	01-Sep-93	659.8	-1,905.1	2,205.1
			Average:	**2,286.4**

* Based on a representative hydraulic head elevation of 300 m AMSL

Figure 14.14: Leduc Formation freshwater hydraulic head at the Boardwalk Property

14.3.9 Summary of Representative Hydraulic Properties

Based on a review of the referenced literature and data, representative hydraulic parameter values for the Leduc Formation have been determined and are summarized in Figure 14.15.

It is the opinion of the QP that the Leduc Formation aquifer within the Sturgeon Lake Reef Complex underlying LithiumBank's Boardwalk Property has reservoir properties that have displayed a long history of consistent fluid yields. The authors have shown that key hydrogeological variables within the Leduc Formation demonstrate and meet the criteria for reasonable prospects for a potential economic extraction.

14.3.10 Potential For Brine Production

The theoretical long-term pumping rate from a single well can be estimated using the Farvolden equation (1959) which assumes an infinite aquifer extent and is based on available head and effective transmissivity.

Parameter	Leduc Formation
Effective Porosity (%)	5.3
Permeability (mD)	19
Hydraulic Conductivity (m/s)	4.2E-07
Mean Formation Thickness (m)	206
Transmissivity from DSTs (m^2/day)	7.4
Specific Storage (m^{-1})	4.E-06
Storativity (-)	8.E-04
Available Freshwater Hydraulic Head (m)	2,286
Available Formation Water Hydraulic Head (m)	2,009

Figure 14.15: Summary of representative hydraulic parameters for the Leduc Formation

A hypothetical well with the average available head of 2,009 m of formation water completed in an aquifer with a transmissivity of 7.4 m^2/day would have a 20-year estimated yield of approximately 7,000 m^3/day using the Farvolden method and the representative hydraulic properties from the Leduc Formation (Figure 14.15). This is a large yield from a single source well and would likely be limited by the effects of well efficiency (skin), pump capacity, areal extent of the aquifer and aquifer heterogeneity.

This prediction of long-term yield is subject to uncertainty due to the uncertainty associated with the hydraulic parameters listed in Figure 14.15. Despite the prediction uncertainty, the calculated long-term yield suggests there is a potential to extract substantial quantities of brine from the Leduc Formation.

14.4 Geometry and Volume of the Leduc Formation Aquifer Domain

14.4.1 Three-Dimensional Geological Model

The digital elevation model for the Boardwalk Property surface area was derived from publicly available Shuttle Radar Topography Mission (SRTM) 1-Arc Second data. The 1-Arc Second dataset has a grid size of 30 m. The surface data was captured between February 11 and 22, 2000 by the Space Shuttle Endeavour.

The top of the Leduc Formation was defined within 814 wells in the Boardwalk Property area (Figure 14.16). This included 499 Leduc wells identified using Accumap, and 315 Leduc wells identified using GeoVista (Figure 14.16a). In most cases, both data sources picked the top of the Leduc Formation within the same wells. In some cases, the reported spatial coordinates for the well differed by a few metres.

In addition, the top of the Leduc formation may have differed by a few metres. For example, well 100/05-05-071-24W5/0 defined the top of the Leduc Formation at -2,161.5 m and -2,157.5 m below sea level in GeoVista and Accumap, respectively. In most cases where there were discrepancies in the top Leduc horizon picks, the authors averaged the top value to minimize the error.

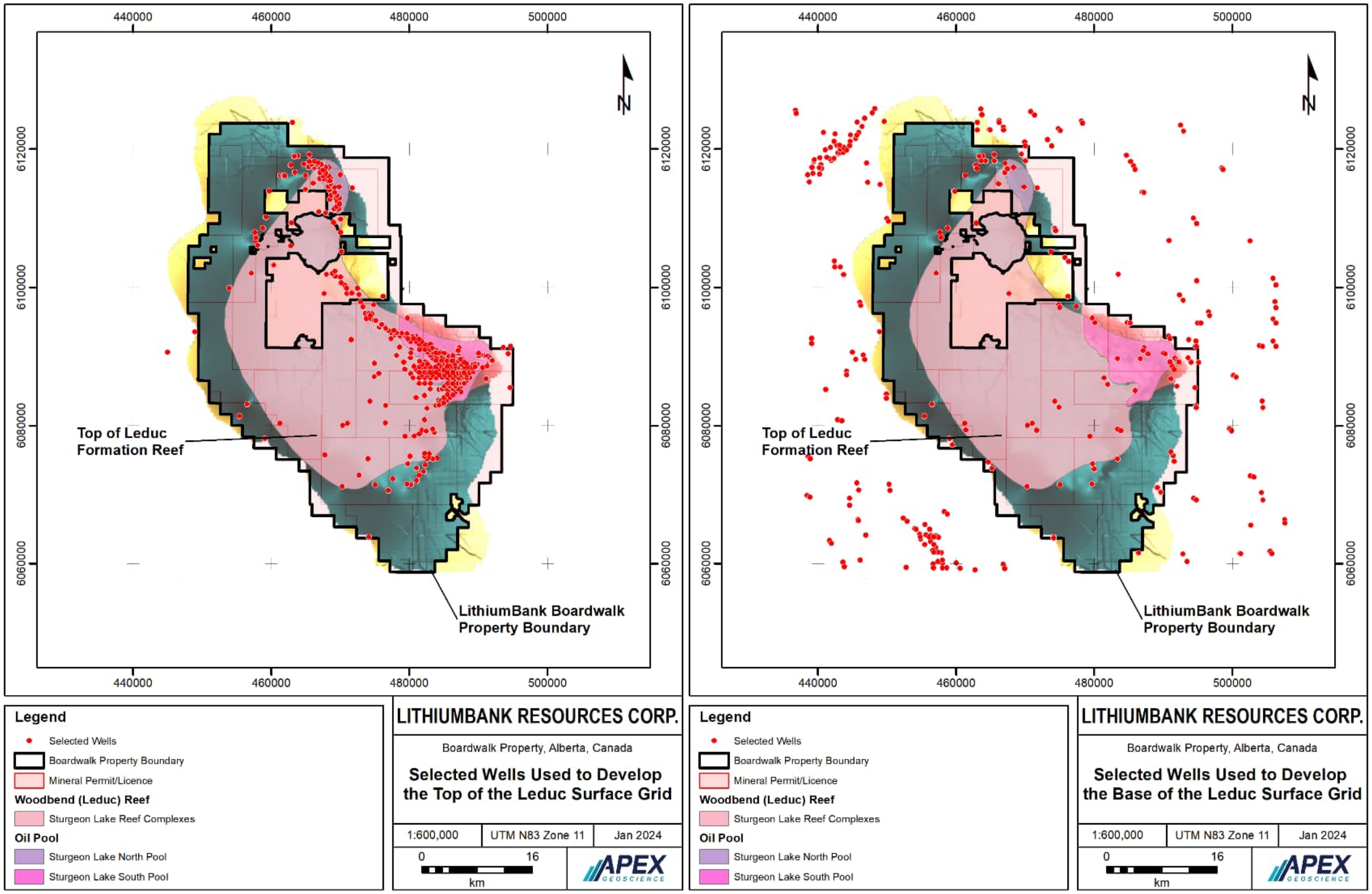


Figure 14.16: Summary of well used to pick the formation tops of the Leduc Formation and Beaverhill Lake Group (equivalent to the base of the Leduc Formation)

The top of the Beaverhill Lake Group, which directly underlies the Leduc Formation, was used to represent the base of the Leduc Formation. A total of 462 wells were used as control points to construct the base of Leduc Formation grid (Figure 14.16b). The data were acquired from Accumap, which identified 202 Beaverhill Lake Group tops, Geovista, which yielded 156 Beaverhill Lake Group tops, and an internal formation pick database used by HCL that identified 104 Beaverhill Lake Group tops. Again, there is a lot of overlap between the three data sources, with minor differences in the spatial well coordinates.

A 3-D image of the Leduc Formation reef is presented in Figure 14.1. The reef complex is defined by oil and gas wells that define the true vertical depth of the Leduc Formation at depths of between -2,337.6 m and -3,050.6 m (average -2,619.9 m) below the Earth's surface. The Leduc reef has a thickness of approximately 230 to 380 m with average and maximum thicknesses of 206 m and 408 m, respectively, at the Boardwalk Property.

It is the senior author's opinion that the results of the formation top and base picks are reasonable and do not over- or under-estimate the regional Leduc Formation model in the Boardwalk Property area. The grid files, and subsequent Leduc aquifer volume, are therefore suitable for resource estimations as reported in this Technical Report.

The outline of the Sturgeon Lake Reef Complex is constrained with well data. The outline of the Sturgeon Lake South Oilfield (i.e., indicated resource area) is identifiable within the density of oil and gas wells and has been detailed in oil and gas reservoir production characterizations (e.g., Anderson et al., 1989; Stoakes and Campbell, 1996).

14.4.2 Leduc Formation Aquifer Domain Wireframe and Volume Calculations

Two separate 3-D wireframes of the Leduc Formation aquifer domain were created using the grid surfaces of the top and base of the Leduc Formation within the 3-D geological model along with the spatial dimensions of the Sturgeon Lake South Oilfield (indicated resource area) and remaining Leduc area within the Sturgeon Lake Reef Complex (inferred resource area). The 2-D strings were connected to create solid 3-D wireframes of the Leduc Formation aquifer within each resource area (Figure 14.17).

The wireframe of Leduc Formation aquifer domain was extended beyond the property boundary to ensure continuity and was then clipped to the extents of the permits for the resource estimation. This step ensures that we restrict the resulting wireframe volumes within each licences area. Only those parts of the Sturgeon Lake Reef Complex that occur within the LithiumBank property were used in the resource estimate process. Indigenous Lands and Provincial Parks in the north-central part of the Property were removed from the resource modeling area and were not included in the resource estimation.

The closed 3-D solid polygon wireframes of the Leduc Formation aquifer domain were used to calculate the volume of rock, or the aquifer volume within the indicated and inferred resource areas. The Leduc Formation domain aquifer volume underlying the Boardwalk Property within the indicated and inferred resource areas is 19.94 km^3 and 305.00 km^3, respectively.

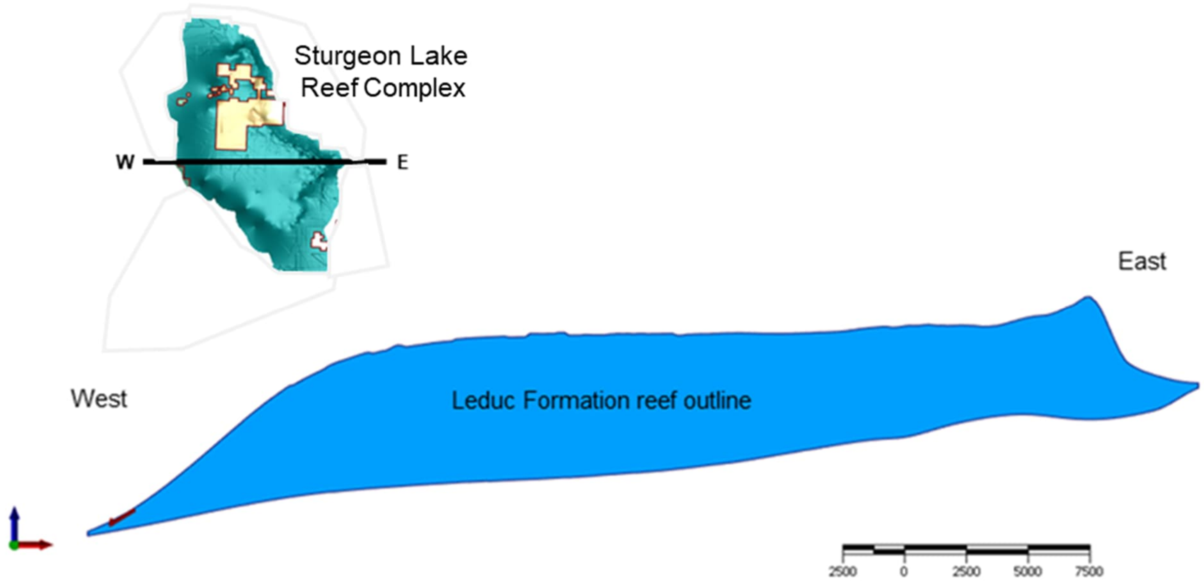


Figure 14.17: West-east cross-section of the Leduc Formation reef at the Boardwalk Property

14.5 Leduc Formation Aquifer Domain Brine Volume

The brine volume is calculated for the Leduc Formation aquifer domain within the resource areas, by multiplying the aquifer volume (in km^3) times the average porosity times the percentage of brine assumed within the pore space. Using an average porosity value of 5.3% (see Section 14.3.1) and the average modal abundance of brine in the Leduc formation pore space percentage of 98% (see Section 14.3.7), the Leduc Formation aquifer domain brine volume in the indicated and inferred resource areas is 1.036 km^3 and 15.84 km^3.

14.6 Lithium-Brine Concentration

During 2021, LithiumBank formed a brine access agreement with a Petro-company operating in the Sturgeon Lake Oilfield. This entitled LithiumBank to conduct a brine sampling program that involved reopening four suspended oil and gas wells in the Sturgeon Lake South Oilfield. The program collected a total of 44 one-litre brine assay samples, which included 28 ‘original’ or ‘duplicate’ samples with a variety of QA-QC samples. The 28 samples, which were analyzed at AGAT and BV, had a range of lithium concentrations from 54.9 mg/L Li to 77.6 mg/L Li (average of 69.9 mg/L Li).

In addition to the brine samples collected by the Company’s during their 2021 sampling program at the Sturgeon Lake South Oilfield, LithiumBank is reliant on historical government- and industry-documented brine assays to determine an average Li-brine concentration for use in the resource estimation calculation related to the overall Sturgeon Lake Reef Complex. A significant portion of the historical samples were analyzed at Maxxam Analytical Laboratories (now BV).

A summary of the LithiumBank-collected and historical data is presented in Figure 11.5 The QP has evaluated the datasets and rationalizes that independent average Li-brine concentrations be used for the indicated and inferred resource areas as discussed in the text that follows.

14.6.1 Indicated Resource Average Lithium Concentration

LithiumBank's 2021 brine sampling program validated the historical brine content of the Leduc Formation underlying the Boardwalk Property; significantly, the program validated brine obtained from the Sturgeon Lake South Oilfield.

LithiumBank's primary laboratory is AGAT Laboratory (see check-lab discussion in Section 11.3.4). A summary of the AGAT-specific geochemical results of LithiumBank's 2021 brine sampling and analytical program is presented in Figure 9.4 (and Figure 14.10c). The tables show a total of 25 original LithiumBank Leduc Formation brine samples from the Sturgeon Lake South Oilfield were assayed at AGAT and yield average values of 71.6 mg/L Li, 129.9 mg/L B, 914.8 mg/L Sr, 24,724 mg/L Ca, 2,614 mg/L Mg, 55,332 mg/L Na, and 4,271 mg/L K. The RSD% of, for example, lithium is 4%, suggests strong analytical reproducibility.

Because LithiumBank's sample program analyzed representative Leduc Formation brine from 4 wells located in the Sturgeon Lake South Oilfield, and LithiumBank has demonstrated justification for using AGAT as the Company's primary lab – it is the QPs opinion that the average Li-brine value of 71.6 mg/L Li is representative of the lithium concentration of the Leduc Formation brine underlying the Sturgeon Lake South Oilfield portion of the Sturgeon Lake Reef Complex (i.e., the indicated resource area).

14.6.2 Inferred Resource Average Lithium Concentration

LithiumBank has yet to collect and validate Leduc Formation brine from those areas outside of the Sturgeon Lake South Oilfield, including for example, the Sturgeon Lake North Oilfield. As such, the confidence of the lithium concentration in the Leduc Formation brine in the inferred resource area is lower than in the indicated resource area, where the Li-brine was validated in 2021 by LithiumBank.

Hence, QP recommends that the average lithium concentration of the inferred mineral resource area, which encompasses the reef complex outside of the Sturgeon Lake South Oilfield (indicated resource area) should use a combination of historical and LithiumBank-2021-derived lithium analytical results to define the overall Sturgeon Lake Reef Complex Li-brine concentration.

A) Exploration lithium assays. Abbreviations: LEXG - Lithium Exploration Group; MGX - MGX Minerals Inc.

	LEXG Li (mg/L) Sturgeon Lake	LEXG Li (mg/L) North Sturgeon Lake	LEXG Li (mg/L) South Sturgeon Lake	MGX Li (mg/L) Sturgeon Lake	MGX Li (mg/L) North Sturgeon Lake	MGX Li (mg/L) South Sturgeon Lake
Count	47	7	40.0	12	4	8
Minimum	55.4	55.4	58.1	35.6	60.5	35.6
Maximum	83.7	74.0	83.7	64.7	61.9	64.7
Mean	67.5	66.1	67.8	59.3	61.1	58.4
Std. Dev.	5.5	8.2	5.0	7.6	0.6	9.4
RSD%	8.1	12.5	7.3	12.8	1.0	16.1

B) Government lithium assays

	Eccles (2011) and Huff (2019) Li (mg/L) Sturgeon Lake	Huff (2019) Li (mg/L) North Sturgeon Lake	Eccles (2011) Li (mg/L) South Sturgeon Lake
Count	4	2	2
Minimum	75.3	75.3	84.0
Maximum	140.0	82.6	140.0
Mean	95.5	79.0	112.0
Std. Dev.	29.9	5.2	39.6
RSD%	31.3	6.5	35.4

C) LithiumBank 2021 sampling program lithium assays

	Li (mg/L) South Sturgeon Lake (AGAT and BV)	Li (mg/L) South Sturgeon Lake (AGAT only)
Count	28	25.0
Minimum	54.9	65.7
Maximum	77.6	77.6
Mean	69.9	71.6
Std. Dev.	5.6	2.9
RSD%	8.1	4.0

D) All lithium assays

	All data Li (mg/L) Sturgeon Lake	All data Li (mg/L) North Sturgeon Lake	All data Li (mg/L) South Sturgeon Lake
Count	91	13	78
Minimum	35.6	55.4	35.6
Maximum	140.0	82.6	140.0
Mean	68.4	66.5	68.7
Std. Dev.	10.3	8.5	10.6
RSD%	15.1	12.7	15.5

E) All lithium assays (minus outlier values of 35.6 and 140.0 mg/l Li).

	All data Li (mg/L) Sturgeon Lake
Count	89
Minimum	54.9
Maximum	84.0
Mean	68.0
Std. Dev.	6.2
RSD%	9.1

Figure 14.18: Summary of industry and government lithium analyses on Leduc Formation aquifer brine at the Sturgeon Lake Oilfield

A total of 89 brine analysis, from LithiumBank's 2021 brine sampling program and from historical industry and government of Alberta surveys, has been considered in assessing the lithium concentration value used in the inferred resource area estimation area. All 89 analyses are from brine samples collected within the Leduc Formation aquifer underlying LithiumBank's Property from wells that are situated within the Property's boundary.

The quality of these analytical data is assessed using average percent relative standard deviation (also known as the % coefficient of variation), or average RSD%, as an estimate of precision or reproducibility of the analytical results. In the following discussion, average RSD% values below 10% are considered to indicate excellent data quality; between 10% and 30%, good quality, between 30% and 50%, moderate quality and over 50%, poor quality. The higher an average RSD% value is, the less likely it is to be able distinguish a real pattern from noise.

A histogram of the lithium concentration distribution is presented in Figure 14.19, and shows 1) homogeneous Li-brine concentration with most of the samples containing lithium in the histogram bins between 56-60 mg/L Li and 76-80 mg/L Li, and 2) two outlier analysis of 35.6 mg/L Li and 140 mg/L Li.

When all data (n=91) are averaged, the concentration is 68.4 mg/L Li. These data yield an RSD% of 15.1% indicative of good data quality (Figure 14.19). To improve the reproducibility of the analytical results, the two outlier values of 35.6 mg/L Li and 140 mg/L Li were removed from the assay data; the resulting concentration of 89 analyses is 68.0 mg/L Li (Figure 14.9d). The RSD% subsequently reduced to 9.1%, which is considered a very high-level of analytical precision.

Consequently, the average Leduc Formation aquifer brine lithium concentration of 68.0% mg/L Li was used for the inferred resource estimation calculation.

14.6.3 Qualified Person Comment on Average Lithium Concentration Used in the Resource Estimations

During 2022, LithiumBank conducted a round-robin laboratory test audit by sending a laboratory-prepared hypersaline lithium sample standard to four commercial, accredited laboratories and two independent labs (see Section 11.3.4).

The results have shown that one of the labs reported lower values of lithium in comparison to the other five labs. The lab in question completed brine geochemical analyses that form part of the historical work presented in this technical report, and these data were used by the QP to determine the average Li-brine value used in the inferred mineral resource area calculations. Hence, and in the QPs opinion having reviewed the lab audit, the average Li-brine value used in the inferred mineral resource area work is considered conservative in nature. It is possible that with future LithiumBank sampling and analytical work the inferred mineral resource estimate presented in this technical report is subject to change.

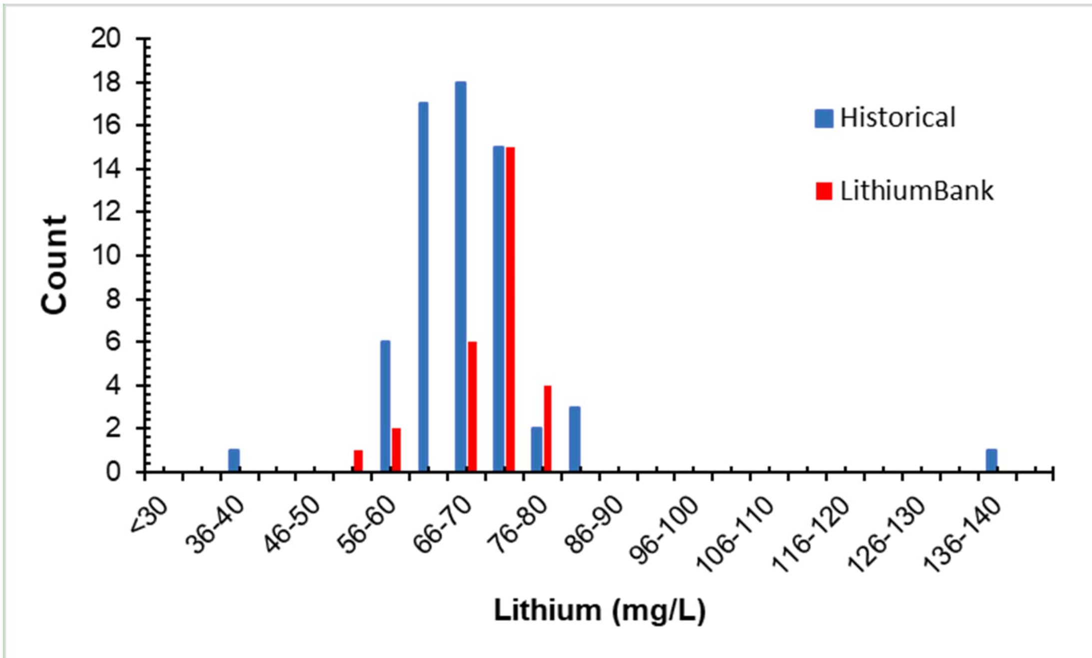


Figure 14.19: Histogram of exploration and government brine lithium concentrations

14.7 Top Cuts and Capping

No top cuts or capping upper limits have been applied to the lithium assay values or are deemed to be necessary. Confined Li-brine deposits typically do not exhibit the same extreme values as precious metal deposits. It is the opinion of the QP that this statement is applicable to the Leduc Formation aquifer Li-brine data and capping is not required.

However, and to improve the reproducibility of the analytical results, two outlier values of 35.6 mg/L Li and 140 mg/L Li were removed from the assay data (see Section 14.6). The histogram of assay results presented in Figure 14.19 shows that these two samples are not part of the same population. It is the opinion of the QP that removing these two assays is acceptable and that the erroneous data are not representative of the Leduc Formation aquifer Li-brine within the Sturgeon Lake Oilfield reservoir.

14.8 Market Conditions and Pricing

There is high demand for critical metals that will supply the growing need for Electric Vehicles (EVs) and batteries. Other demand opportunities include consumer electronics, energy storage, and other industrial applications. As the lightest metal on the periodic table, and reactive in that it is the one most eager to shed its electrons, lithium is the ideal element to make powerful, portable batteries. This demand has resulted in a global surge in lithium exploration, including confined aquifer Li-brine deposit types. Current projections for the annual lithium demand are led by EV consumption and have been projected to reach roughly 1.5 million metric tons of lithium carbonate equivalent by 2025 and approximately 2.5 to 3 million tons by 2030 (Norris, 2022; Statista, 2022).

Lithium chemicals are typically sold in private supply contracts between producer and industrial user. These contracts are typically for a specific chemical composition and set for a period that may vary between weeks to several years (generally between three months to one year). The most traded lithium chemical products include spodumene concentrate (produced in hard rock lithium deposits), lithium carbonate and lithium hydroxide monohydrate; the latter two represent intended end products associated with Li-brine projects. Specific discussion related to pricing within the scope of this PEA is presented in Section 19.

14.9 Reasonable Prospects

Critical matters likely to influence the prospect of economic extraction of Li-brine from the Devonian Leduc Formation aquifer include aquifer dimensions, brine composition, fluid flow, brine access and mining methods, recovery extraction technology and environmental factors. These issues are discussed below and summarized at the end of the discussion by a concluding opinion of the senior author and QP.

Aquifer dimensions: The top and base of the Leduc Formation aquifer was defined using stratigraphic horizon picks from 814 wells and 462 wells within the Boardwalk Property. The outline of the indicated resource area is based on oil and gas wells and reservoir production studies of the Sturgeon Lake South Oilfield. It is the senior author's opinion that the 3D geological model is reasonable and does not over- or under-estimate the regional Leduc Formation in the Boardwalk Property area. The subsequent Leduc aquifer volumes are therefore suitable for resource estimations as reported in this Technical Report.

Brine lithium access and composition: Brine analytical data includes both historical and LithiumBank-derived data. The 2021 brine sampling program completed by LithiumBank validated the historical government- and industry-documented Li-brine assays. Average Li-brine concentrations used in the resource estimation process were 71.6 mg/L Li (indicated resource area) and 68.0 mg/L Li (inferred resource area). It is the opinion of the QP that the lithium geochemical data yield reasonable and representative lithium values of the Leduc Formation brine underlying the Boardwalk Property and within the two resource areas.

Hydrogeological characterization and fluid flow: A hydrogeological assessment of the Sturgeon Lake Reef Complex was investigated using a variety of public and proprietary sources. Based on analysis of effective porosity from 99 separate core plug measurements and total porosity derived from geophysical logs, the representative average effective porosity of the Leduc Formation underlying the Boardwalk Property is 5.3%. Based on 2008-2011 production data (n=46 wells), the average modal abundance of brine in the Leduc formation pore space is 98%. Based on drill stem tests, a permeability of 19 mD is considered most representative of the Leduc Formation. The best estimate from the existing data of calculated transmissivity is 7.4 m^2/day with a storativity of 8.0×10^{-4}.

Recovery extraction technology: During 2022, LithiumBank commissioned mineral processing test work at Go2Lithium's lab facility, which entails the bench scale of tests on the thermodynamic and kinetic properties of the DLE sorbent for loading and elution. The DLE sorbent utilized in the test program demonstrates capability to selectively extract lithium from LithiumBank's feed brine within reasonable efficiency to produce a lithium concentrate. The QP has reviewed the Go2Lithium testwork report results and is confident that the quantity and quality of the test work for this stage of the project evaluation is sufficient for this Technical Report.

Environmental factors or assumptions: With respect to early-stage exploration for lithium, and to the best of the author's knowledge, there are no other significant factors and risks that may affect access, title or right or ability to perform minerals exploration work at the Boardwalk Property. It is not expected that the brine access agreement would put LithiumBank in a position where the Company is environmentally responsible for any liabilities or damage inflicted because of, or associated with, the production of petroleum products or the oil and gas lease(s).

To conclude, this Li-brine Technical Report has been prepared by a multi-disciplinary team that include geologists, hydrogeologists, and chemical engineers with relevant experience in the geology of the Western Canada Sedimentary Basin, brine geology/hydrogeology, and Li-brine processing.

There is collective agreement that the LithiumBank Li-brine project at the Boardwalk Property has reasonable prospects for eventual economic extraction of lithium from brine, and the author, Mr. Eccles P. Geol., takes responsibility for this statement.

14.10 Cutoff

In establishing a cutoff grade, the QP must realistically reflect on the location, deposit scale, continuity of mineralization, assumed mining method, metallurgical processes, costs, and reasonable long-term metal prices appropriate for any deposit. The cutoff value must be relevant to the grade distribution modelled for the mineral resource, and represent the lowest grade, or quality, of mineralized material that qualifies as being economically mineable.

The lithium content of the Leduc Formation brine at the Boardwalk Property forms a tight cluster of homogeneous lithium values of between 56-60 mg/L Li and 75-80 mg/L Li (average of 68.0 mg/L Li; n=89 analyses).

A growing number of laboratories (commercial, academia, independent) are attempting to develop modern technology that will beneficiate and recover lithium from unconfined aquifer deposits in real time (as solar evaporation is typically not a beneficiation option). The developers are aware that the technology must incorporate lower source concentrations of lithium and are therefore testing at low lithium concentrations. Accordingly, there are several laboratories that are experimenting with rapid lithium extraction techniques and/or conduct test work on low lithium source brine, including starting source levels of approximately 50 mg/L lithium (e.g., approximately70 mg/L Li, McEachern, 2017a,b; ≤60 mg/L Li, Xu et al., 2017; 50 mg/L Li, Snydacker, 2018).

It is the opinion of the author that a lower cutoff of 50 mg/L lithium is acceptable as this cutoff, or lower values, have been used to define other confined aquifer brine deposit (e.g., Dworzanowski et al., 2019), which traditionally have lower concentrations of lithium in comparison to salar and hard rock lithium deposits.

Lastly, the author recommends that the cutoff value continues to be evaluated as LithiumBank advances their Li-brine Project and the lithium recovery from brine process. It is possible that this lower cutoff will be adjusted in future Technical Reports with higher levels of resource/reserve classification.

14.11 Mineral Resource Estimate

14.11.1 Resource Classification

The Boardwalk Leduc Formation Li-brine resource estimations are classified as 'Indicated' and 'Inferred' Mineral Resources in accordance with CIM definition standards and best practice guidelines for mineral resources and reserves (2014, 2019), and the disclosure rule NI 43-101. By definition,

"An Inferred Mineral Resource is that part of a Mineral Resource for which quantity and grade or quality are estimated on the basis of limited geological evidence and sampling. Geological evidence is sufficient to imply but not verify geological and grade or quality continuity. An Inferred Mineral Resource has a lower level of confidence than that applying to an Indicated Mineral Resource and must not be converted to a Mineral Reserve. It is reasonably expected that the majority of Inferred Mineral Resources could be upgraded to Indicated Mineral Resources with continued exploration."

"An Indicated Mineral Resource is that part of a Mineral Resource for which quantity, grade or quality, densities, shape, and physical characteristics are estimated with sufficient confidence to allow the application of Modifying Factors in sufficient detail to support mine planning and evaluation of the economic viability of the deposit. Geological evidence is derived from adequately detailed and reliable exploration, sampling and testing and is sufficient to assume geological and grade or quality continuity between points of observation."

The indicated mineral resource area, defined as the Sturgeon Lake South Oilfield, has been elevated to an indicated resource classification in this technical report because of:

1. The overall number of historical and LithiumBank-collected brine samples analyzed for lithium in the Sturgeon Lake South Oilfield (78 of 91 samples in comparison to the Sturgeon Lake North Oilfield, or 85%).
2. LithiumBank has independently validated both the historical Li-brine values, and Li-brine content of the Leduc Formation aquifer brine at the Sturgeon Lake South Oilfield as part of the Company's 2021 sampling program.
3. LithiumBank acquired, reprocessed, and reinterpreted seven existing 2-D seismic lines totaling 67 line-kilometres that effectively covers the Sturgeon Lake South Oilfield, the

results of which have increased the understanding of the dimensions of the Leduc Formation reef buildups.

4. LithiumBank conducted preliminary mineral processing test work that utilized representative Leduc Formation aquifer brine from the Sturgeon Lake South Oilfield.

Hence, the information improves/validates the overall confidence level in the geology of the main Leduc reef trend underlying the Property and in the concentration of lithium in the Leduc Formation brine within the area of the Sturgeon Lake South Oilfield.

With respect to the inferred mineral resource area (the reef complex area outside of the Sturgeon Lake South Oilfield), it is the opinion of the senior author and QP that the inferred resource area requires further exploration work to elevate the resource to a higher classification level. This work includes additional brine sampling to validate the historical geochemical brine results.

The indicated and inferred resources both require ongoing brine processing test work toward the development of a modern direct lithium extraction technology.

14.11.2 Mineral Resource Reporting

The Effective Date of the Boardwalk Leduc Formation Li-brine resource estimations is 22 February 2024.

The resource estimations are based on the classical lithium-brine equation, *Lithium Resource* = $A \times T \times P \times C$, where A = area of aquifer; T = thickness of aquifer; P = porosity of aquifer; and C = concentration of lithium in brine (e.g., Collins, 1976; Gruber et al., 2011). Where possible, due diligent effort was considered to obtain the best-use values for these parameters.

The indicated and inferred Boardwalk Leduc Formation lithium-brine resource estimations are presented as a total (or global value), was estimated using the following relation in consideration of the Leduc Formation aquifer brine:

Lithium Resource = Total Brine Aquifer Volume X Average Porosity X Percentage of Brine in the Pore Space X Average Concentration of Lithium in the Brine.

Closed 3-D solid polygon wireframes of the Leduc Formation aquifer domain within the indicated and inferred resource areas were used to calculate a volume of rock, or aquifer volume. The polygons were clipped to the outline of the Sturgeon Lake Reef Complex, which is located entirely within the boundary of the Boardwalk Property. The aquifer volume of the indicated and inferred resource areas is 19.94 km^3 and 305.00 km^3, respectively.

The Leduc Formation aquifer domain brine volume was calculated from the aquifer volume using an average Leduc Formation porosity value of 5.3% and the average modal abundance of brine in the Leduc Formation pore space percentage of 98%. The brine volume of the indicated and inferred resource areas is 1.04 km^3 and 15.84 km^3.

The average Leduc Formation aquifer brine lithium concentrations of 71.6 mg/L Li (indicated resource area) and 68.0 mg/L Li (inferred resource area) were selected for the resource estimation calculations.

The Li-brine resource was estimated using a cut-off grade of 50 mg/L lithium. With respect to units of measurement, 1 mg/L = 1g/m^3. If concentration is in mg/L and volume in m^3, then the calculated resource has units of grams. (1 g/m^3 x 1 m^3 = 1 gram or 0.001 kg).

The updated Boardwalk Leduc Formation Li-brine resource estimations predict:

- A globally (total) indicated Li-brine resource estimation of 74,000 tonnes of elemental Li. Using the industry standard conversion factor of 5.323 to convert elemental Li to Li_2CO_3, or Lithium Carbonate Equivalent (LCE), the indicated Li-brine resource is estimated to contain 395,000 tonnes LCE (Table 14-1).
- A globally (total) inferred Li-brine resource estimation of 1,077,000 tonnes of elemental Li, which is equivalent to 5,734,000 tonnes LCE (Table 14-2).

Mineral resources are not mineral reserves and do not have demonstrated economic viability. There is no guarantee that all or any part of the mineral resource will be converted into a mineral reserve. The estimate of mineral resources may be materially affected by geology, environment, permitting, legal, title, taxation, socio-political, marketing, or other relevant issues.

Table 14-1: Updated Boardwalk indicated Li—brine resource estimation presented as a global (total) resource that is contained within the Leduc Formation of the Sturgeon Lake South Oilfield.

	Reporting parameter	Leduc Formation Reef Domain
Indicated Resource Estimate	Aquifer volume (km^3)	19.942
	Brine volume (km^3)	1.036
	Average lithium concentration (mg/L)	71.6
	Average porosity (%)	5.3
	Average brine in pore space (%)	98.0
	Total elemental Li resource (tonnes)	74,000
	Total LCE (tonnes)	395,000

Note 1: Mineral resources are not mineral reserves and do not have demonstrated economic viability.
Note 2: The weights are reported in metric tonnes (1,000 kg or 2,204.6 lbs).
Note 3: Tonnage numbers are rounded to the nearest 1,000 unit.
Note 4: In a ‘confined’ aquifer (as reported herein), porosity is a proxy for specific yield.
Note 5: The resource estimation was completed and reported using a cutoff of 50 mg/L Li.
Note 6: To describe the resource in terms of the industry standard, a conversion factor of 5.323 is used to convert elemental Li to Li_2CO_3, or Lithium Carbonate Equivalent (LCE).

Table 14-2: Updated Boardwalk inferred Li—brine resource estimation presented as a global (total) resource that is contained within the Leduc Formation that encompasses the Sturgeon Lake Reef Complex outside of the Sturgeon Lake South Oilfield (or area of the indicated mineral resource).

	Reporting parameter	Leduc Formation Reef Domain
Inferred Resource Estimate	Aquifer volume (km^3)	304.999
	Brine volume (km^3)	15.842
	Average lithium concentration (mg/L)	68.0
	Average porosity (%)	5.3
	Average brine in pore space (%)	98.0
	Total elemental Li resource (tonnes)	1,077,000
	Total LCE (tonnes)	5,734,000

Note 1: Mineral resources are not mineral reserves and do not have demonstrated economic viability.
Note 2: The weights are reported in metric tonnes (1,000 kg or 2,204.6 lbs).
Note 3: Tonnage numbers are rounded to the nearest 1,000 unit.
Note 4: In a 'confined' aquifer (as reported herein), porosity is a proxy for specific yield.
Note 5: The resource estimation was completed and reported using a cutoff of 50 mg/L Li.
Note 6: To describe the resource in terms of the industry standard, a conversion factor of 5.323 is used to convert elemental Li to Li_2CO_3, or Lithium Carbonate Equivalent (LCE).

14.12 Reconciliation of Mineral Resources

With respect to reconciliation of mineral resources, and in comparison, to LithiumBank's previous technical report with an effective date of June 16, 2023, the updated Boardwalk

- Indicated Mineral Resource estimate is similar with a slight increase in LCE from 393,000 tonnes LCE to 395,000 tonnes LCE in the current technical report (a difference of +0.5%).
- Inferred Mineral Resource estimate is slightly lower in LCE from 5,808,000 tonnes LCE to 5,734,000 tonnes LCE in the current technical report (a difference of -1.3%).

Reconciliation of the updated mineral resources is entirely related to the recent change, and reduction, in the Boardwalk Property land position. The updated Li-brine resources do not represent a 100% or greater change in the total mineral resources at the Boardwalk Property. This is because the revised Boardwalk Property is more closely aligned with the outline of the Sturgeon Lake Reef Complex. No new scientific or technical information was provided by LithiumBank, or considered, during the preparation of the updated Boardwalk Indicated and Inferred Resource estimations presented in this, LithiumBank's current technical report.

15. Mineral Reserve Estimates

Section 0 of NI 43-101 have been omitted in this Technical Report: Not Applicable.

16. Mining Methods

16.1 General Description

The Mining Methods section of this report is intended to describe the method of lithium resource production. For the LithiumBank Boardwalk project, the lithium is sourced from brine water produced from the Leduc Formation as an in-situ resource. The production method is not with surface mining but using deep vertical or deviated wells into the Leduc Aquifer. The lithium rich brine will be produced from the wells, and then flow to the Central Processing Facility (CPF) via pipelines where lithium will be extracted.

The project is targeting a total lithium brine production rate of 250,000 m^3/d over a period of 20 years. This production rate is the basis for the numerical modeling and well network design.

16.2 Resource Recovery Method

The resource recovery method is based on production via subsurface wells. The lithium brine is produced to surface for processing to extract the lithium and returns the lithium depleted brine to the Leduc Aquifer via injection wells. The development plan assumes the installation of multi-well pads to minimize the surface footprint. Each pad will have deviated wells in order to achieve optimum bottomhole placement in the Leduc Formation.

An iterative approach was followed to determine an optimal well plan. The recommended well plan is referred to as the “well network” in this report. The distribution of the well network preferentially targets the thicker formation pay areas of the Leduc Aquifer and attempts to balance drawdown on each side of the injector wells.

The well network has 23 well pads with an average of four wells on each pad, for a total of 100 wells (50 production wells and 50 injection wells). The injection and production wells are spaced so that the production wells are capable of achieving the planned lithium brine production rates for 20 years without producing any of the lithium-depleted water that was re-injected into the Leduc Aquifer.

16.3 Well Network for Lithium Brine Production

The number, spacing, and location of wells in the well network has been determined based on a numerical modeling approach, with multiple iterations being run. Key assumptions in the numerical modeling include:

- Assuming the Leduc Aquifer is homogeneous and isotropic with the representative permeability values summarized in Table 16-1 below.
- The well network was designed to produce 250,000 m^3/day of lithium-rich brine for a 20-year period without exceeding the available drawdown at the production wells (average limit of 2,000 m formation water hydraulic head).
- The well network was designed to re-inject 250,000 m^3/day of lithium-depleted brine for a 20-year period without exceeding the maximum well head pressure (WHP) at the

injection wells (average limit of 10,553 kPa based on Directive 51). The production wells and injection wells needed to be sufficiently separated to prevent lithium-depleted water from reaching the production wells during a 20-year period of operation.

- A model of groundwater flow was built where the lateral boundaries to the Leduc reef are assumed to be no-flow and the top and bottom of the Leduc reef are also assumed to be no-flow.
- The transmissivity and storativity are spatially variable based on the mapped thickness and the representative hydraulic conductivity and specific storage respectively.

Table 16-1: Summary of representative hydraulic properties from Section 14.5 of Inferred Resource estimate

Hydraulic Parameter	Leduc Formation
Porosity (%)	5.3
Permeability (mD)	19
Hydraulic Conductivity (m/s)	4.2E-07
Average Thickness (m)	206
Transmissivity (m^2/d)	7.4
Specific Storage (m^{-1})	3E-05
Storativity (-)	7E-04
Available Freshwater Hydraulic Head (m)	2,286
Available Formation Water Hydraulic Head (m)	2,009

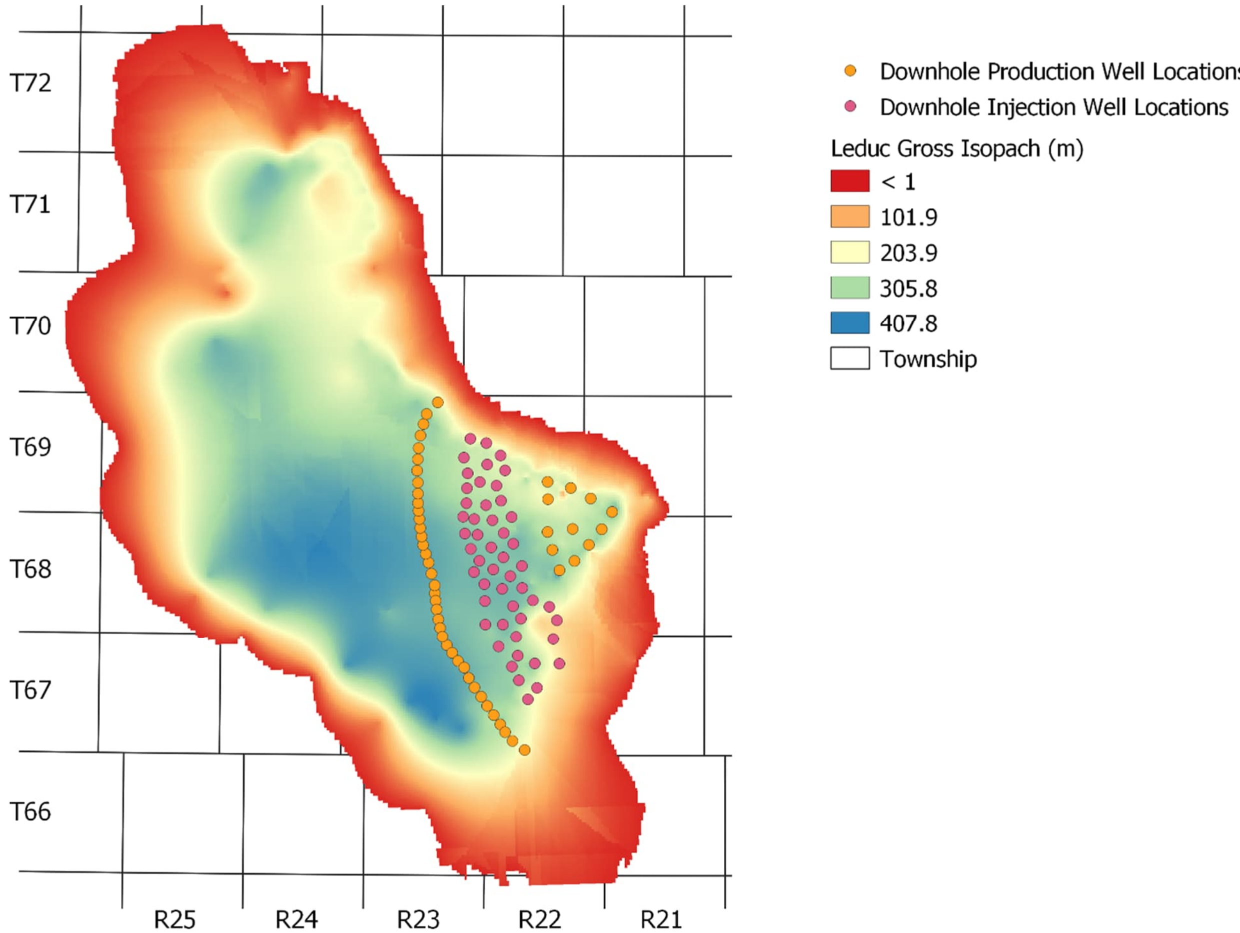


Figure 16.1: Thickness of the Leduc Formation as represented in the numerical model. The finite element mesh contains active elements (with assigned thickness). Map area is in West 5th Meridian, showing Township on Y axis and Range on X axis

Numerical modeling was completed at a total withdrawal rate of 250,000 m^3/day from a network of 50 production (source) wells; 38 in the west and 12 in the east. The wells were pumped at a constant rate of 5,000 m^3/day for the 20-year period. The model predictions are for hypothetical 7 ¾ inch diameter wells drilled at a 45 angle across the full thickness of the Leduc Formation. Because the wells are drilled at an angle, the producing interval of the well would be equal to 1.4x the thickness of the Leduc. It is assumed that once the well is drilled, developed, and acidized, the well would have a zero skin.

This well network analysis suggests the Leduc Formation can produce 250,000 m^3/day from 50 wells over a 20-year period (at an average pumping rate of 5,000 m^3/day). The pumping induced drawdown varies between the wells based on the Leduc thickness, the proximity of other wells in the well network, the proximity of the injection wells, and the proximity of the reef boundary. After 20 years, the average predicted drawdown in the wells is 1,060 m. None of the predicted drawdowns exceed the drawdown limit of 2,000 m (formation water hydraulic head). The present-day formation water hydraulic head in the Leduc is unknown but is estimated to be 70 masl. Based on the ground surface elevation at each well, the average depth to water in the well after 20 years of pumping is 1,707 m.

Lithium-depleted brine was simulated to be re-injected in 50 injection wells at a rate of 5,000 m^3/d at each well. The injection induced pressure increase varies between wells based on the same variables as the production wells. After 20 years, the average predicted pressure increase is 1,478 m. After adding line loss and considering the ground surface elevation, the average predicted wellhead pressure (WHP) is 10,307 kPa. The average predicted WHP is below the average maximum allowed WHP of 10,553 kPa.

The migration of lithium-depleted brine was predicted using particle tracking. The particle tracking results suggests lithium-depleted brine will not reach the production wells over the 20-year life of the project. Lithium depleted brine is predicted to migrate approximately two-thirds of the way to the production wells. This 50% margin of safety was deliberately incorporated into the well network design in recognition of the uncertainty in the effective porosity and the recognition that dispersion is not accounted for in particle tracking predictions. As designed the production and injection wells are sufficiently separated to prevent lithium-depleted brine from reaching the production wells during a 20-year period of operation.

16.4 Lithium Depleted Brine Injection

As part of the DLE processing, a lithium depleted brine stream of 5,307 m^3/day will be generated at the central processing facility (CPF). As such the total lithium-depleted brine will be re-injected into the Leduc Formation and this represents a 2% increase in the total injection rate relative to the feed due to water addition for washing in the process, from 250,000 m^3/day to 255,404 m^3/day.

The Leduc Formation is expected to accommodate the additional lithium depleted brine per the well network simulation described in Section 16.3. The additional volume is not expected to impact the feasibility of the brine production and re-injection scheme; however, it is expected that one extra injection well will be required to accommodate the lithium depleted brine stream. The placement of this well and costs would be considered in the next project stage and have not been included in this PEA.

16.5 Production Well Design

The well design for this project is based on consideration of many factors, including environmental and surface land use. To minimize disturbance and optimize capital and operating costs the plan is to install 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. This design concept applies to the production wells and injection wells on multi-well pads.

The bottomhole well placement is defined based on the well network numerical modeling and assumed spacing between the bottomhole locations. With these targets in mind, the well pads are planned with a series of deviated wells with varying degrees of inclination. This is a common drilling practice utilizing special tools for directional drilling. Below is a diagram showing a preliminary example well trajectory for a 45° well. This shows the bottom hole location at the Leduc top has an 1850 m departure from the wellhead location.

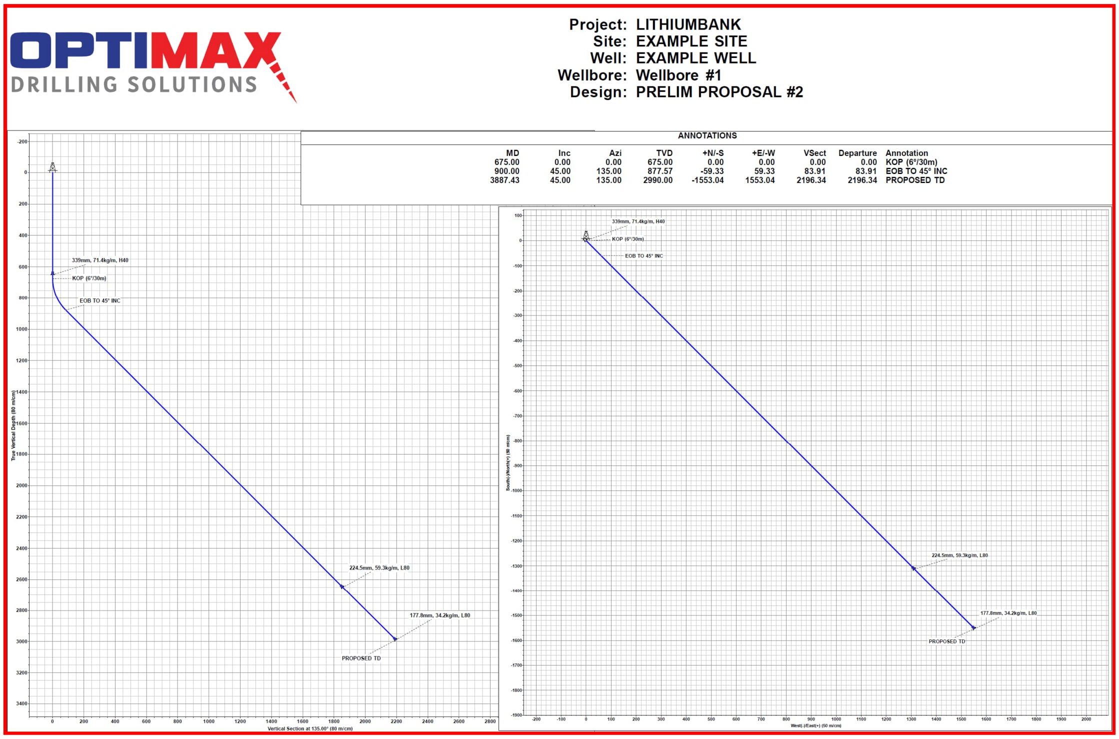


Figure 16.2: Preliminary well trajectory of a deviated well at 45°

Each well is initiated at surface from a vertical inclination, with the deviated trajectory commencing below the surface casing. The deviation, as well as the direction will be well specific and will depend on the bottomhole target.

The surface casing is planned to be set at 650 m TVD (true vertical depth), to ensure ground water protection. According to the AER BGWP (Alberta Energy Regulator Base of Ground Water Protection) lookup tool, the BGWP Elevation for this area changes between 138 m to 200 m ASL. The ground elevation is between 649 m and 768 m for well network. Based on this, the deepest BGWP is 630 m TVD. Therefore, 650 m TVD surface casing depth will meet the base of ground water protection requirement for all the wells in the current network. This is a conservative estimate and will be done on a well-by-well basis in the detailed design.

The directional kickoff is planned 25 m below the surface casing shoe to allow the directional bottom hole assembly to be outside the surface casing prior to kicking off. The build rate is planned for 6 degrees/30 m until ~45 degree hold angle is achieved. The end of directional build is approximately 900 mMD (measured depth) where the hold section begins. For each well, depending on the bottom hole location, the hold angle will change, but typically it will be less than 45 degrees above the Leduc formation. However, for each well, the directional plan is consistent with 45 degrees through the Leduc formation.

The well design to accommodate the targeted production flow rates and is recommended to be 339.7 mm (13 3/8”) surface casing, 244.5 mm (9 5/8”) for intermediate casing and a slotted liner of 177.8 mm (7”) over the Leduc formation. The slotted liner across the Leduc formation is to mitigate fines returns, but an open hole completion may also be feasible. The decision on completion technique will be made during detail design stage. The intermediate casing is expected to be set at approximately 2650 m TVD or approximately 3406 m Measured Depth (MD) depending on the deviation of each well. The expected total well depths is approximately 2990 m TVD or 3887 m MD. The casing grade specifications take sour service into account for corrosion prevention. The specifics of casing design will be determined in the next development phase once well tests confirm the composition of the produced brine water and gases.

See Figure 16.3 for a typical production well schematic showing casing strings and expected set depths for a generic production well. The drilling muds planned, and cement type are also indicated on the figure. This design may be revised as more information becomes available during the next phase of the project.

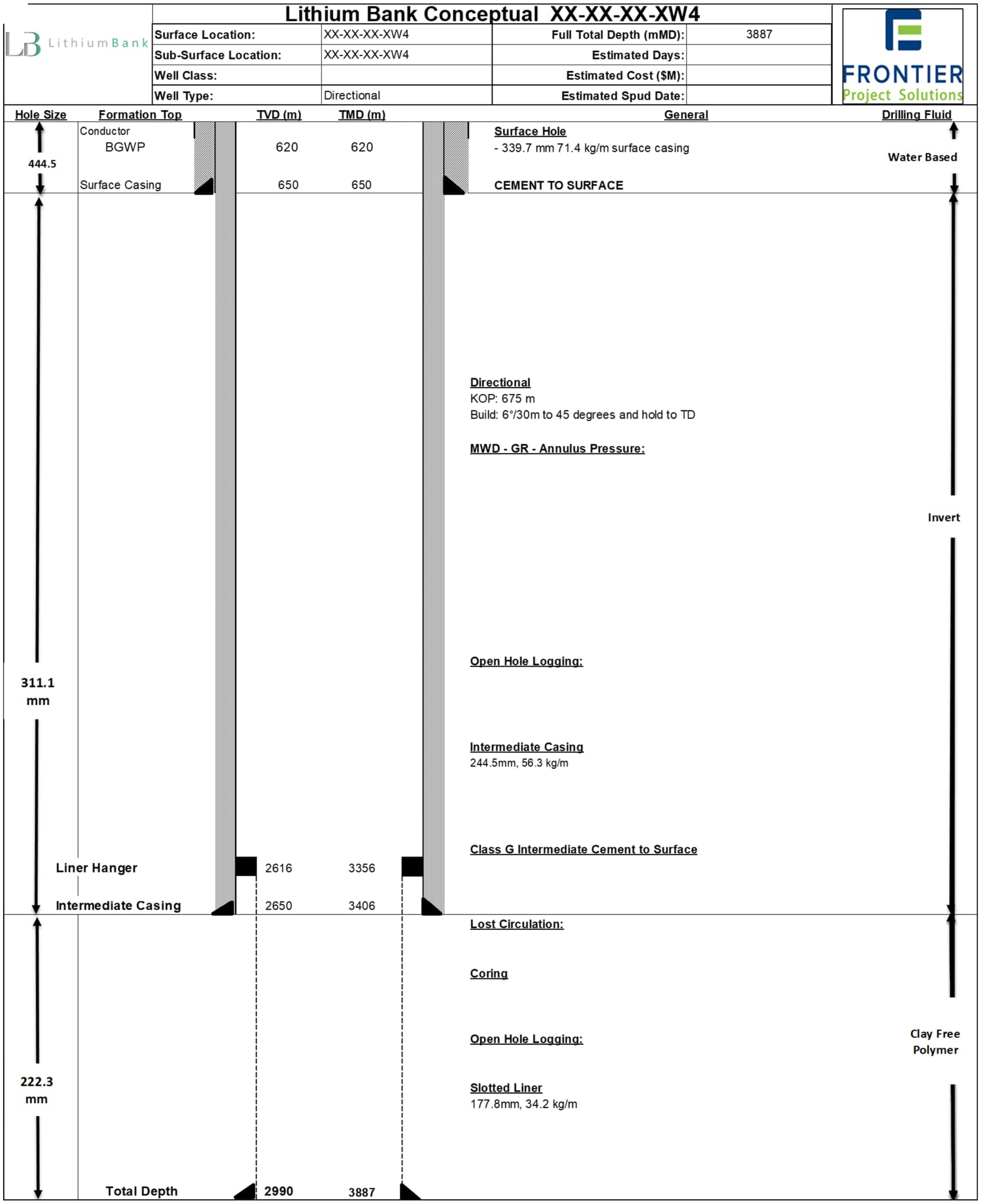


Figure 16.3: Generic Production Well Schematic

Drilling wells for lithium brine production uses the same proven practices and 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 19.9 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 well has been drilled to total depth and the drilling rig has been released. It is expected that the drilling time will see efficiencies as more wells are drilled and could get as low as 15.4 days. To achieve the full development plan of 50 production wells and 50 injection wells, a number of rigs would be employed at one time, and wells could be drilled over a number of years. Before drilling starts, civil construction is required for the construction of well pads and road access, which is taken into consideration in the well program schedule and can be optimized with concurrent activities.

The lithium enriched brine from the Leduc formation is produced 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 the production wells are 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 recommended operating range is defined for each pump stage in the catalog performance curve, which can be optimized for each well when it is in operation. Predictive analysis is done to evaluate performance, optimize operating conditions, and minimize failures.

The ESP design planned for this project will move the brine from the Leduc Formation. The ESP set depth is designed for 1000 m and will maintain sufficient pressure to flow into the gathering pipeline system to the CPF, with metering on the multi-well pad facility, at the expected average brine flow rate of 5,000 m^3/d per production well. The pumps are set above the producing interval, based on the expected aquifer flowing pressure and rate. The pump size at this project stage is assumed to be one size for each well, though the pump sizing will depend on each well geology, deliverability, and stage of life. The 1,000 m set depth is to reduce the cost of tubing and ESP cable, while also reducing friction and electrical cable losses and deep enough to ensure there is enough flowing pressure at the pump intake.

The multi-well pad 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.

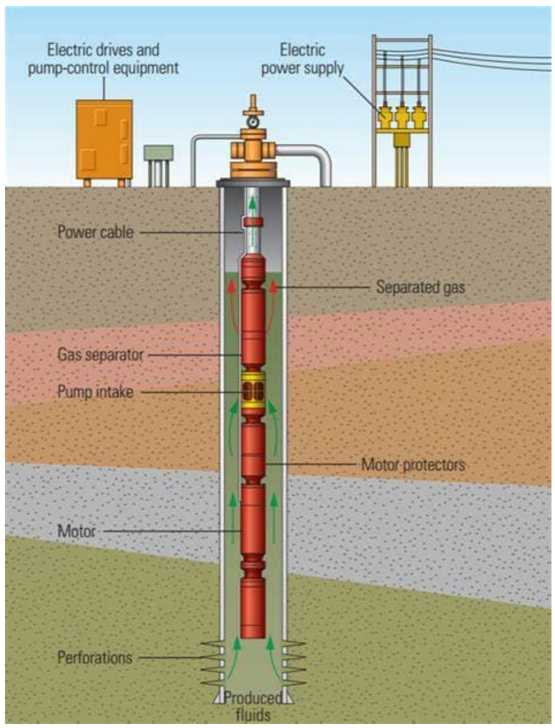


Figure 16.4: Typical ESP configuration. Schlumberger (http://www.slb.com/resource-library/oilfield-review/defining-series/defining-esp)

16.6 Injector Well Design

The lithium-depleted brine injection wells have similar well design to the production source wells with a few differences. The surface casing and intermediate casing are the same, but there will be no slotted liner for the injection wells and will be left open without a liner (barefoot completion). Additionally, no downhole Electrical submersible pump (ESP) is required on the injection wells.

The direction profile is similar to the production wells, with the surface casing set at 650 m to protect the base of ground water (conservative estimate on will be done on a well-by-well basis in the detailed design). The wells will also be drilled with an approximate max hold deviation of 45 degrees above the Leduc formation, and 45 degrees through the Leduc formation.

The surface casing will be 339.7 mm (13 3/8”) and intermediate casing will be 244.5 mm (9 5/8”) casing to allow 7” tubing to be deployed. 7” tubing was chosen to reduce friction at 5,000 m^3 per day.

From the data available at the time of this report per Table 16-2, the well diameters selected can achieve the desired injection rates.

It is assumed that 50 lithium-depleted brine injection wells will be required to handle the 250,000 m^3/d (to 255,404 m^3/day of lithium depleted brine) brine rates as per the designed Network. These would be deviated wells from 11 multi-well pads. There could be potential to reuse existing depleted oil and gas wells for injection, but this would require investigation in the next design phase.

16.7 Generic Well Pad Layout

The Well Pad Layout needs to have a few attributes to drill the well and to service the wells once in operation. The following guidelines for surface pad layout will be required for both the drilling and service rig. The guidelines will be refined in the detailed design when the drilling rig is selected.

- Inter-well spacing (Wellhead to Wellhead) 12 m apart.
  - Spacing changes with chosen rig to drill, but typically this is 12 m between wellheads (but can be as small as 5 m).
- 35 m minimum space in front of the wellheads.
  - Required for both drilling and completion rig.
- 15 m minimum space from the sides of the wellhead array to the edge of the surface lease.
- 20 m minimum space behind the wellheads for the drilling rig.
- 7 m to 10 m space between wellhead and permanent pipe rack (that is, 7 m to 10 m of removable flowline to allow service rig to fit).

The preparation of the surface pad will be constructed prior to the drilling rig arriving so that the pad does not need to be built multiple times. Once drilling is completed the final grade of the pad can be leveled, and the piping connections can be made to the installed wellheads.

The diagram below shows a generic layout with 4 wellheads, but this can vary depending on how many downhole targets are accessible for the well pad surface location. This type of wellhead and pad layout is similar for both production and injection wells.

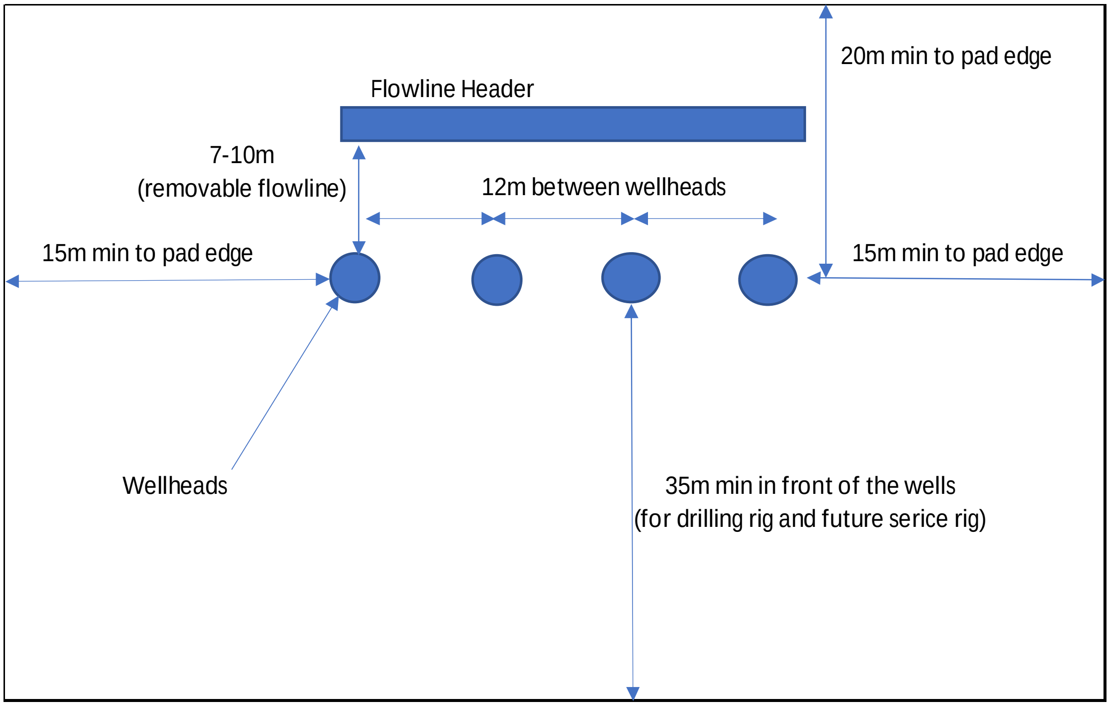


Figure 16.5: Generic Well Pad layout

16.8 Number of Well Pads

The number of well pads and location of the well pads is based on the directional plan. The number of well pads is minimized to reduce capital costs and environmental impact.

On the following chart, the well 'dots' (blue and orange dots) are the planned MPP (midpoint of perforations) point in the Leduc formation. The UTM (Universal Transverse Mercator coordinates) location of the top of the Leduc is unknown at this time because we do not have a fixed azimuth for the wells yet. Therefore, the well pad locations are based on the MPP locations.

The circle radius on the chart is 1750 m (representing that we can reach 1750 m from the center of the circle). The departure measurement from top of Leduc to surface using a 45 degree well profile is roughly 1850 m and the departure distance to MPP is roughly 2000 m. Therefore, using 1750 m radius circles is conservative, but it allows for turning or other directional controls in the future to line up a consistent azimuth for all the wells in the Leduc and it allows movement of the pads for ground conditions. A more aggressive departure distance per pad may be chosen in the detailed design stage.

Based on the 1750 m radius well pads, 12 production well pads and 11 injection wells pads (for total of 23 multi-well pads) were chosen as shown in the chart below. The green star is the well pad center. A preliminary ground review did not show much terrain or lakes in the area but will be fully reviewed in the detailed design stage.

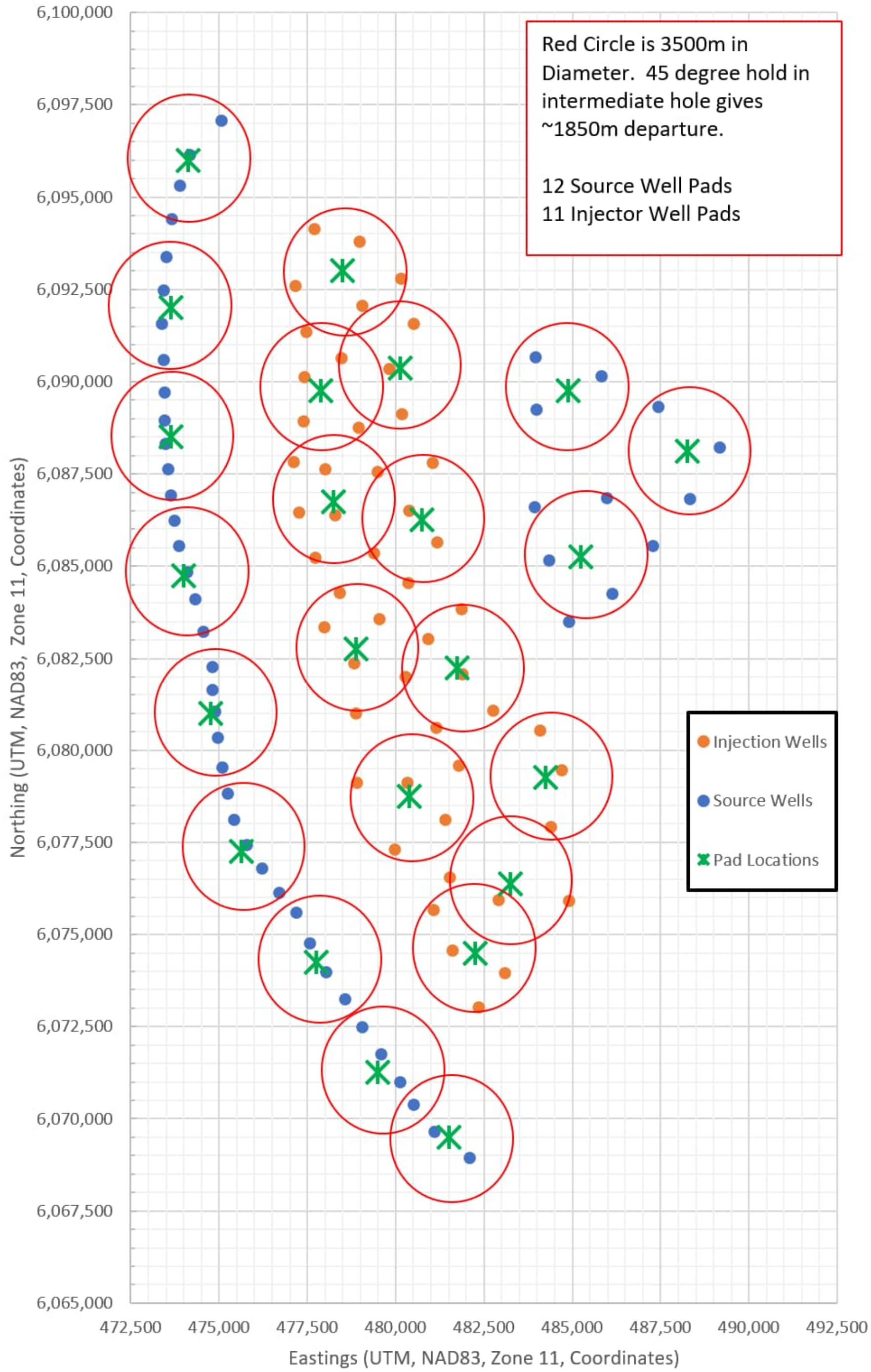


Figure 16.6: Proposed Well Pad Locations and the locations of 50 source wells and 50 injection wells

16.9 Well Related Power Consumption

The power consumption of the down hole ESPs for the production wells was estimated based on vendor specifications for the pump selected. The downhole ESPs, to lift 5,000 m^3 of brine from 1,000 m depth to surface will use roughly 1.0 MW each for a total of 50 MW.

16.10 Well Delivery Schedule

To drill, case and complete 50 Brine Production Wells and 50 Brine Injection wells, it will take approximately 1987 rig days as per table below. It is assumed 3 drilling rigs will be used to complete the program which would accelerate the program to 2 years. This drilling timeline excludes the time to prepare the surface lease and road access, which would occur before the rig moves onto the surface pad.

Table 16-2: Summary of Drilling Rig days required to complete full well network program.

Type of Drill Activity	Avg days/well	# of wells	Total Days
Production Wells	20	50	995
Injector Wells	18	50	900
Interpad rig move	4	23	92
		Total Rig Days	1987
		Total Rig Years - 3 Rigs	2

16.11 Well Operating Considerations

Many factors need to be taken into consideration for the operation of the lithium brine well network. Safety of the operation and environmental protection are key considerations. Below is a list of risks and potential mitigations for operating the well network:

Pump failure

- ESP stops working or becomes too inefficient. Or shaft failure occurs.
- Replace pump.

Sour gas production

- Production of sour gas occurs to surface. Can pose safety concerns. Can cause increased corrosion risk.
- Understanding composition of gas and fluids early in design phase will enable well and facility design to accommodate the sour components. Conducting a flow test and compositional analysis of the produced fluids and gas in a test well located within the project area will help to understand and mitigate the risk of sour gas production.

Casing vent leak

- It is possible to have a leak of gas through the surface casing. This gas can be biogenic from close to surface formations or from hydrocarbon bearing formations deeper.

- The well design incorporates installation of casings and cement to mitigate leaks. If a leak is detected, remedial action can be taken to determine the source of the leak and plug it off.

Hydrocarbon production

- Since the Leduc is a hydrocarbon bearing formation, it is possible that the brine fluid contains some oil. If the facility is not designed to handle any oil this may cause some production issues in brine handling.
- Conducting a flow test during the design phase from a test well within the project area will help to understand the fluid composition and mitigate this risk in the design.

Spills on surface at wellpad

- It is possible for spills to occur at surface from the wellhead, surface piping, production vessels, or chemical systems.
- A spill management plan and leak detection and containment system are recommended to mitigate these types of risks, depending on the wellpad equipment.

Impaired production/injection flow rate

- Brine production flow rate is lower than expected from a well, which can occur at any time during the production life. A sudden reduction or increasing reduced rate can be indicative of a blockage at the liner.
- An evaluation of the cause of the reduced flow is needed and remedial action can be taken in the form of a workover, acid service or other measure.
- It is possible that an additional injection well will be required if the total injection stream flow rate is impaired or is higher due to increased water use in the process. The cost for this well is not included in the well network plan for this PEA.

Sediment production

- Production of solids, fines or sediment can plug the surface facilities or cause increased risk of corrosion.
- The slotted liner design should be based analysis of the formation rock based on core sampling and particle size distribution.

Scale production

- Scale can buildup on the down hole tubulars, making workovers inefficient and can plug off the completion.
- Chemical remediation may be required at fixed intervals to reduce scale buildup.

Injectivity impairment

- Scale can develop across the injection interval at the sandface and restrict injectivity. This can be caused by sediment/fines in the injection fluid or incompatibility of injection fluid with the insitu fluids/rocks. This can be mitigated with pre-filtering before injection.
- Salt precipitation in the injection wells can occur if the water quality of the injection stream is incompatible with the formation water.
- Bacteria or other introduced components in the injection fluid can result in biochemical reactions that cause flow impairment in the injection system which can affect surface piping, sandface, and within the reservoir. Analyzing the fluid composition and introduction to any foreign components during the fluid processing, if sent to a surface pond, needs to be done in the design phase to develop mitigation programs. Mitigation can include change to process system to reduce contact with foreign components, or to introduce a biocide program or similar preventative program.

16.12 Well Network Next Steps

At this preliminary project stage, the design is based on the best available information. In order to refine the design parameters for the well network, it is recommended to gather project specific data from a well within the project area. This would include obtaining and analyzing core across the Leduc Formation to determine reservoir characteristics specific to this project, to take fluid samples of the Leduc brine, and to conduct a flow and injectivity test. The core analysis should include a particle size distribution to determine completion design.

The objective of fluid sampling is to confirm lithium concentrations, and analysis of gas and fluid compositions to determine H_2S and other component concentrations. The objective of the flow and/or injectivity tests is to confirm productivity and transmissivity of the formation. It is recommended to conduct discrete flow tests, to isolate vertical sections of the Leduc to determine if there is a variability in permeability and lithium concentrations throughout the formation. This will help to determine completion design and efficient operating strategies.

Testing of the fluid compatibilities should be conducted for the injection stream to ensure the blended depleted brine and is compatible with the reservoir rock and reservoir fluids.

The flow test should be conducted with pressure and temperature bottomhole recorders near the Leduc Formation in order to evaluate the pressure changes during flow or injection and conduct a buildup or drawdown pressure analysis to determine reservoir characteristics. During the flow test, it is recommended to record pressures in an adjacent well (distance to be determined but 100’s meters distance) completed in the same interval as the flow test. This will provide spatially averaged reservoir characteristics for the well network design.

It is possible that lithium-brine production from the Leduc, and injection of lithium-depleted brine can be achieved by re-entering existing oil and gas wells. Once it is confirmed that any such existing wells are proximal to the infrastructure planned for this project, it is recommended that a study be conducted to determine suitability including but not limited to wellbore integrity, well age, well depth, well history, wellbore size, existing completions. Even if the wells are shallower than required, it is possible that they could be deepened. A cost analysis would be completed to determine the potential savings over drilling new wells.

A large part of the cost for the project is drilling large diameter wellbores to accommodate the pump sizes needed to achieve the desired production flow rates. If smaller ESPs could be utilized, then the wellbore sizing could be reduced, saving a substantial amount of capital and time in the schedule for drilling. It is recommended that consideration be given to commissioning a joint industry technology development study to look at the feasibility of developing smaller diameter pumps capable of delivering a similar flowrate. Such a design would also be beneficial to geothermal projects, which also require large brine flow rates to meet economic hurdles. It is possible that funding or grants are available to develop such pump designs to develop elemental metals supplies and low carbon energy solutions.

17. Recovery Methods

17.1 Introduction

The Lithium Processing facility is designed for a nameplate production of approximately 34,252 metric tonnes per annum of battery grade lithium hydroxide monohydrate (30,168 metric tonnes per annum LCE) processing a feed brine throughput of 250,000 m^3/d at an average concentration of 70.1 mg/L. The operating factor considered in the process is 90%. The overall lithium recovery is estimated to be approximately 98%, considering the high DLE circuit recovery as specified by Go2Lithium.

The key steps to upgrade the lithium and produce battery grade LHM for the proposed process are:

- Brine pre-treatment.
- Direct lithium extraction.
- Impurity removal.
- Lithium electrochemical process.
- LHM crystallization.

A conceptual schematic of LithiumBank's overall lithium production process is shown below in Figure 17.1.

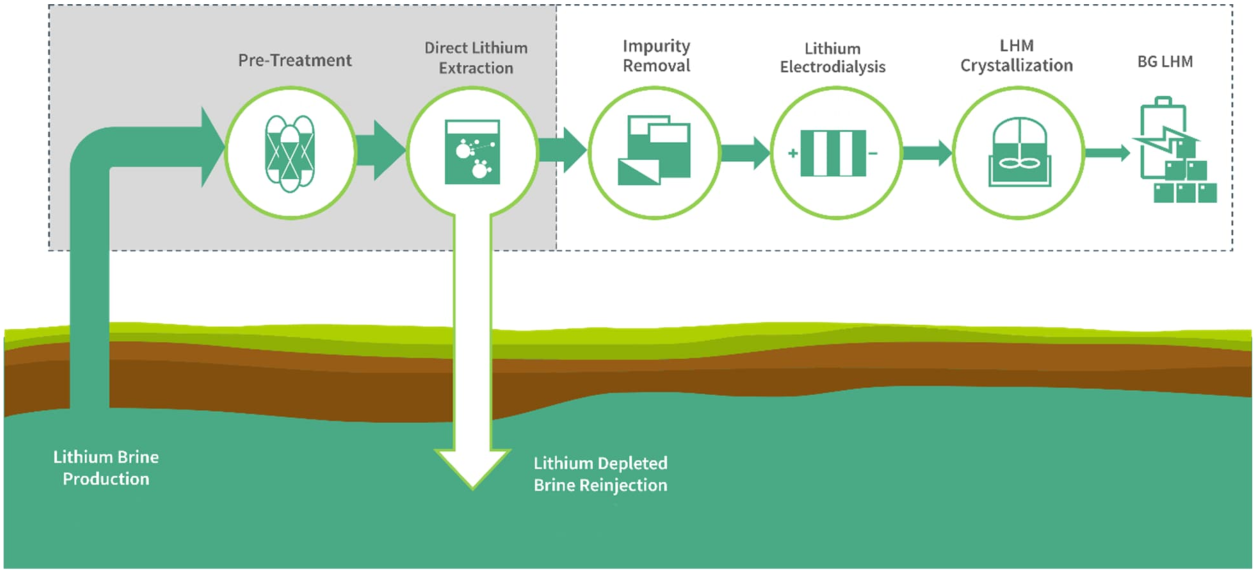


Figure 17.1: Conceptual Schematic of LithiumBank's Overall Lithium Production Process

17.2 Process Description

17.2.1 Brine Feed

The brine extracted from the production well pads is transported through a network of transfer pipelines to the central processing facility (CPF) for lithium extraction and processing.

17.2.2 Brine Pre-treatment

The raw brine delivered from the production wells contains dissolved H_2S ranging from 165 to 350 mg/L. An H_2S removal circuit is included in the design to significantly reduce the H_2S content in the brine to levels that are safe for the operating facility prior to feeding the downstream preconditioning and DLE circuit.

Total suspended solids (TSS) and total organic carbon (TOC) reduction is required to reduce fouling of the downstream DLE process. The proposed treatment technology for TSS and TOC reduction is nutshell filtration (NSF). NSF is a proven technology for treating oil field brines to reduce TSS and insoluble hydrocarbons (oils). The NSF process is not effective at removing dissolved organics and hydrocarbons. Based on the brine sampling data, dissolved hydrocarbons such as benzene, toluene, ethylbenzene, and xylene (BTEX) are not present at concentrations of concern. The brine sampling data indicate that the majority of the hydrocarbons in the brine are comprised of diesel range organics (DRO) to residual range organics (RRO) with carbon ranges of (> C_{10} to C_{50}). The NSF process is expected to remove the majority of hydrocarbons in this range.

Following the H_2S removal process, the brine will be pumped to the NSF system. The NSF system consists of pressurized filter vessels using a layer of crushed walnut or pecan shells as the filtration media. The nut shells have a high affinity for attracting and capturing oil particles and other suspended solids. Once the media bed is loaded with oil and solids, the vessels are taken off-line one at a time for backwashing to clean the media bed. The dirty backwash water will be sent to a dewatering system to separate solids and oils for disposal.

The filtered water from the NSF system will be collected and then fed to the downstream Direct Lithium Extraction (DLE) process.

17.2.3 Lithium Extraction

The pre-treated brine from the upstream process is fed to the DLE circuit which preferentially recovers lithium from the other constituents in the brine to generate a product solution that has a higher lithium concentration and lower impurity profile compared to the feed brine. This lithium extraction process is a critical step in upgrading the lithium concentration, reducing the processing volume and rejecting most of the impurity ions for downstream processing. The rejected lithium depleted brine is reinjected into designated wells.

The DLE circuit consists of four typical steps in each cycle: (1) lithium loading, (2) loaded sorbent washing, (3) lithium elution, and (4) eluted sorbent washing (Figure 17.2). During the lithium loading step, lithium is selectively loaded onto the sorbent over the other remaining constituents. As lithium is loaded, protons are released, and an alkali is required to maintain the pH at the optimal level. A counter-current reactor configuration allows the sorbent to leave the circuit with high lithium uptake, while the brine exits with lithium depleted. The loaded sorbent is then washed to remove the entrained impurity ions. Following this, lithium is eluted in an acidic solution at a low pH, and a counter-current configuration results in efficient elution to a low residual lithium concentration on the sorbent and a concentrated eluate. By using sulfuric acid for elution, further rejection of calcium, strontium, and barium is achieved by precipitating these elements as sulfates. The eluted sorbent is washed so that it can return to the loading step to extract lithium, while the final lithium rich eluate solution is filtered to remove the precipitated impurities and sent forward for removal of the remaining impurities.

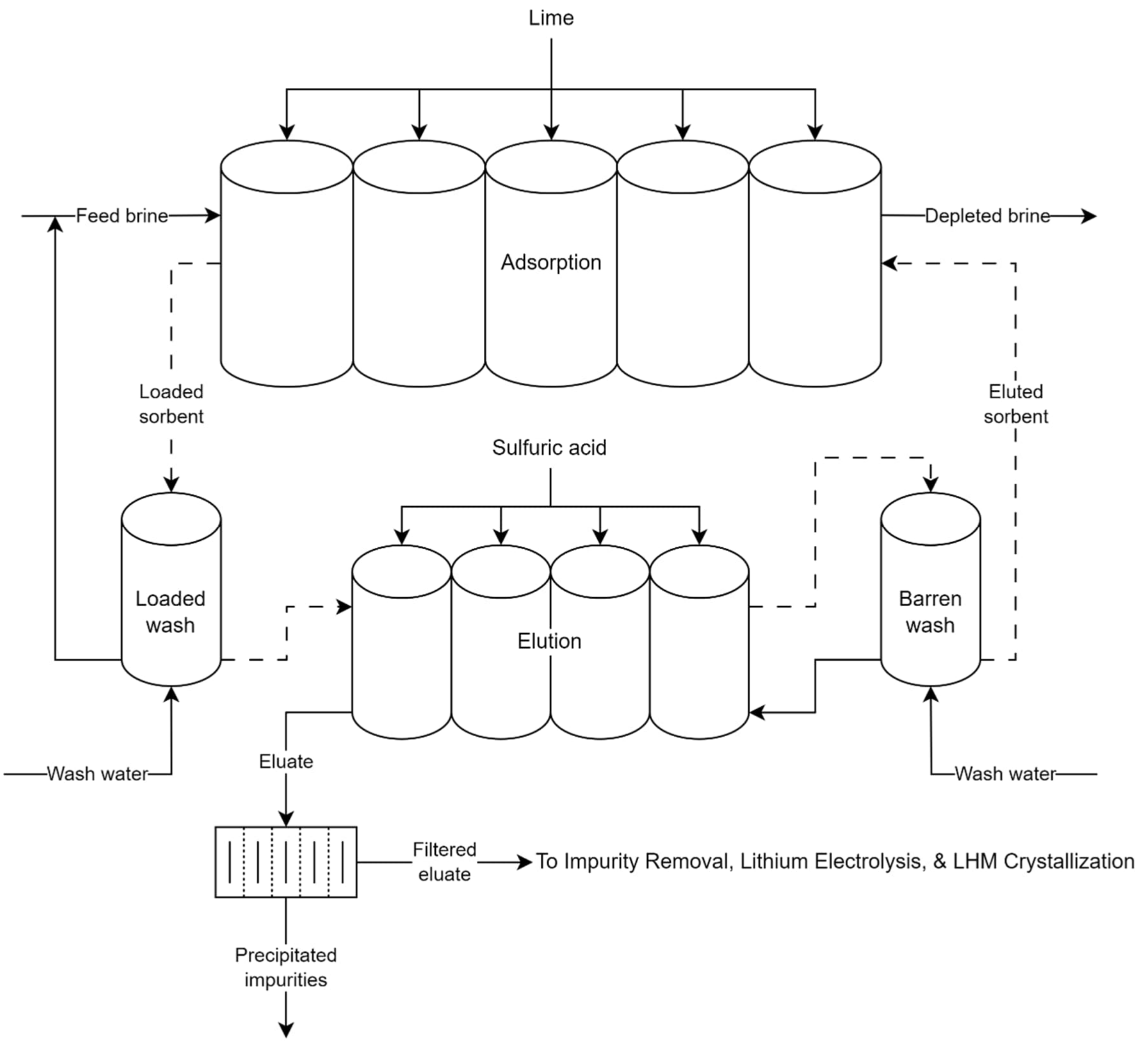


Figure 17.2: Conceptual flowsheet for DLE (solid lines represent solution flow, broken lines represent sorbent flow)

17.2.4 Impurity Removal

The eluate solution contains some trace impurities which have to be removed in order to produce a battery-grade product. The eluate solution is neutralized and pre-conditioned prior to feeding reverse osmosis to concentrate the solution.

The concentrated lithium solution is further refined using ion exchange. The polished lithium solution is sent to the lithium sulfate electrochemical process to produce lithium hydroxide.

17.2.5 Lithium Sulfate Electrochemical process

The lithium concentrate solution is treated in the lithium sulfate electrochemical process where lithium hydroxide is formed, and dilute sulfuric acid is regenerated for use in the upstream process. The base product solution containing mainly lithium hydroxide, and some impurity constituents, is sent to the lithium hydroxide crystallization circuit for further processing.

17.2.6 Lithium Hydroxide Monohydrate (LHM) Crystallization

The base product solution is sent to a two-stage crystallization process where the crude LHM crystals formed in the first stage are separated from the mother liquor that contains some other impurity constituents. The crude LHM crystals are digested and processed in another stage of crystallization to produce higher grade LHM which meets the requirements for downstream battery material production. The purified LHM crystals are washed and dried. LHM product from the dryer is maintained in a carbon free and moisture-free environment and transferred to the product packaging system. The bagged LHM product is directed to storage for delivery to the market.

17.3 Process Block Flow Diagram

Figure 17.3 shows a simplified process block flow diagram for the lithium extraction processing plant.

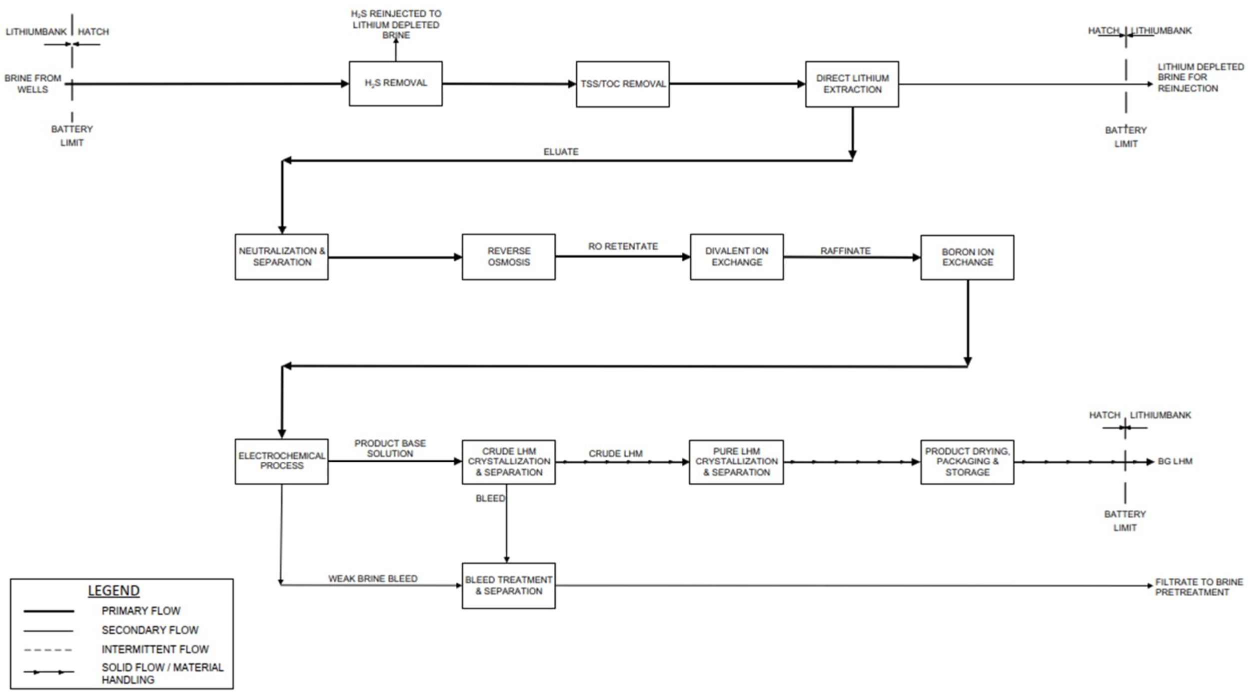


Figure 17.3: Simplified block flow diagram of lithium extraction processing plant

18. Project Infrastructure

18.1 General

The Boardwalk Project is located directly south and west of the Town of Valleyview and 270 km northwest of the City of Edmonton. It can be accessed year-round by road, as described in Section 5.1.

An overall map regarding the infrastructure of the Boardwalk Project can be seen below in Figure 18.1. The yellow indicators represent the location of the supply well pads and the blue indicators represent the location of the injection well pads. Located centrally to the supply/injection well pads are the CPF and Power Plant. Between each of the well pads and CPF is a pipeline network which transfers the brine to/from the CPF.

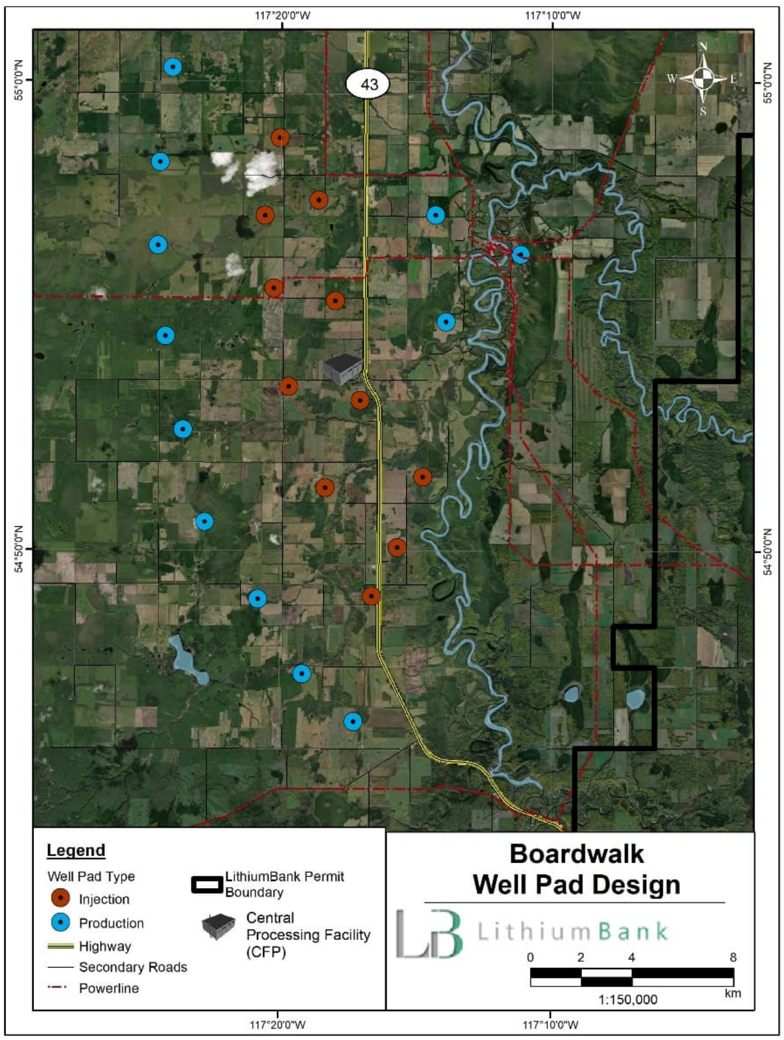


Figure 18.1: Overall Map of the Infrastructure of the Boardwalk Project including Wells and CPF

As indicated on the above figure, The Boardwalk Property consists of the following main infrastructure:

- Well pads (well pads and associated the infrastructure related to the subsurface equipment and infrastructure is described in Section 16).
- Surface Brine and Injection Supply Infrastructure (surface piping infrastructure from production well pads to CPF, injection surface piping and surface pumps).
- Central Processing Facility.
- Utilities.
  - Power
  - Raw Water.

The infrastructure related to the supply/injection pads and CPF/Power plant indicated on the above figure is described in the following sections.

18.2 Surface Brine Supply and Injection Infrastructure

18.2.1 Surface Brine Supply Infrastructure

Approximately 5,000 m^3/day of brine will be produced at each production well head, with 50 wells distributed across 12 production well pads within the network. In total, 250,000 m^3/day of brine is produced and sent to the CPF.

The total length of production piping required for the brine supply to CPF is approximately 80 km. The pipeline material selected was fiberglass due to its high corrosion resistance to the hot brine.

18.2.2 Surface Brine Injection Infrastructure

Approximately 5,100 m^3/day of brine will be sent from the CPF to each injection well, with 50 injection wells distributed across 11 injection pads within the network.

The total length of piping required for the brine injection from the CPF to the injection well pads is approximately 40 km. Fibreglass was also assumed for piping materials between the CPF and the injection well pads.

The horizontal multistage centrifugal surface pump was used for injecting the lithium depleted brine in the well heads received from the CPF. There will be one pump per well, for a total of 50 pumps.

18.3 Central Processing Facility Infrastructure

A conceptual layout of the Centralized Processing Facility is provided below in Figure 18.2. The overall footprint of this facility is approximately 210,000 m^2.

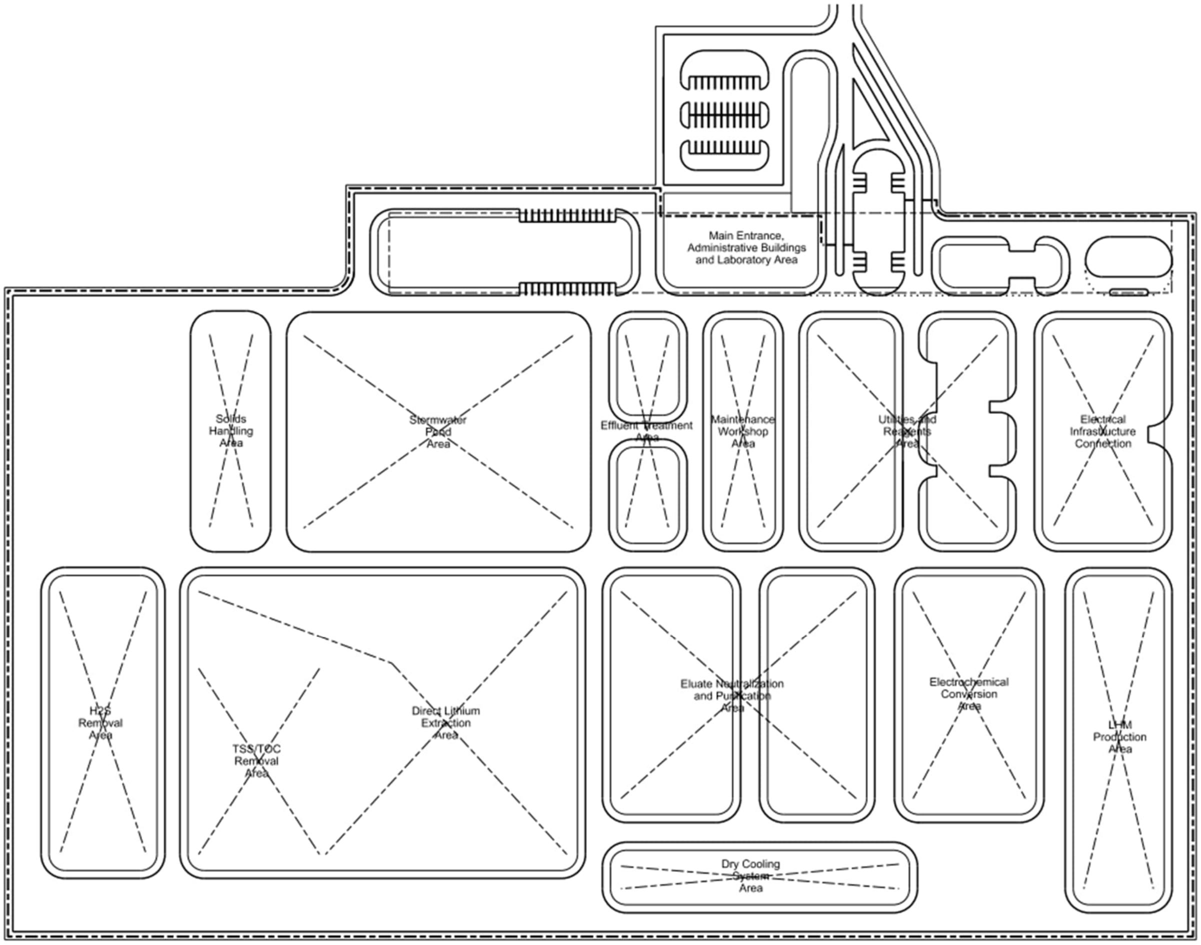


Figure 18.2: Central Lithium Processing Plant Conceptual Layout

As seen in the above figure, the CPF consists of the main process facilities, as well as process related facilities such as:

- Water treatment, storage, and distribution.
- Reagents make up, storage and distribution.
- Electrical tie-ins from the on-site power plant.
- Other utilities such as compressed air.

The auxiliary facilities included are described in the following section.

18.3.1 *Auxiliary Facilities*

The CPF will include the following auxiliary infrastructure facilities:

- Access/Security Checkpoint – Gate house
- Internal Access Roads
- Emergency Response
- Fire water system
- Parking
- Fuel loading stations
- Stormwater pond
- Perimeter fence
- Non process buildings:
  - Administrative Office and Laboratory
  - Warehouse(s)
  - Workshop(s)
  - Shipping and receiving

18.4 Raw Water Supply Infrastructure

The water is expected to be sourced from a combination of surface water (Little Smoky River, 80% of supply) and groundwater (20% of supply) from the Little Smoky Watershed. The main water source is the Little Smoky River.

The key water supply components include:

- River water intake structure.
- River intake water pump.
- Surface water transmission pipeline.
- Water storage.
- Groundwater wells.

The water storage includes a large water pond which has been considered to mitigate the risk of water shortage events. Storage is most likely to be required during the winter period when surface water cannot be accessed from the river, and during drought periods. Groundwater wells are another important component of LithiumBank's water supply plan, to be utilized during winter months when river diversions are restricted.

The raw water is filtered and then utilized within the CPF for some applications directly. For most other uses, the filtered raw water will be pre-conditioned and treated before being used within the process.

18.5 Natural Gas Supply Infrastructure

The Boardwalk Plant will require approximately 23,070 GJ/day of fuel to supply to the 2 LM6000 PF+ gas turbines. The natural gas supply will be coming from the NGTL system, which has 2 – 24" laterals to the Sturgeon Lake Sales point. The interconnection to the NGTL pipeline will likely be near 54.91N, -117.28W. A hot tap, meter station, pressure regulation and related appurtenances will have to be established by NGTL in order for gas flow to begin. The direct connect pipeline will likely be 12" high carbon steel with an MAOP of ~6,200 kPa. The direct connect pipeline will be approximately 10 km.

18.6 Power Infrastructure

The Boardwalk Plant will have a power demand of approximately 167 MW. The power for the Boardwalk Plant will be provided from two sources, and will service the facilities as follows:

- AESO (Alberta Electrical System Operation) Electrical Grid.
  - Transmission lines will service wells in the most east and southern locations, for a total demand of 35 MW.
- On-site power generation facility.
  - The on-site power generation facility will service the CPF and the remaining wells in the western and north-west locations, for a total demand of 132 MW.

The on-site power generation facility will include two gas turbines, expected to be GE LM6000 PF+ aeroderivative gas fired turbines. Each generator will produce power at 13.8 kV. Additional infrastructure includes:

- Once Through Steam Generators
- Steam Turbine
- Balance of plant (feed pumps, tanks, etc.)

From the on-site power generation, the power will be stepped down and utilized in the CPF and western and north-west wells.

19. Market Studies and Contracts

19.1 Lithium Demand

Lithium-ion battery demand has grown substantially in recent years as electric vehicle (EV) adoption has strengthened and energy storage systems (ESS) have grown in popularity. EV batteries are forecast to become the primary driver for lithium chemical demand, with Wood Mackenzie[1] projecting demand in 2032 to be over twelve times higher than 2020 levels, as shown in Figure 19.1. EV demand growth is expected from passenger vehicles, with global sales forecast to increase 22% per year from 2020 to 2030[2].

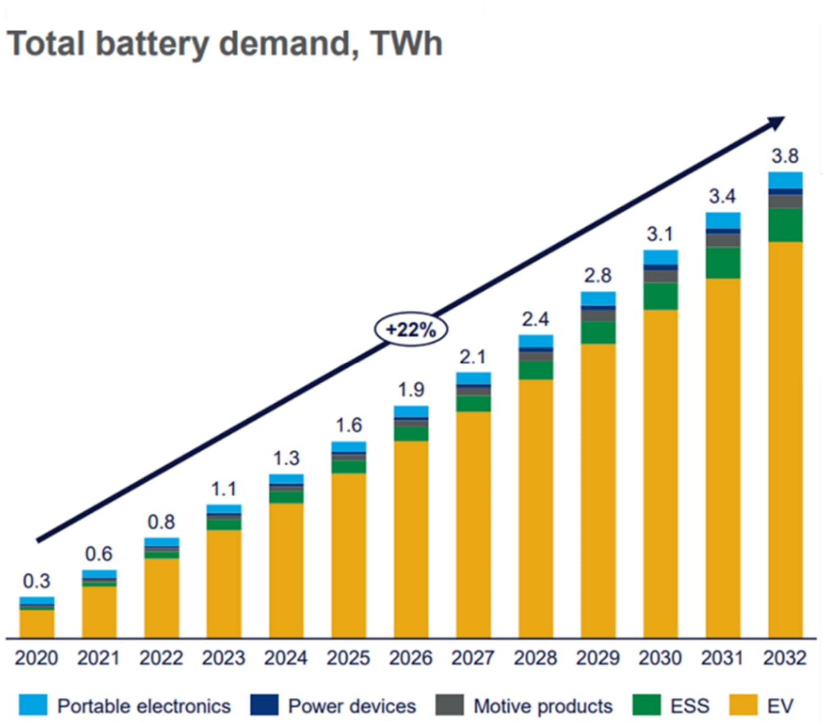


Figure 19.1: Total Battery Demand by End-Use (TWh) (Wood Mackenzie, 2022)[3]

[1] The data and information provided by Wood Mackenzie should not be interpreted as advice and you should not rely on it for any purpose. You may not copy or use this data and information except as expressly permitted by Wood Mackenzie in writing. To the fullest extent permitted by law, Wood Mackenzie accepts no responsibility for your use of this data and information except as specified in a written agreement you have entered into with Wood Mackenzie for the provision of such data and information.

[2] The foregoing information was obtained from Lithium market 2021 outlook to 2050™, a product of Wood Mackenzie

[3] The foregoing chart was obtained from Battery & raw materials – Investment horizon outlook to 2032 (Q4 2022)™, a product of Wood Mackenzie

The cathode active materials (CAM) and precursor cathode active materials (pCAM) that are used in lithium-ion batteries in today's EVs are dominated by nickel-rich NMC cathode chemistries which require battery-grade lithium hydroxide. Wood Mackenzie forecasts this market will shift to adopt larger volumes of non-nickel-rich Lithium Iron Phosphate (LFP) chemistry (Figure 19.2), which uses battery-grade lithium carbonate. Despite this shift, the threefold increase in battery-grade lithium carbonate is forecast to be outpaced by a fivefold increase in demand for battery-grade lithium hydroxide over 2022 to 2032. Together, battery-grade lithium carbonate and battery-grade lithium hydroxide made up 72.1% of total lithium chemical demand in 2021 and will likely dominate long-term demand for lithium chemicals as demand for EVs increases.

The largest end-use market for lithium-ion batteries in the automotive sector is currently Asia Pacific, dominated by China, followed by Europe and North America. This is not expected to change dramatically, with Wood Mackenzie estimating that by 2032 Asia Pacific will account for about 50% of total demand, followed by Europe and North America at about 35% and 15%, respectively. CAM and pCAM manufacturing from lithium chemicals is mainly located in Asia Pacific but gradual expansion in Europe and North America is underway to support local lithium-ion battery supply chains.

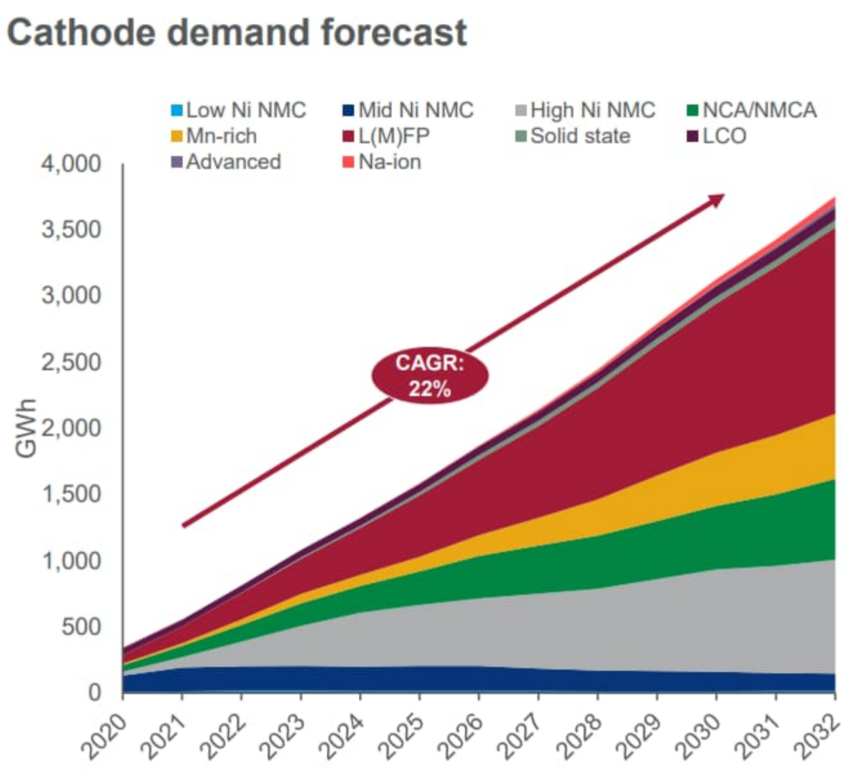


Figure 19.2: Cathode chemistry demand forecast (Wood Mackenzie, 2022)[4]

[4] The foregoing chart was obtained from Battery & raw materials – Investment horizon outlook to 2032 (q4 2022)™, a product of Wood Mackenzie

Figure 19.3 shows the projected demand for lithium hydroxide in the United States for pCAM/CAM manufacturing. By 2030, the amount is approximately 200 kt LCE, equivalent to approximately 230 kt lithium hydroxide. Proposed locations for these facilities are in states such as Tennessee, Texas, and South Carolina.

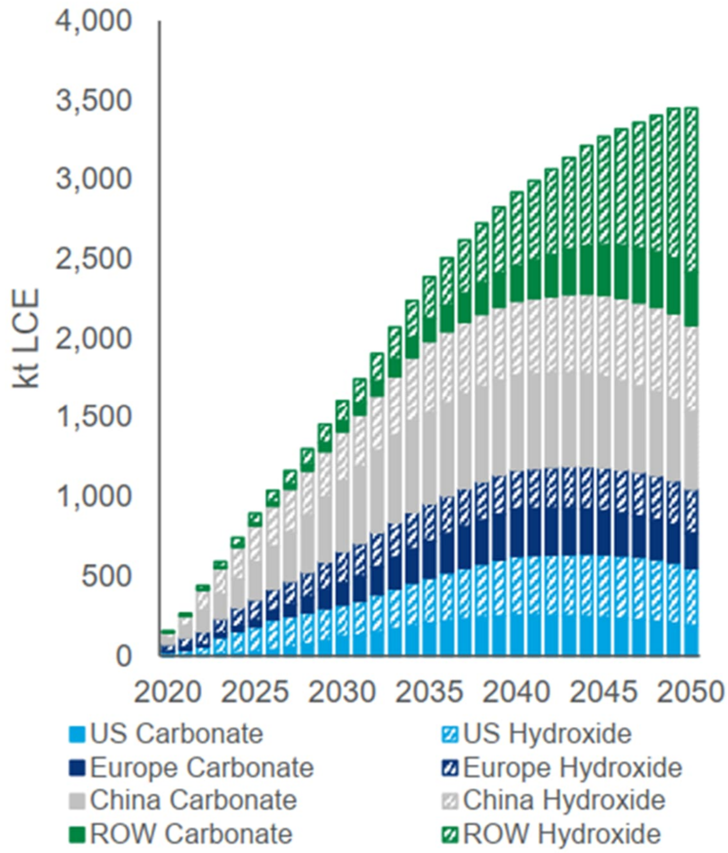


Figure 19.3: Refined lithium demand forecast for EVs (Wood Mackenzie, 2023[5])

19.2 Lithium Supply

Lithium is primarily mined from hard-rock (spodumene, petalite, lepidolite) and brine deposits. Australia is currently the global leader in mine capacity and mineral concentrate production from hard rock. In 2022 it accounted for 43% (323 kt LCE) of global lithium extraction. The Greenbushes mine in Australia alone has a production capacity of 181.5 ktpy LCE and is the largest lithium mine in the world. South America was the second largest lithium producing region in 2022, accounting for 31% of global extraction (233 kt LCE). In this region, lithium is mainly extracted from brine ponds (salars) in Chile and Argentina. For instance, the Salar de Atacama in Chile contains one of largest proven brine reserves in the world, accounting for

[5] The foregoing chart was obtained from Electric Vehicle & Battery Supply Chain – Strategic planning outlook to 2050 (March 2023)™, a product of Wood Mackenzie

about 35% of global brine deposits, and produced approximately 200 kt of LCE in 2022. China is third largest producer accounting for 24% (180 kt LCE) of global mine production but leads in global refining of lithium carbonate and lithium hydroxide with 66% (503 kt LCE) of global capacity.

Brazil and Portugal are also important lithium miners but extract lithium from relatively smaller deposits. Canada is extracting lithium from one mine with all the processing done in China. Zimbabwe produced some concentrate in the past and has projects that may come online soon, however, an export ban for lithium concentrate was implemented in December 2022 to encourage the start-up of local refining capacity.

Figure 19.4 shows a global breakdown of lithium extraction and conversion for 2022 and an estimate for 2032.

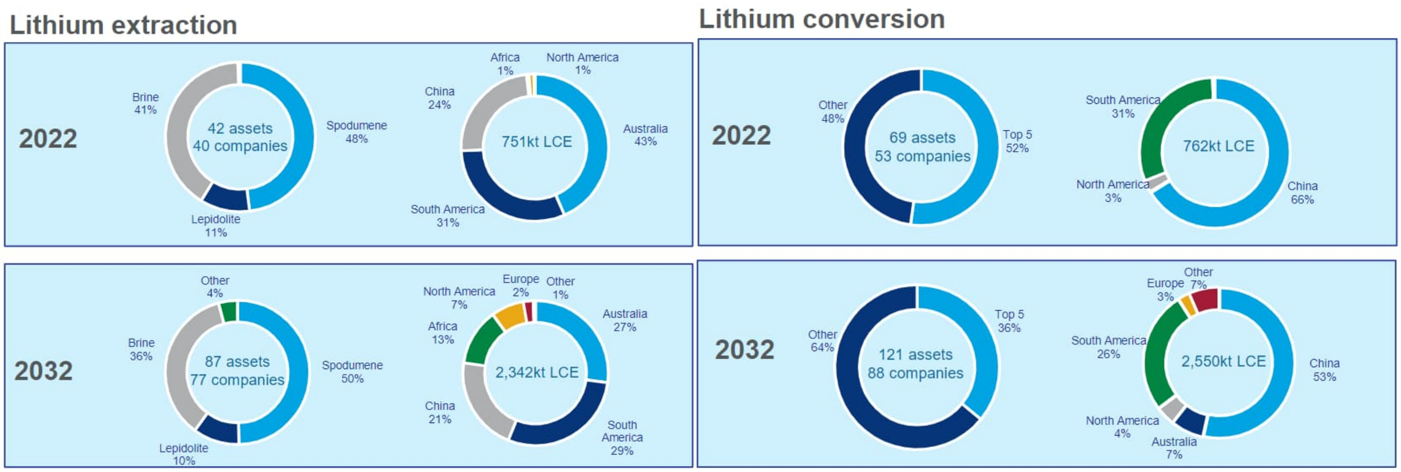


Figure 19.4: Lithium extraction and conversion estimates by region for 2022 and 2032 (Wood Mackenzie, 2022)[6]

Mine capacity is expected to increase dramatically in the next decade to respond to increasing lithium chemical demand. Australia is projected to continue being the largest supplier of mineral concentrate. China is forecast to remain the largest supplier of lithium chemicals, including battery-grade lithium hydroxide, given its significant conversion capabilities.

Primary lithium capacity expansion is expected in the Democratic Republic of Congo, Mali, the United States, Canada, Argentina, and Serbia, with commissioning of new lithium projects anticipated within the next five years.

Wood Mackenzie estimates that this increased supply growth will result in a short-term oversupply of lithium between 2023 and 2027 (Figure 19.5). As demand catches up

[6] The foregoing chart was obtained from Global lithium investment horizon outlook – Q4 2022™, a product of Wood Mackenzie

afterwards the supply deficit will support lithium prices to encourage project development and capacity expansion.

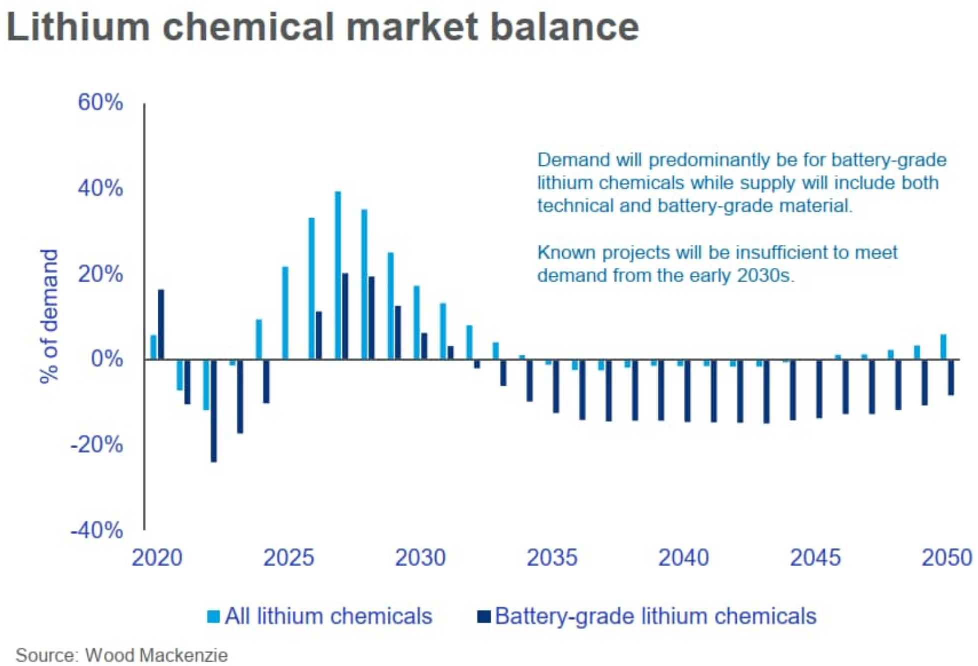


Figure 19.5: Lithium chemical market balance (Wood Mackenzie, 2022)[7]

19.3 Prices

From 2015 to 2021 the average annual battery-grade lithium hydroxide price ranged from US$11,000-18,000/t for contract pricing and US$7,300-27,000/t for spot pricing. In 2022, the average annual price increased to roughly US$60,000/t (spot) and US$41,000/t (contract), while in 2023 spot prices fell to $33,000/t and contract prices rose to $48,000/t. In January 2024 the average spot price was in the range of US$17,000/t.

This study uses as a long-term battery-grade lithium hydroxide price of US$26,000/t, based on a price analysis of forecasts from Project Blue and Consensus Economics. This price is reasonably consistent with other publicly issued economic assessments. The sensitivity analysis in Section 22 Economic Analysis considers the impact of variations in the price environment on project economics.

[7] The foregoing graph was obtained from Global lithium investment horizon outlook – Q4 2022™, a product of Wood Mackenzie

20. Environmental Studies, Permitting and Social or Community Impact

20.1 Environmental Permitting and Regulatory Requirements

Due to lithium brine production wells being a relatively new technology in Alberta and throughout Canada, environmental considerations, and regulations specific to lithium production are still in the early stages of implementation. LithiumBank's proposed Boardwalk project is expected to require a variety of environmental permits and regulatory approvals under municipal, provincial, and federal legislation. Environmental regulatory approvals and permits associated with LithiumBank's boardwalk project will be related to construction, operation and closure of the processing facility and extraction of brine from the Leduc formation.

As part of this PEA, a preliminary analysis and determination of the required permits and regulatory approvals that are required for the development of the Project has been conducted. Provided below is a list of the major environmental regulators that have been identified as being associated with regulating the development of the proposed Boardwalk project. Additionally, information regarding the scope of each regulator's role in regulating the project is provided along with the potential significant regulatory requirements that may be required.

20.1.1 Alberta Energy Regulator (AER)

As of March 1, 2023, the Mineral Resource Development Act in Alberta defined the Alberta Energy Regulator (AER) as the full lifecycle regulator for the province of Alberta's brine-hosted mineral resources. The AER will regulate numerous aspects of the project under several of their regulatory directives as outlined here.

20.1.1.1 AER Directives

- *Directive 090 – Brine Hosted Mineral Resource Development*, is the primary directive that applies to the Boardwalk project. This Directive addresses:
  - The drilling, development, and completion of new wells for the extraction of lithium containing brine.
  - The injection of spent/waste brine that is produced as a by-product following the extraction of lithium from lithium rich brine.
  - Experimental Schemes, such as developing and utilizing past producing oil and gas wells for the extraction of lithium rich brine and disposal of lithium depleted brine.
  - The enhanced recovery of mineral resources such as those that LithiumBank is proposing to utilize in order to extract and produce lithium hydroxide monohydrate (LHM) from brine.
- The collection and disposal of water produced through developing mineral resources.

Additional directives for the AER that are applicable to LithiumBank's Boardwalk project as outlined in Directive 090 include:

- Directive – 001: Requirements for Site-Specific Liability Assessments in Support of the ERCB's Liability Management Programs.
- Directive – 006: Licensee Liability Rating (LLR) Program.
- Directive – 007: Volumetric and Infrastructure Requirements.
- Directive – 013: Suspension Requirements for Wells.
- Directive – 017: Measurement Requirements for Oil and Gas Operations.
- Directive – 020: Well Abandonment.
- Directive – 038: Noise Control.
- Directive – 040: Pressure and Deliverability Testing Oil and Gas Wells.
- Directive – 050: Drilling Waste Management.
- Directive – 051: Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements.
- Directive – 055: Storage Requirements for the Upstream Petroleum Industry.
- Directive – 056: Energy Development Applications and Schedules.
- Directive – 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry.
- Directive – 059: Well Drilling and Completion Data Filing Requirements.
- Directive – 060: Upstream Petroleum Industry Flaring, Incinerating and Venting.
- Directive – 065: Resources Applications for Oil and Gas Reservoirs.
- Directive – 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals.
- Directive – 068: ERCB Security Deposits.
- Directive – 071: Emergency Preparedness and Response.
- Directive – 080: Well Logging.

20.1.1.2 Water Usage, Management and Discharge

All water requirements associated with LithiumBank's proposed Boardwalk project will be permitted, licensed, and regulated by the AER under various acts and regulations such as the *Water Act*, the *Environmental Protection and Enhancement Act* and the *Responsible Energy Development Act*. Aspects of the project which utilize water that will be regulated by the AER or require notification under the Water Act include but are not limited to:

- Fresh water withdrawal and use from water bodies or water courses.
- Installation of pipelines and/or communications lines crossing a water body or water course.
- Discharge of effluent, including stormwater runoff, to waterbodies or water courses.

Permitting for water requirements are to be in place prior to constructing and altering infrastructure that would withdraw water or deposit effluent into a water resource. This would include any water intakes and effluent diffusers, or stormwater infrastructure used for construction, operation, and closure.

20.1.2 Provincial Environmental Impact Assessment (EIA)

Under the AER's Directive 090, item number 23 states that the applicant must apply for Environmental Protection and Enhancement Act (EPEA) approval for a mineral facility designed to process 5000 cubic metres per day or more of water that contains minerals. Included under this item it is also stated that an EIA may be required for the project. Additionally, it is understood that LithiumBank's Boardwalk project will require the development, construction, and operation of an onsite natural gas thermal power plant. The proposed power plant associated with the Boardwalk project is estimated to produce in the magnitude of approximately 166 Mega Watts (MW) of electricity. In Alberta under the Environmental Assessment (Mandatory and Exempted Activities) Regulations and the EPEA, proposed thermal power plants that are designed to produce 100 MW of electricity, or more are required to undergo an EIA. As a result of one or both of these EIA "triggers", a provincial EIA will most likely be required for either the entire project or at least the power plant component of the project.

In Alberta, EIAs typically contain specific information in order to determine an understanding of the project and the potential impacts that it may have on the environment, economy, and society. Assuming that a provincial EIA is to be undertaken for some or all of LithiumBank's Boardwalk project, the following components and information would be required:

- A detailed description of the project outlining its purpose and the reasoning for it.
- The location and the environmental setting of the project.
- Baseline environmental, social, and cultural information.
- The potential positive and negative environmental, health, social, economic, and cultural impacts resulting from the proposed project activities. This includes an assessment of cumulative impacts associated with and resulting from the project activities.
- Mitigation plans for potential adverse effects of project activities as well as emergency response measures.
- Information pertaining to public and First Nations and Indigenous consultation.

It should also be noted that an EIA for LithiumBank's Boardwalk project will be reviewed and administered by the AER as they have been identified as the lifecycle regulator for the project. The process that an EIA for the Boardwalk project would follow would be similar to the one provided in Figure 20.1 most likely undergoing the "Discretionary Activity" pathway as the project appears to be neither a Mandatory nor an Exempt activity.

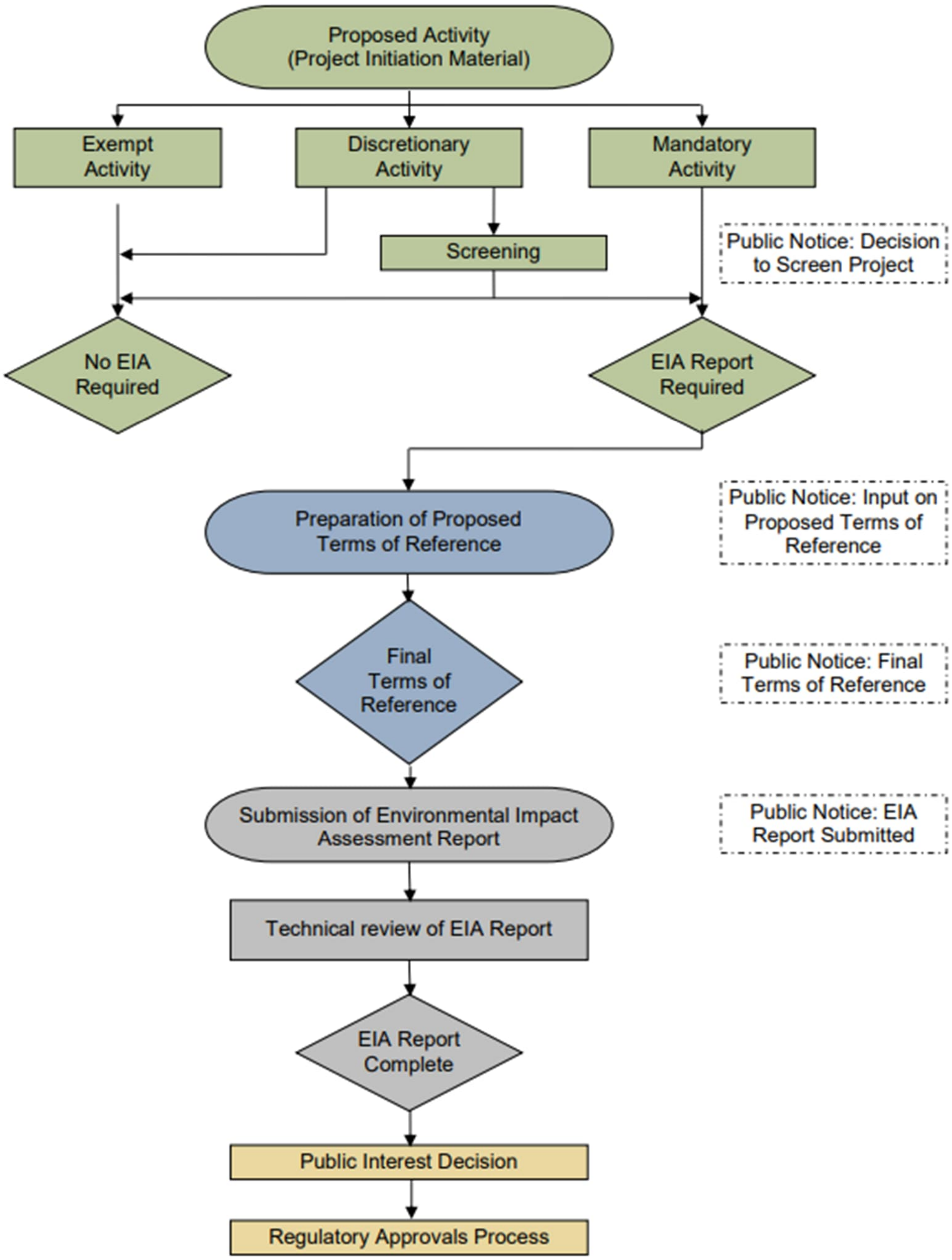


Figure 20.1: Alberta's Environmental Impact Assessment Process (Government of Alberta Operations Division – Provincial Programs)

Once a project has passed through the EIA process it is not considered to be completed and approved until it has undergone the "Public Interest Decision" and "Regulatory Approvals Process" as outlined above in

Figure 20.1. For the Boardwalk project the applicable regulator that would carry out these approvals would be the AER or the Minister of Environment and Protected Areas.

20.1.3 Federal Impact Assessment Agency

Currently, lithium extraction from brine resources or related activities such as those associated with LithiumBank's Boardwalk project are not listed in the federal *Physical Activities Regulations* under the *Impact Assessment Act*. However, the federal Impact Assessment Act (IAA) also provides discretionary authority to the Minister of Environment and Climate Change (the Minister) to designate a proposed project that is not on the Project List under certain conditions, including "… a new or unique type of project that was not contemplated when the Project List was developed." Designation requests may come from any of several sources including other agencies, stakeholders, and/or the project proponent. Contact with the Impact Assessment Agency of Canada, and possibly the submission of an Initial Project Description, would be required to determine if this project would be subject to a discretionary federal Impact Assessment.

20.1.4 Fisheries and Oceans Canada (DFO)

Based on the preliminary design outlined in this PEA it is understood that fresh water will be extracted from the Little Smokey River and utilized in the production of LHM at LithiumBank's Boardwalk facility. This will require a water intake to be constructed in the river which will have impacts on riparian and aquatic habitats during the construction, operation, and removal of the intake. Based on the associated infrastructure and that the Little Smokey River is a fish bearing water course (Government of Alberta Fish and Wildlife Internet Mapping Tool, 2023), it is expected that the project will require:

- Submission of a Request for Review to the DFO, to determine the applicable requirements under the Fisheries Act for the project.
- Application to DFO for an Authorization under Section 35 of the Fisheries Act.

20.1.5 Transport Canada

Under the *Canada Navigable Wasters Act (CNWA)* and the *Minor Works Order Regulations*, administered by Transport Canada, it is required that prior to constructing, placing, altering, rebuilding, removing, or decommissioning a water intake or outfall in a navigable water the following must be completed:

- The owner of the minor work must deposit information describing the proposed activity and the location of the minor works in the registry established under Section 27.2 of the Act.
- Additionally, the owner of the minor work must publish a notice pertaining to the minor works as per the requirements of Transport Canada.

20.1.6 Environmental Permitting and Approval Schedules

A timeline for the environmental permitting and regulatory requirements for the Boardwalk project is dependent on decisions regarding the applicability of certain regulatory requirements by regulators, most notably the provincial EIA and federal IA. These impact assessment processes take extended periods of time to complete, ranging from many months to several years depending on the complexity of the project and associated impacts, and include stakeholder and regulatory input/review periods the introduce uncertainty to the timeframe. Additionally, applications for certain other regulatory approvals and permits required for the project may be dependent on the prior successful completion of the impact assessment process.

20.2 Summary of Environmental Baseline Studies

Environmental baseline studies will need to be conducted to inform the project EIA, and to assist in developing Environmental Design Criteria (EDC) and Environmental Management Plans (EMPs), and to develop project closure and reclamation plans. Provided below are descriptions of several environmental baseline studies likely to be required for LithiumBank's Boardwalk project.

20.2.1 Terrestrial Habitat and Species Surveys

Terrestrial habitat and species surveys would provide an understanding of the habitat's species present within the proposed project site, as well as identify the potential for rare and/or endangered species and their habitats. Field surveys occurring in different seasons and possibly over multiple years would be required.

20.2.2 Aquatic Habitat and Species Surveys

Surveys for aquatic species and habitats would be conducted on potentially impacted surface water resources, such as water courses, wetlands, water bodies and reservoirs. Results of the aquatic habitat and species surveys would also determine the potential presence of rare, endangered, or at-risk species in the affected areas.

20.2.3 Acoustic and Atmospheric Conditions Baseline Assessment

An acoustic and atmospheric conditions baseline assessment would be conducted to provide the following information:

- Background acoustic conditions and pre-existing sources of noise that are anticipated to be present during the life span of the project.
- The identification and separation of anthropological acoustic sources from natural and existing acoustic sources.
- Identification of noise receptors within the project site and project region that will be impacted as a result of the project.
- Current and pre-existing atmospheric conditions including air quality and atmospheric emission generators within the vicinity of the project site and project region.
- Identification of receptors that have a potential to be impacted as a result of any atmospheric releases from the project.

20.2.4 Light Emission Assessment

A light emission baseline assessment would be conducted to provide the following information:

- An assessment of background light emissions within the vicinity of the project.
- Current impacted receptors as a result of existing light emissions within the project region.
- Potential receptors that are anticipated to be impacted resulting from additional light emissions produced by the project.

20.2.5 Water Quality and Available Fresh Water Resource Baseline Data

20.2.5.1 Ground Water

Baseline groundwater studies would be conducted to determine:

- The quality of ground water beneath the proposed project site and its useability.
- The quantity of ground water available for use by LithiumBank as a freshwater resource and its feasibility for use in processes.
- If there are environmental liabilities associated with the past uses of the proposed project area that would require stewardship and continual management of contaminated ground water.

20.2.5.2 Surface Water

A surface water baseline study would be conducted to provide information on the quantity and quality of surface water available for use at the project site, and the feasibility of using surface water resources for on-site operations and processes. In addition, these studies would determine:

- If there any current or pre-existing anthropogenic impacts on the surface water resources within the vicinity of the project and within the project region.
- The upstream and downstream communities, environments, and other commercial and industrial users of identified freshwater resources that may be impacted by the project.

20.3 Potential Environmental Issues and Considerations

The project currently holds contiguous permits for a total of 572,237 acres within the region. Project lands described in this PEA consist primarily of agricultural and forested natural lands which have also been utilized for oil and petroleum hydrocarbon extraction through the installation of oil and gas wells. Additionally, it is understood that the location of the DLE processing facility will be near previous natural gas production facility. Based on the current and historic land use within the proposed project region, a preliminary understanding of environmental considerations related to the project is provided below.

- Management of air emissions produced from the processing of lithium containing brine, onsite power generation and hydrogen sulfide (H_2S) and other fugitive emissions associated with brine extraction.

- Raw water demand requirements for the DLE process and the intake requirements from the Little Smokey River under changing climate conditions and during periods of drought.
- Encounters and potential impacts on rare and endangered species and their associated habitats.
- Management of migratory birds, and other wildlife that may enter the project site and any raw water or storm water storage ponds.
- The safety of public in areas affected by the project activities.
- Preventing and mitigating the impact of releases of substances with the potential to have deleterious impacts on the environment.
- Managing, handling, and preventing surface water runoff that is contaminated with substances that have a potential to cause detrimental impacts on the environment from entering water courses and water bodies.
- Managing for potential flood events should a precipitation event cause excess water to be present within the raw water detention pond.
- Prevent the introduction of fish and other aquatic species from developing and establishing habitat within the raw water storage pond.
- The impacts on aquatic, riparian and terrestrial environments resulting from the development and construction of the project including but limited to water intake and outfall structures on the Little Smokey River, onsite roads, and resurfacing, well pad and building footprints.
- Impacts and of waste management onsite and the temporary onsite storage of waste onsite prior to removal and offsite disposal.
- Emergency planning to handle accidental spills and releases of hazardous wastes and dangerous materials stored on the project site.

20.4 Operational Environmental Management Plans and Monitoring Requirements

20.4.1 Waste and Tailings Disposal Plans

Wastes generated during operations will be managed in a manner that is environmentally acceptable and abides to regulatory requirements. It is expected that most of the waste that will be produced during operations of the Boardwalk project will be spent brine following lithium recovery. Currently, the estimated volume of spent brine generated on a daily basis from the DLE process of the Boardwalk project is approximately 255,404 m^3/d. The spent brine will be disposed of via injection wells into deep underground repositories.

This quantity of spent brine has been identified as being around 1 to 5% greater than the quantity of source brine that is expected to be extracted from producing wells feeding the DLE process. The increased quantity of spent brine requiring disposal as effluent is a result of additional wastewater being generated from sub-processes and incorporated into the spent brine waste stream. LithiumBank will also inject compressed H_2S into the spent brine for co-disposal underground.

Underground disposal of spent brine and other effluents avoids the potential for impacts on the environment at the surface. As the boardwalk project progresses, a complete brine disposal management plan would be developed and implemented to ensure all regulatory requirements administered by the AER for this form of disposal are met.

Other wastes anticipated to be generated in the DLE process include but are not limited to those provided in Table 20-1 below.

Table 20-1: Lithium Extraction Process Waste and Proposed Disposal/ Treatment

Waste Stream Source	State of Matter	Expected Waste Generated	Estimated Quantity[1]	Disposal Location
Pre-treatment Process	Gaseous	Hydrogen Sulfide (H_2S).	Not yet specified[2]	Onsite compression and injection into the waste brine stream for underground disposal.
	Liquid	Hydrocarbons including Light Extractable Petroleum Hydrocarbons (LEPH), Heavy Extractable Petroleum Hydrocarbons (HEPH), Polycyclic Aromatic Hydrocarbons (PAH), and etc.)	Not yet specified[2]	Onsite treatment/ storage prior to transport offsite for refinement and/or management.
	Solid	TSS and TOC Removal Solids	22,270 t/y (dry basis)	Disposal offsite at an approved landfill or treatment facility.
Direct Lithium Extraction (DLE) Process	Liquid	Lithium Depleted Brine (waste brine).	255,404 m^3/d	Offsite disposal in the Leduc aquifers using 50 deep well injection sites.
	Solid	Spent DLE Sorbent	863 m^3 /y	Offsite disposal or recycling at a third-party landfill or treatment facility
	Solid	Gypsum Residue	21,800 t/y (dry basis)	Offsite disposal or recycling at a third-party landfill or treatment facility
Lithium Concentrate Production	Solid	Eluate Reverse Osmosis Cartridge Filter Solids	12 t/y	Offsite disposal or recycling at a third-party landfill or treatment facility
Lithium Hydroxide Monohydrate (LHM) Production	Solid	Sodium Carbonate Filter Solids.	16 t/y	Offsite disposal at a third-party landfill or approved receiving facility.
Utilities	Solid	Raw Water Backwash Filter Solids	105 t/y	Offsite disposal at a third-party landfill or approved receiving facility.
Effluent Treatment	Liquid	Effluent Solution from General Plant	Not yet specified	Offsite disposal or recycling at a third-party landfill or treatment facility

Notes:

1. Estimated quantities included in Table 20-1. Are approximate values based on assumptions and are not considered to be exact at this point in time.
2. Certain values and quantities have not yet been specified during the preparation of this PEA. As such quantities for these identified waste streams were not available to be included in Table 20-1. at the time this report was prepared.

In addition to the wastes generated specific to the DLE process, other wastes that are expected to be generated as part of the Boardwalk project throughout its life cycle are as follows.

- Household and administrative waste generated from office, hygiene, food consumption etc.
- Construction and maintenance waste generated from the any construction and maintenance activities carried out onsite.
- Organic waste generated from land clearing and grubbing activities associated with the preparation and development of any land included in the project.
- Hazardous waste generated from maintenance and or cleanup activities.
- Liquid wastes generated from maintenance and administrative activities taking place onsite.

These waste streams will be managed under a project specific waste management plan to be developed once the Boardwalk project advances to a more detailed stage of development.

20.4.1.1 *Water Management*

The development of water management plans will be required for all stages of the project including site preparation, construction, and operation. During the site preparation stage of the project, a construction water management plan will consider the management of all surface water and runoff encountered or generated onsite. As the project advances into operations, the water management plan will be updated based on the final site configuration and water diversion, control or use at the project site. It is anticipated that during operations, the Boardwalk brine processing and extraction additionally will require a combined total of approximately 200-250 m^3 of raw and potable water every hour to meet the water demands of the plant. Raw water will be required for various uses in the process plant including steam generation, water make up for cooling purposes, rinse water for certain lithium extraction processes, etc. Potable water required for the project will be for administrative and housekeeping purposes such as lavatories, and consumption by humans. The combined raw water and potable water demands do not include the quantity of brine water required for LithiumBank's extraction process.

In an effort to reduce raw water demands, LithiumBank will utilize water recycling processes and techniques in their DLE processes.

20.4.1.2 *Environmental Monitoring Requirements*

Project specific environmental monitoring requirements associated with the Boardwalk project will be determined upon the completion of baseline studies and as a result of the EIA and IA processes as applicable. While the specific monitoring requirements will be determined later in the development of the project, it is expected that monitoring requirements would include project life-cycle monitoring programs of the surrounding terrestrial, aquatic and atmospheric environments, to verify that impacts of the proposed project are within the pre-determined scope of impacts and that no additional detrimental impacts on the environment result. As part of the monitoring of management plans, continual updating, and review of their alignment with regulatory requirements will also be conducted to ensure that applicable regulatory requirements are being met.

20.4.2 Post Closure Requirements

In Alberta under AER Directive 090, the AER requires that every mineral facility develop a closure plan containing specific information to the closure, remediation and reclamation techniques that are to be employed during closure activities. As such, LithiumBank is responsible for developing and ensuring that the following items are completed as part of a closure plan for the Boardwalk project.

- Details of abandonment activities including:
  - Identification of hazardous materials and measures to be taken to control them;
  - Details on the isolation, de-energizing, purging, and cleaning of process and project associated equipment; and,
  - Plans for how all above ground infrastructure and equipment will be dismantled and removed.
- Details of ongoing activities post closure of the facility and project including:
  - Site monitoring.
  - Vegetation control and maintenance.
  - Site security.
- Details of remediation activities, reclamation, and environmental site assessment.
- Timelines that include proposed completion dates for abandonment, environmental site assessment, remediation, and surface land reclamation activities.

The details and precision of a closure and reclamation plan including the above information will evolve over time as the project design evolves. Aspects of the closure requirements that can be estimated at this point in the project design are described in the following sections.

20.4.2.1 Waste and Spent Brine Disposal

The majority of waste that is anticipated to be produced as a result of the project is spent brine which is produced from the lithium extraction process. LithiumBank intends to dispose of their spent brine utilizing deep repository injection wells into the Leduc and Wabamun aquifers beneath the Project site. Additional wastes mentioned in Table 20-1**,** generated over the lifespan of LithiumBank's Boardwalk project are anticipated to be disposed of offsite at third party facilities. As such, any wastes disposed of offsite and accepted at an approved disposal and waste management facility will not require any further management from LihtiumBank post closure of the Boardwalk project.

20.4.2.2 *Water Management*

The development of post-closure water management strategies will be required to mitigate and prevent any environmentally deleterious impacts from occurring on surface water and/ or groundwater at and beneath the former project site. Specifically, water management requirements outlined under the *Environmental Protection and Enhancement Act*, and the *Conservation and Reclamation Regulation (115/1993)* will be applicable to the project stie and will be regulated by the AER. Post closure water management requirements may include, but not be limited to:

- Collecting and treating water that has been impacted from processes associated with LithiumBank's Boardwalk project and ensuring that treated water meets the discharge criteria outlined by the AER prior to discharge into the applicable receiving environment.
- Preventing water from collecting and ponding in areas that have been used for the disposal of waste associated with project processes. Additionally, implementing water diversion structures may be required to divert surface runoff away from potential source of contamination.
- Capping, and sealing all injection and extraction wells in an appropriate manner that is accepted by the AER under Directive 020 – *Well Abandonment* in order to prevent surface water interaction with potentially contaminated ground water and to preserve ground water reserves from surficial impacts.

20.4.2.3 *Environmental Monitoring Requirements*

Environmental monitoring requirements post-closure of the proposed Boardwalk project would be similar to those already conducted for oil and gas operations as outlined by the AER. Environmental monitoring activities are expected to include monitoring and reporting of ground water and surface water conditions for up to 25 years after the issuance of a reclamation certificate as outlined on the AER's *Project Life Cycle* webpage. Additional monitoring requirements may include post-closure terrestrial and aquatic surveys to verify the effectiveness of mitigation measures and remedial programs.

20.5 Remediation and Reclamation

Remediation and reclamation requirements for LithiumBank's Boardwalk project will be regulated and enforced by the AER. During the holistic approval process for brine-hosted mineral projects in Alberta, requirements and conditions for reclamation are developed and provided to the respective project owners and operators. Reclamation conditions and requirements are issued by the AER under the *Environmental Protection and Enhancement Act (EPEA)* and the *Conservation and Reclamation Regulations*. Although the EPEA and *Conservation and Reclamation Regulations* are the primary regulatory documents that enact enforcement for reclamation requirements, there may be additional requirements and conditions outlined by other Acts or Regulations such as the *Public Lands Act* or other relevant regulatory policies. A summary of the current identified requirements for remediation and reclamation are provided in the section below.

20.5.1 *Requirements*

Under the EPEA and the and the *Conservation and Reclamation Regulations* there are several reclamation requirements that need to be fulfilled by LithiumBank related to their proposed Boardwalk project. The AER has expectations surrounding the requirements which LithiumBank is accountable to fulfill or meet as part of their closure, remediation, and reclamation phase of their project. These requirements include:

1. Initiating and completing the clean up of any contamination at the project site and receiving a remediation certificate prior to conducting reclamation activities.
2. Mitigating and reducing land disturbance on and surrounding the project site.
3. Salvaging, storing, and replacing soil on the project site to restore the land to its original land type.
4. Restoring natural drainage features at the project site.
5. Revegetating areas that have been impacted by the project or where soil and vegetation has been disturbed as per reclamation criteria.
6. Any other applicable standards, criteria, guidelines, and directives that are required by the AER as they become established throughout the life of LithiumBank's Boardwalk project.

Following the completion of reclamation activities at the project site and professional sign off, LithiumBank is required to apply for a reclamation certificate through the AER. For leased lands, LithiumBank is also required to submit a paper copy of their entire reclamation certificate application to the landowners and occupants of the reclaimed lands in addition to submitting it to the AER. Upon LithiumBank completing their duty to reclaim project lands and their award of a reclamation certificate, they will be required to conduct environmental monitoring for their previous project lands for up to 25 years. During the 25-year monitoring period, LithiumBank is responsible for conducting any additional remediation activities that may be required if environmental impacts arise from their past uses of the land.

20.5.2 *Estimated Costs of Closure and Reclamation*

Costs required to conduct the closure and reclamation of LithiumBank's Boardwalk project will be associated with the decommissioning of project structures and facilities, and the remediation and restoration of land associated with the project. Estimated costs of reclamation associated with the project site are assumed to be similar to those associated with upstream oil and gas facilities and operations currently existing in Alberta. This assumption is based on the similarities in infrastructure and land use between brine hosted mineral development projects and the upstream oil and gas sector. The primary components of the closure and reclamation cost estimation developed for this PEA are itemized in the CAPEX assumptions and include:

1. Closure of project infrastructure including the demolition and removal of the structures constructed on the site and other project infrastructure.

2. Site wide screening for contamination to soil, groundwater and surface water and conducting remedial activities as warranted by investigations.
3. Activities related to restoring land that was utilized during the lifecycle of the project to pre-project useability.

In addition to the reportable expenses that may be associated with the closure of the Boardwalk Project, the AER notes in Manual 023, *Licensee Life Cycle Management* that additional items are required during the closure, reclamation, and remediation. These items are provided in further detail in Section 21.3.

Closure costs associated with Boardwalk project, based on the current status of the project design, and including closure, remediation and reclamation requirements and activities as summarized above are estimated to be 85.8 M USD, inclusive of a 20% contingency. Further details on the estimated closure costs are provided in Section 21.3.

20.6 Social and Community Impacts

Alberta is known for its long history of oil and gas development, which has sustained many northwestern Alberta local and Indigenous communities financially over the past century. Forward to present date, the industry has gone through many changes due to, among other factors, government commitments to decarbonization and the use of renewable energy resources globally, resulting in a decrease of oil and gas industry activity in Alberta and other Canadian provinces and territories. Due to this shift, resource companies have been finding different applicability for existing technology and infrastructure from the oil and gas industry, finding new solutions to meet sustainability goals and commitments.

LithiumBank is one such company, exploring the use of DLE, to extract lithium from brine using existing oil and gas wells at a proposed development in Sturgeon Lake, Alberta. Lithium extraction as a growing industry is supported the Government of Alberta, which sees potential for the province to become one of the world's largest providers of the resource as a key component for batteries in electric vehicles. To support and regulate lithium extraction, a Minerals Strategy and Action Plan was released, and Bill 82 Mineral Resource Development Act was passed.

Sturgeon Lake is surrounded by small towns and Indigenous communities, including Sturgeon Lake Cree Nation (SLCN) and other First Nation and Métis communities. LithiumBank has reported early engagement with Indigenous communities, including Nations with treaty and traditional territories in the proposed project area. LithiumBank also reports being in the early stages of developing local content plans for Indigenous and local communities in the area of influence, including training, employment opportunities and business development initiatives. Such economic opportunities are expected to be of primary interest to both Indigenous and local communities.

LithiumBank will establish a timeline for the project and create an engagement plan and strategy to support the timeline, with the goal of achieving broad awareness of the project and opportunities for communities to provide feedback, minimizing social risk. Understanding the local communities' concerns and interests and keeping the history of Indigenous and Métis communities at the forefront of project development will assist in reaching agreement on project parameters that are mutually beneficial. The engagement plan will also reflect and satisfy any consultation obligations arising from the provincial and/or federal impact assessment processes, as applicable.

Due to the natural landscape of Sturgeon Lake, recreational areas and trails are highly utilized, and special interest groups such as recreational users, trappers' associations, campground, and outfitting organizations will require engagement. For these groups, awareness of the nature of the project and area of operation will be important, to have a full understanding of any direct impacts to their interests as a result of the project.

Issues of concern to communities will likely be standard concerns regarding traffic, noise, and disruptions, which are expected to be minimal at these planning stages due to low volume of above-groundwork and no drilling or heavy construction. Concerns about water and use and water quality are expected with a project of this kind, with the proponent required to outline measures to ensure integrity of safety processes during brine extraction and to report those measure to community. Bringing attention to the steps LithiumBank plans on taking to address environmental impacts that may result from the project, as well as differentiating the extent of impacts from a lithium extraction project and those of oil and gas industry will be a key objective of any community engagement program.

21. Capital and Operating Cost

The cost estimate for the Project is categorized into initial capital expenditure (CAPEX) and operational expenditure (OPEX). Sustaining capital expenditures over the life of mine (LoM) and closure costs exist in this section separately.

The following are the battery limits to identify the included costs in the project estimate.

- Lithium production wells and gathering brine lines from the resource.
- The reinjection wells and gathering lines to the resource for the lithium depleted brine.
- NOVA Gas Transmission Ltd. (NGTL) tie-in connection to LithiumBank's natural gas supply pipeline which feeds the Combined Cycle Gas Turbine (CCGT) Power Generation Facility.
- Interconnection to the grid to purchase electricity for the most southerly and easterly wellfield operations.
- Raw water supply from the Little Smoky River and groundwater wells.
- Reagents received at the site fence.
- Diesel received by truck into a storage tank located within the plant site.

- Sludge cake residue from the TSS and organic removal process area. Note that the transport and disposal costs for this residue has been accounted for in the OPEX.
- Gypsum residue from lithium extraction. Note that the transport and disposal costs for this residue has been accounted for in the OPEX.
- Treated off gas in accordance with permit discharge criteria, vented to the environment.
- Lithium Hydroxide Monohydrate product in bags, with short term storage on site.

21.1 Initial Capital Cost Estimate

This section presents the capital expenditure (CAPEX) estimate for LithiumBank's Boardwalk Lithium Production Facility and the associated methodologies, assumptions and exclusions that were used to develop the estimate.

The CAPEX has been developed according to a Work Breakdown Structure (WBS) defined by Hatch, as per the table below.

Table 21-1: Project WBS

WBS Number	WBS Name
0000	Plant Wide - General
1000	Onsite Infrastructure
2000	Offsite Infrastructure
3000	Brine Wellfield Services
4000	Surface Brine Infrastructure
5000	Lithium Processing Plant

This CAPEX represents the estimated cost to construct the Boardwalk Lithium Production Facility, including both onsite and offsite infrastructure as well as the brine wellfield services required for the project. The capital cost estimate was prepared for a conceptual level study (AACE Class 5). The target accuracy for this estimate was +50%, -30%. The basis of CAPEX estimate includes data provided by LithiumBank, GLJ, WaterSmart, Go2Lithium, as well as Hatch in-house data to develop the capital cost estimate. Typically, an AACE Class 5 estimate has an accuracy range of -20% to -50% on the low side and +30% to +100% on the high side. +50, -30 falls within this range. The capital costs are expressed in Q3 2023 US Dollars (USD) and do not include allowances for escalation past the base date, currency fluctuation, or interest during construction. For capital costs sourced in Canadian Dollars (CAD), the conversion rate basis used was 1 CAD = 0.73 USD.

21.1.1 CAPEX Summary

The capital cost estimation of the project has four main components: direct costs, indirect costs, contingency and owner's costs.

The estimated cost to complete construction of the LithiumBank Boardwalk project is summarized in the table below.

Table 21-2: Capital Cost Estimate Summary

WBS Level 1	WBS Level 1 Name	Estimated Cost (M USD)
0000	Plant Wide - General	$ 26.7
1000	Onsite Infrastructure	$ 265.2
2000	Offsite Infrastructure	$ 19.5
3000	Brine Wellfield Services	$ 273.0
4000	Surface Brine Infrastructure	$ 207.6
5000	Lithium Processing Plant	$ 610.7
Direct Cost - Subtotal		**$ 1,402.7**
Indirect Cost		$ 327.3
Contingency		$ 373.5
Owner's Cost		$ 56.1
Total Project Capital Cost		**$ 2,159.7**

Note:

(1) Costs provided by GLJ for the Brine Wellfield Services (Area 3000) are a "turnkey" cost including indirects, and contingency. Costs provided by Scott Energy Inc. (contained in Area 1000) for the onsite power generation facility are also a 'turnkey cost', however the contingency for this package was provided and included in the overall contingency (outside the direct costs) at 30% of the total direct and indirect costs of the power plant package.

21.1.2 Direct Costs

Direct costs are the costs of all equipment and materials required for the project, as well as the construction and installation costs for permanent process facilities. This includes:

- Site preparations (bulk earthworks) including the construction of any new in-plant roads and/or storm water ditching and underground services.
- Procurement, assembly, and installation of equipment.
- Procurement, fabrication, and installation of bulk materials.
- Resources for equipment and bulk material installation, such as labour and construction equipment.
- Procurement, fabrication and erection of permanent buildings/structures and associated services.
- Procurement, fabrication, erection of utilities and distribution systems.
- Contractor indirect costs.

- Construction equipment including personal protective equipment (PPE) small tools, consumables, and other equipment (including cranes with capacities of less than 50 tonnes).
- Programming costs.
- Off-site infrastructure.
- Demolition costs (not applicable on this study).

The following table identifies which of the parties involved in the project provided input to the capital cost estimation for each WBS area.

Table 21-3: Key Contributors to WBS Areas

WBS Number	WBS Name	Key Contributor
0000	Plant Wide - General	Hatch
1000	Onsite Infrastructure	Scott Energy Inc.
2000	Offsite Infrastructure	Hatch/WaterSmart/Scott Energy Inc.
3000	Brine Wellfield Services	GLJ
4000	Surface Brine Infrastructure	Hatch
5000	Lithium Processing Plant	Go2Lithium/Hatch

The methodology used to determine the estimate of direct costs for each of the key WBS areas is described below.

21.1.2.1 Plant Wide – General

The size of non-process buildings (such as administrative offices, control room, canteen, laboratory, maintenance building, warehouse, etc.) were estimated based on Hatch in-house data. Unit rates for prefabricated buildings were applied to the various buildings, and cost allowances were made to furnish key infrastructure.

21.1.2.2 Onsite Infrastructure

Scott Energy provided the cost estimate for the onsite thermal power generation facility shown below in Table 21-4. The costs provided by Scott Energy were a ‘turnkey’ cost for the system in Canadian Dollars that were converted to United States Dollars with the foreign currency exchange rate outlined in Section 21.1.

High-voltage and medium-voltage infrastructure, including sub-stations and feeders to Motor Control Centers (MCCs), were estimated by applying a unit rate per kW of electrical infrastructure installed, based on in-house data. The installed electrical demand was tallied from the mechanical equipment list and provisions were made for miscellaneous equipment and non-process buildings.

For details on the onsite thermal power generation facility and infrastructure please refer to Section 18.

The CAPEX relating to onsite infrastructure is shown in the following table.

Table 21-4: CAPEX Summary for Onsite Infrastructure

Cost Component	Estimated Cost (M USD)
Thermal Power Generation Facility	169.9
Electrical Infrastructure and Distribution CPF	28.4
Electrical Infrastructure and Distribution Wellfield	66.9
Total Cost	**265.2**

21.1.2.3 Offsite Infrastructure

WaterSmart provided the cost estimate for the raw water extraction from the Little Smoky River and groundwater wells as well as the water storage infrastructure. Hatch included a provision for the piping and pumping infrastructure associated with supply of raw water from storage to the centralized processing facility. Scott Energy provided the cost estimate for the natural gas supply infrastructure to the onsite power generation facility. The infrastructure details are compiled in Section 18. A summary of the offsite infrastructure direct costs is shown below in Table 21-5.

It should be noted that upgrades to local roads outside the plant fence line are not included, as it is assumed that no upgrades will be necessary given the area is developed. A comprehensive logistics and transportation study, include road infrastructure and accessibility to site should be carried out in subsequent phases of engineering.

Table 21-5: Direct Cost Summary for Offsite Infrastructure

Cost Component	Estimated Cost (M USD)
Raw Water Extraction and Storage	6.6
Raw Water Supply Piping Infrastructure	3.5
Natural Gas Supply Infrastructure	9.4
Total Cost	**19.5**

21.1.2.4 Brine Wellfield Services

The capital cost estimate for the wells was completed by GLJ. Capital cost estimation for the production and injection well network is based on the recommended well network design described in Section 16. The capital costs included herein are estimated to within a +50/-30% range based on the current project stage. This estimate includes a 15% contingency for the well network capital costs, as proposed by GLJ.

The well capital cost comprises all the equipment and services required for the well installation process including transportation, mobilization, demobilization, drilling, logging, cementing, casing, completion, and subsurface pumps. The total cost of each well includes a portion of the civil construction of the well pad and road access, based on the 23 multi-well pads. The capital cost estimation for the well does not include delineation or test wells that may be drilled prior to final design selection.

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

The cost estimation for the injection wells excludes the downhole ESP but otherwise is assumed to be similar to the production wells without a slotted liner set across the injection interval.

Table 21-6:Summary of Well Capital Cost Estimation for Well Network

Well Type	# Wells in Design	Drill, Case and Completion Cost Per Well (CAD)	Subsurface Pump Cost Per Well (CAD)	Total Per Well Cost (CAD)	Total Program Cost (CAD)
Production Well	50	C$ 3,146,994	C$ 900,000	C$ 4,046,994	C$ 202,349,700
Injection Well	50	C$ 3,421,063		C$ 3,421,063	C$ 171,053,150
Total Cost (Direct + Indirect) (CAD)				C$ 373,402,850	
Total Cost (Direct + Indirect) (USD)				$ 272,994,824	

Note: The pumps for production wells are ESPs.

21.1.2.5 Surface Brine Infrastructure

A preliminary pipeline network concept was developed for the project. Hatch determined the approximate quantities for the production and reinjection brine surface pipelines and estimated the cost based on recent vendor quotations.

21.1.2.6 Lithium Processing Plant

Based on the block flow diagrams and mass and energy balance produced during the PEA study, Hatch developed a key mechanical equipment list for each of the sub-areas within this scope. Key mechanical equipment was sized and/or specified (where vendor quotes were obtained). Hatch in-house data was used to cost the supply and installation of most of this equipment, and for some equipment packages vendors were engaged to provide budgetary pricing. In the case of the direct lithium extraction package, a cost estimate was provided by Go2Lithium. Where in-house data was utilized, the cost was adjusted to reflect differences in duty/size/capacity, and inflation rates were utilized to adjust the reference cost to the base date of the estimate.

A factor was applied to the key mechanical equipment cost sub-total, to cater for miscellaneous equipment, not shown on the block flow diagrams, but likely required to facilitate the process.

The total installed mechanical cost was determined for each area, and a direct cost factor was applied to cater for other discipline costs such as site development (earthworks, roads, storm water management), concrete, structural steel and architectural (including buildings), piping, control, and automation, electrical (from MCCs to motors), HVAC and insulation. The direct cost factor was sourced from similar projects. Furthermore, for vendor quoted packaged plants, the direct cost factor was adjusted, dependent on what the vendor included and excluded from their scope of supply.

21.1.3 Indirect Costs

Indirect costs are associated with facilities, materials, services, equipment, and activities required to support the project during the engineering, procurement, construction, and pre-operational testing phases. General items incorporated into the indirect costs include:

- Site indirects, such as indirect labour costs and temporary construction facilities including office trailers, construction cafeteria, sanitation buildings, waste handling structures, temporary warehouses, and temporary construction power infrastructure, etc.
- Materials and equipment that are required to support the construction effort, such as; fuel for construction support equipment, electrical power, communications systems, computer hardware and software, radios, vehicles, safety supplies, temporary warehouse, special heavy equipment for lifting, bottled drinking water, etc.
- Heavy or specialized construction equipment such as cranes with capacities over 50 tonnes.
- Services such as general construction facility maintenance, catering, janitorial, medical treatment, material management, surveying, material quality control services, etc.
- Freight costs associated with the transport of equipment and materials from suppliers' facilities to the project site (including insurance to cover the risk of damaged or lost material during transport to plant site).
- Third party engineering and other services.
- Vendors' representatives to witness installation methods and provide technical advice during pre-operational testing.
- First fills of all materials, consumables or otherwise.
- Start-up/commissioning spares.
- EPCM services which includes detailed engineering design, procurement, and construction management.
- Pre-operational testing services including associated materials.

The indirect costs for the project were estimated by applying factors to the direct costs. The first fill for the DLE sorbent was derived from a quoted price provided by the technology supplier for sorbent replacement and updated to account for the input pricing of the lithium precursor at the time the first fill sorbent is manufactured. The factors used to estimate the indirect cost are from Hatch in-house data and vary for each specific indirect cost item. Note the indirect cost associated with the brine wellfield services and onsite power plant are contained in the package cost provided and included in the direct cost. No additional indirect factors were applied to those specific package costs.

21.1.4 Contingency

Contingency is included in the capital cost estimate as an allowance for normal and expected items of work which must be performed within the defined scope of work covered by the estimate, but which could not be explicitly foreseen or described at the time the estimate was completed. The contingency amount is an integral part of the cost estimate. It does not cover potential scope changes, price escalation, currency fluctuations, allowances for force majeure or other project risk factors or any of the other items that are excluded from the capital cost estimate.

Typical uncertainties applicable to contingency:

- Insufficient information due to incomplete engineering.
- Areas or systems with a reasonable probability of changes occurring during the detail design stage (considered “design development”).
- Equipment or material costs obtained by ratio or update from historical costs or previous estimates.
- Labour productivity and costs.

Typically, a contingency of 30% applied to total directs and indirect costs would be recommended to be applied for a PEA study capital expenditure estimate to be consistent with Hatch guidelines. However, a 25% contingency factor was applied due to the increased definition (including preliminary MTOs) for some process plant areas.

21.1.5 Owner’s Cost

Owner’s costs are included from the LithiumBank Boardwalk Project CAPEX. The owner’s cost for this project was estimated at 4% of total direct costs. Below are items included in owner’s costs:

- Owner’s project team.
- Training of plant operating personnel.
- In-process inventories.
- Treatment of contaminated soil.
- Costs for engineering/test work completed prior to commencing detailed design including any studies.
- Start-up and post start-up commissioning (hot commissioning).

- Permits (other than construction related permits).
- Project all-risk insurance.
- Performance bond premiums.
- Owner's contingency.

21.1.6 Qualifications and Exclusions

21.1.6.1 Qualifications

The following qualifications should be noted for the capital cost estimate:

- The cost estimates reflect the identified scope within the project battery limits.
- None of the pricing for commodities or the design/supply of equipment and services is based on binding quotations or contracts. Budget quotations were obtained from vendors for some major equipment packages.

21.1.6.2 Exclusions

The following exclusions should be noted for the capital cost estimate:

- The cost of local or provincial road/highway modifications to accommodate the project is not included. This includes any temporary or long-term upgrades that may be necessary to deliver equipment or goods to site during the plant construction.
- Provision for residue/waste storage and/or management facilities has not been made. It is assumed that all residues/wastes will be transported from the plant for further processing by third parties. For residues which will be sold for third party processing, it is assumed the third party will collect the residue at the plant site.
- Escalation of equipment, material, and labour costs beyond the estimate base date.
- Variations in currency exchange rates from those used by vendors to develop quotations.
- All taxes and duties, except for those included in construction labor rates.
- Costs due to labour relations and labour stoppages.
- Force majeure.
- Cost of environment and ecology related items.
- Financing costs.
- Costs for future/planned test work, piloting and/or studies was not allowed for in the above indirect cost estimate. Provision for future test work, pilot plant and studies should be made in the owner's costs.
- Land purchase cost is not included in the estimate as the land is already leased.
- Costs associated with lost time due abnormal weather events.

- Costs associated with significative schedule delays.
- Start-up and ramp-up commissioning stages.
- The right of passage for the pipelines.

21.2 Sustaining Capital Cost

Sustaining capital expenditure encompasses the replacement of major equipment that is not serviceable with normal maintenance.

The ESPs recommended for the production wells are estimated to have a pump life of five 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. The percentage of failures in the first five years of operation will be less than the average failure rate over the project life but it is difficult to estimate since it is dependent on the operational conditions and ongoing improvements to ESP components. The cost for each pump replacement is assumed to be CAD 700,000 per ESP including rig time. The initial cost of CAD 900,000 per pump includes surface equipment (VFD) associated with electrical delivery to pump and instrumentation but this should not need to be replaced when the ESP is changed. An estimate of annual ESP replacement costs as sustaining capital is CAD 5,000,000/yr (equivalent to 3.7 M USD/year), which takes into consideration an average failure rate over a five-year period. This may be less in the first years of operation and more as the project matures.

Membrane, anode, and cathode replacement have been included in the consumables cost component of the operating costs in Section 21.4.5.

The sustaining capital expenditure for the overall lithium processing plant is estimated at an annual basis of 0.3% of the direct cost of the lithium processing plant to be 2.9 M USD/year, which is equivalent to 84 USD/t LHM. The total estimated sustaining capital cost for the overall project is 6.5 M USD/year.

21.3 Closure and Reclamation Costs

Costs required to conduct the closure and reclamation of LithiumBank's Boardwalk project will be associated with the decommissioning of project structures and facilities, and the remediation and restoration of land associated with the project. Estimated costs of reclamation associated with the project site are assumed to be similar to those associated with upstream oil and gas facilities and operations currently existing in Alberta. This assumption is based on the similarities in infrastructure and land use between brine hosted mineral development projects and the upstream oil and gas sector.

Closure of the project infrastructure includes the demolition and removal of the following:

- Auxiliary facilities outlined in Section 18.3.1.
- Well pad access roads.
- Well field electrical infrastructure.

- Production and injection wells and well pads.
- Piping and pumping infrastructure for production and injection brine.
- Piping and pumping infrastructure for raw water system.
- Lithium processing plant buildings.
- Thermal power generation plant.

Site wide screening for contamination and conducting remedial activities including:

- Conducting a site wide Phase I Environmental Site Assessment (Phase I ESA).
- Conducting Phase II Environmental Site Assessments (Phase II ESAs) where warranted by the results of the Phase I ESAs.
- Completing remedial activities when warranted by the results of the Phase II ESAs.

Activities related to restoring land associated with the project to pre-project useability including:

- Earth works to restore natural topography.
- Natural drainage restoration.
- Topsoil replacement.
- Vegetation replacement and planting.
- Replacement of natural riprap material.
- Revegetation along impacted water courses and riverbanks.
- Removal of culverts utilized for access roads.
- Restoration of stream bed conditions in the little smokey river.
- Site wide monitoring and maintenance requirements.

In addition to the reportable expenses that may be associated with the closure of the Boardwalk Project outlined in Manual 023, *Licensee Life Cycle Management*, the AER notes that the following are also to be completed and are required as part of remediation, reclamation and closure activities for brine hosted mineral projects.

- For land that is leased, it will be required that LithiumBank remediate any environmental contamination they are responsible for producing and reclaim the land to a pre-project quality.
- A $1,000 payment is required as part of the application for a reclamation certificate.
- A security deposit, which is required to be paid in full as requested by the AER, will be required during the licensing phase of the Boardwalk project. The amount associated with

the security deposit is based on the assessed liability associated with the project and may range from 50% to 100% of the assumed liability costs as per the AER.

Closure costs associated with the Boardwalk project, based on the current status of the project design, and including closure, remediation and reclamation requirements and activities as defined above, are estimated to be 85.8 M USD which is inclusive of a 20% contingency.

21.4 Operating Cost Estimate

21.4.1 Basis of Operating Cost

The basis used to assess the operating cost of the project is defined as follows:

- The currency basis for the operating cost estimate is United States Dollars (USD). Some costs for the estimate were sourced in Canadian Dollars (CAD). The conversion rate basis used was 1 CAD = 0.73 USD.
- The lithium processing plant has an operating factor of 90%, or 7,884 operating hours per year.
- Operating costs are based on an average full year of production and are not reflective of construction, start-up, and ramp-up commissioning phases of the project.
- Production unit costs presented in this section are based on cost in USD per metric tonne of lithium hydroxide monohydrate produced.
- Operating costs are based on 34,252 tpa LHM production, 217 tpa lithium carbonate from the bleed process (246 tpa LHM eqv.) would be provided to Go2Lithium under a tolling-type agreement to produce the sorbent for lithium extraction. As a result, the annual net sales volume is 34,005 tpa LHM.
- A contingency of 10-15% is typically applied to operating cost estimates at this level of development as it is not possible to precisely define or quantify all the costs which will be expended for the project. Note, no contingency is included in the current estimate.

21.4.2 Operating Cost Summary

The estimated operating costs for LithiumBank's Boardwalk Lithium Production Facility is summarized below in Table 21-7. The project's operating costs are grouped into eight major cost categories. Reagents, Utilities, Consumables, Labour, Maintenance Materials and Well Servicing, Transport and Logistics, and General and Administrative Expenses.

The total estimated operating cost is USD 155.2 M, or USD 4,533 per metric tonne LHM. The reagents and utilities account for 24% and 33% of the total operating costs respectively for this project.

Table 21-7: Operating Cost Summary

Cost Component	Lithium Plant Annual Operating Cost (M USD)	Lithium Plant Unit Operating Cost (USD/t LHM)	% of total OPEX
Reagents	37.3	1,089	24%
Utilities	51.9	1,515	33%
Consumables	16.5	482	11%
Labour	17.6	513	11%
Maintenance Materials and Services	18.7	546	12%
Transport and Logistics	6.6	192	4%
General and Administrative (G&A)	6.7	196	4%
Total Operating Cost	**155.2**	**4,533**	**100%**

21.4.3 Reagents

One of the largest contributors to the operating cost for the project is the costs associated with reagent addition. Reagent costs were calculated based on the operating consumption rates which were determined in the mass and energy balance. The unit cost of reagents such as sulfuric acid, lime and sodium carbonate were confirmed with a distributor in the Edmonton, Alberta region. The cost of sodium hydroxide was determined by a forecast study conducted by ResourceWise (ResourceWise, 2023). The cost of the DLE replacement extraction sorbent was provided by the DLE technology supplier, Go2Lithium. Note the price of sorbent replacement assumes that 246 tpa LHM eqv. (~0.7% of total LHM production) is supplied to the sorbent manufacturer and converted to sorbent. The total operating cost of reagents for the project is estimated to be USD 37.3 M, which equates to USD 1,089 per metric tonne of LHM. The cost of the reagents and chemicals used in the process are summarized in Table 21-8.

Table 21-8: Reagent Operating Costs

Reagents	Annual Cost (M USD)	Unit Cost (USD/t LHM)
Sulfuric Acid (98 wt.%)	4.3	125
Sodium Hydroxide (50 wt.%)	0.001	0.03
Lime	13.6	396
Sodium Carbonate	8.2	240
DLE Replacement Sorbent	9.1	265
Other Reagents	2.2	63
Total Cost	37.3	1,089

21.4.4 Utilities

21.4.4.1 Power

The power consumption for the process is summarized in Table 21-9 and sub-divided into three key areas: the brine production wells, brine reinjection and the lithium processing plant. The majority of the power required for the project will be provided by a combined cycle gas turbine (CCGT) power generation facility owned and operated by LithiumBank. Power generated at this facility will supply electricity to the site at a cost of USD 36.0/MWh, which includes the cost of natural gas supplied, fixed costs and other consumables. The remaining power required for the project will be supplied by the grid, at a cost of USD 98.7/MWh. Steam will be supplied by the LithiumBank power plant to the processing facilities, free issue. The total annual operating power consumption of the plant is estimated to be 1,041,112 MWh, resulting in an annual cost of approximately USD 50.4 M or USD 1,471 per metric tonne LHM (see Table 21-9).

Table 21-9: Power Operating Costs

Process Area	Annual Power Consumption from CCGT Facility (MWh)	Annual Power Consumption from Grid (MWh)	Total Annual Power Consumption (MWh)	Annual Cost (M USD)	Unit Cost (USD/ t LHM)
Brine Production Wells	213,459	142,306	355,766	21.7	634
Brine Reinjection Wells	254,859	63,715	318,574	15.5	451
Lithium Processing Plant	366,773	-	366,773	13.2	385
Total	835,091	206,021	1,041,112	50.4	1,471

21.4.4.2 Natural Gas

Natural gas delivered from NGTL is assumed to be CAD 5.00/GJ (equivalent to USD 3.70/GJ). This assumes that the NGTL receipt and delivery charges have been paid for by the party contracted to supply the natural gas for the facility. The natural gas is only used in the power generation facility and the cost of that supply is already incorporated in the power operating cost.

21.4.4.3 Water

Raw water will be supplied from the Little Smoky River and a groundwater well source to meet the water requirements for the project. The operating costs associated with the raw water supply and treatment are included in the reagents, power, and other cost centers of the operating cost.

21.4.5 Consumables

The operating costs were determined based on requirements from the mass and energy balance and equipment sizing calculations. The key process consumables include:

- Product packaging.

- Filter cloth replacement.
- Filtration media.
- Water treatment consumables.
- Electrochemical process consumables.
- Laboratory supplies.

The operating costs associated with the process consumables are estimated to be USD 16.5 M, which equates to USD 482 per metric tonne LHM.

21.4.6 Labour

In order to assess the operating costs associated with labour for the plant, typical salaries from The Association of Professional Engineers and Geoscientists of Alberta (APEGA) were used to determine estimated salaries and wages for various personnel types. These salaries can be found in Table 21-10.

Table 21-10: Base Salaries for Labour

Position Tier	Base Salary (CAD)	Base Salary (USD)
High Tier	175,000	129,500
Mid-Tier 1	137,500	101,750
Mid-Tier 2	112,500	83,250
Mid-Tier 3	92,500	68,450
Low Tier 1	92,500	68,450
Low Tier 2	75,000	55,500
Low Tier 3	50,000	37,000

Additional factors were considered on top of the base salaries, including 42% additional compensation and an annual average overtime factor of 43%. The overtime factor accounts for the additional compensation that will be paid for working over 40 hours per week, as well as working on weekends and holidays. There are also allowances for holidays, vacation time, sick leave, and training. It is also noted that operating staff will be required 8,760 hours per year, which includes both operating and non-operating time. The staffing plan and total labour costs are shown in Table 21-11. The labour costs for the project are estimated to be USD 17.6 M, which equates to USD 513 per metric tonne of LHM.

Table 21-11: Staffing Plan and Labour Cost Summary

Staff	Total Workers	Labour Cost (M USD)	Unit Labour Cost (USD/t LHM)
Admin, Management and Support Staff	17	2.2	63
Plant Operators	71	7.7	224

Staff	Total Workers	Labour Cost (M USD)	Unit Labour Cost (USD/t LHM)
Maintenance Staff	39	4.5	131
Technical Services Staff	26	3.2	94
Total	153	17.6	513

21.4.7 Maintenance Materials and Services

21.4.7.1 Production well network

Operating cost estimation has been conducted for the well network plan at full capacity of 250,000 m^3/d brine production flow rate and lithium depleted brine injection stream of 255,404 m^3/d. It is expected that during ramp-up in the first 1-3 years, the operating costs will be higher. The operation of the lithium brine production and injection wells are similar to oil wells, which serve as the basis for variable and fixed operating cost parameters. Fixed costs include surface pad and road maintenance, well non-capital maintenance, fluid sampling/analysis, waste management, road use fees, security, and field operations staff. The variable operating costs are related to brine production and typically include fuel and electricity costs for pump operation and chemicals, metering/instrumentation, and related trucking costs. Chemicals will be required for corrosion inhibition and scale prevention.

The production of sour components as a gas or within the brine fluid, such as hydrogen sulfide (H_2S) or carbon dioxide (CO_2), are anticipated to be in quantities that require special operational considerations for safety and corrosion protection. The operating costs include a small consideration for sour fluid and gas handling, but these would be refined when flow tests are conducted, and gas and fluid compositions are evaluated in the project target area.

Well servicing (workovers) may be required for the production and injection wells. Impairments to productivity or injectivity are typically due to blockages in the aquifer near the wellbore, sometimes referred to as skin factor. The blockages can be a result of scale buildup from geochemical reactions or incompatible fluid chemistry, or buildup of fine particles or precipitates that cause flow impairment. These types of impairments can usually 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. An annual cost of 2.5 M/yr is estimated, as included in the fixed well operating cost to account for these types of workovers and well treatments.

The summary of well operating costs split by fixed and variable are shown below in Table 21-12. Note that the operating costs shown are for a total annual brine flow of 91,250,000 m^3. Many factors can influence the operating costs such as supply chain contracts, power pricing, logistics of operations staff and central operating facilities, and other considerations. The estimate conducted for this report is at a high level and will require refining as the project operating plan is developed.

Table 21-12: Summary of Well Operating Cost Estimation

Well Operating Cost Type	Unit Cost (CAD)	# Wells	Total Annual (CAD)	Total Annual (USD)
Well Fixed	4,892/Well-Month	100	5,870,000	4,290,000
Variable Water	0.06/m^3		5,046,178	3,689,261
Total Annual Well Operating Expense (excluding power)			10,916,178	7,979,261
Total Well $/$m^3$ Produced Brine (excluding power)			0.12	0.09

The operating cost related to power requirements for the production wells for ESP operation are not included in the well operating cost estimate but rather included in the overall power costs (see Table 21-9).

21.4.7.2 *Lithium Processing Plant*

Maintenance costs for the lithium processing plant were calculated to account for normal equipment repair and replacement. Hatch in-house data was used to determine appropriate factors and maintenance costs for each process section of the plant. The cost of labour associated with this maintenance is included in Section 21.4.6. The maintenance materials costs for the lithium processing plant (excluding labour) are estimated to be USD 10.7 M or USD 313 per metric tonne LHM.

Therefore, the total maintenance materials costs of the project including the well operation and the lithium processing plant is estimated to be USD 18.7 M or USD 546 per metric tonne LHM.

21.4.8 Transport and Logistics

It is estimated that the lithium processing facility will generate 44,530 t/y wet of TSS/TOC removal residues and 36,430 t/y of mainly wet gypsum.

The TSS/TOC removal residue will be collected and disposed of offsite. The cost of transport and disposal costs for this residue has been estimated at USD 75/t and is included in the operating cost estimate.

Work is underway to identify potential third parties who may be able to use the gypsum. For the purposes of this study, it is assumed that the gypsum residue will also be collected and disposed of offsite. Therefore, the USD 75/t cost of transport and disposal is also considered for this residue.

Product transport is not included in the OPEX but has been included in the economic analysis section, see Section 22. The estimated product transportation cost to potential future customers in the American Midwest is CAD 2,500 per 26.3 tonne, equivalent to CAD 95 per metric tonne LHM or USD 70 per metric tonne LHM.

21.4.9 General and Administrative Expenses (G&A)

General and administration expenses are the costs not directly attributed to specific plant or process areas but are required for the operation as a whole. These include computing costs, business travel, office supplies, staffing training, medical services, first aid, personal protective equipment, insurance, and marketing personnel. Contract services include engineering, environmental, legal, or other consultant services as well as onsite support services.

The G&A cost summary is listed in Table 21-13.

Table 21-13: General and Administrative Expense (G&A) Cost Summary

G&A Cost Components	Annual Cost (M USD)	Unit Cost (USD/t LHM)
General Corporate Services	3.6	104
Contract Services	3.2	92
Total	6.7	196

21.4.10 Exclusions

The operating cost estimate excludes the following:

- Forward escalation of operating cost inputs.
- Extraordinary events.
- Cost of any disruption to normal operations.
- Taxes; including Carbon Tax.
- Contingency has been excluded (see note in Section 21.4.1).

22. Economic Analysis

22.1 Introduction

The PEA is preliminary in nature. It includes inferred mineral resources that are too speculative geologically to have 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.

The economic analysis is based on a discounted cash flow model in real terms. The model includes the 20-year life-of-project production plan for lithium hydroxide monohydrate (LHM), operating costs, capital costs, and market assumptions discussed in this report, in addition to financial assumptions introduced in this section. Project returns are calculated in the model before and after taxes, including net present value (NPV), internal rate of return (IRR), and payback period.

Returns are sensitive to input assumptions and should be viewed in the context of the sensitivity analysis provided in this section as well as the stated accuracies for items such as capital costs.

The base case assumes a long term LHM price of USD 26,000/t. At this price the project achieves a positive NPV at an 8% real discount rate. A summary of key indicators is shown in Table 22-1.

The reader is cautioned that the 98% lithium recovery used in this analysis has not yet been proven at commercial scale (see Section 25.6.4 Recovery Methods Risks). As such, the sensitivity around recovery is particularly important. In general, each 1% absolute drop in recovery decreases modeled pre-tax and after-tax NPV by US$62M and US$42M, respectively, and decreases pre-tax and after-tax IRR by 0.24% and 0.20%, respectively.

Table 22-1: Key Indicators Summary

Item	Unit	Value
LHM Sales	t/year	34,005
LHM Price	US$/t	26,000
Site Operating Unit Cost	US$/t sold	4,588
Site Operating Cost	US$M/year	154
EBITDA	US$M/year	715
Project Life	years	20
Initial Capital Cost	US$M	2,160
Sustaining Capital Cost	US$M	131
USD/CAD Exchange Rate	US$/C$	0.73
Pre-tax NPV @ 8%	US$M	3,679
After-tax NPV @ 8%	US$M	2,305
Pre-tax IRR	%	25.0%
After-tax IRR	%	20.6%
Pre-tax Payback	operating years	3.5
After-tax Payback	operating years	3.9

22.2 Assumptions and Inputs

22.2.1 General

The following general assumptions form part of this analysis:

- Currency basis is real 2023 USD with no inflation.
- 100% equity financing.
- 0.73 US$/C$ exchange rate.
- Mid-year discounting for NPV calculation.

22.2.2 Production and Sales Schedule

Section 17 indicates the annual production volume is 34,252, tpa LHM and Section 21 indicates that 246 tpa LHM eq. would be provided to Go2Lithium under a tolling-type agreement to produce the sorbent for lithium extraction. As a result, a net sales volume of 34,005 tpa LHM is applied in the model.

The model considers a 20-year production schedule with 70% of steady-state annual production in the first year to account for process ramp up.

22.2.3 Product Pricing

A constant long-term price of US$26,000/t LHM from Section 19 is applied.

22.2.4 Transportation Costs

The product transportation cost of C$95/t from Section 21 is applied.

22.2.5 Site Operating Costs

Site operating costs of USD 155.2M per year from Section 21 are applied, with an adjustment for variable and fixed costs during the first year of production due to ramp-up.

22.2.6 Working Capital

Working capital is based on 60 days of accounts receivable, 60 days of accounts payable, and 30 days of inventory. Working capital is reflected in the cash flow as changes in net working capital.

22.2.7 Capital Costs

The USD 2,159.7M initial capital cost estimate and USD 6.5M/year sustaining capital cost estimate from Section 21 are applied. Initial capital costs are spread over a three-year construction period. Closure costs of USD 85.8M from Section 21 are applied during a one-year period following production Year 20.

22.2.8 Government Royalties and Taxes

Preliminary and simplified tax calculations are appropriate at the PEA stage. The model applies the Alberta Metallic and Industrial Minerals Royalty, Canadian federal corporate taxes, and Alberta provincial corporate taxes. The analysis did not consider the company's existing tax pools.

The Alberta Metallic and Industrial Minerals Royalty applicable to this project is 1% of gross mine-mouth revenue before payout and the greater of 1% gross mine-mouth revenue or 12% net revenue after payout. These terms are defined in Alberta Regulation 350/1993.

Federal and provincial corporate taxes are based on a 15% federal and 8% provincial tax rate and are payable on taxable income. Capital cost allowance (CCA) Class 41 depreciation at 25% is applied and tax losses are carried forward.

22.3 Cash Flow

The annual cash flow summary for the PEA base case is shown in Table 22-2 along with key economic indicators.

Table 22-2: Annual Cash Flow Summary

Item	Units	Total	-3	-2	-1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
LHM Sales	t LHM	669,901	-	-	-	23,804	34,005	34,005	34,005	34,005	34,005	34,005	34,005	34,005	34,005	34,005	34,005	34,005	34,005	34,005	34,005	34,005	34,005	34,005	34,005	-
LHM Price	US$/t LHM	26,000	-	-	-	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	-
Gross Revenue	**US$M**	**17,417**	**-**	**-**	**-**	**618.9**	**884.1**	**884.1**	**884.1**	**884.1**	**884.1**	**884.1**	**884.1**	**884.1**	**884.1**	**884.1**	**884.1**	**884.1**	**884.1**	**884.1**	**884.1**	**884.1**	**884.1**	**884.1**	**884.1**	**-**
Product Transportation	US$M	(46)	-	-	-	(1.7)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	-
Site Operating Costs	US$M	(3,073)	-	-	-	(123.5)	(155.2)	(155.2)	(155.2)	(155.2)	(155.2)	(155.2)	(155.2)	(155.2)	(155.2)	(155.2)	(155.2)	(155.2)	(155.2)	(155.2)	(155.2)	(155.2)	(155.2)	(155.2)	(155.2)	-
Reagents	US$M	(734)	-	-	-	(26.1)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	(37.3)	-
Utilities	US$M	(1,022)	-	-	-	(36.3)	(51.9)	(51.9)	(51.9)	(51.9)	(51.9)	(51.9)	(51.9)	(51.9)	(51.9)	(51.9)	(51.9)	(51.9)	(51.9)	(51.9)	(51.9)	(51.9)	(51.9)	(51.9)	(51.9)	-
Consumables	US$M	(326)	-	-	-	(11.6)	(16.5)	(16.5)	(16.5)	(16.5)	(16.5)	(16.5)	(16.5)	(16.5)	(16.5)	(16.5)	(16.5)	(16.5)	(16.5)	(16.5)	(16.5)	(16.5)	(16.5)	(16.5)	(16.5)	-
Labour	US$M	(351)	-	-	-	(17.6)	(17.6)	(17.6)	(17.6)	(17.6)	(17.6)	(17.6)	(17.6)	(17.6)	(17.6)	(17.6)	(17.6)	(17.6)	(17.6)	(17.6)	(17.6)	(17.6)	(17.6)	(17.6)	(17.6)	-
Maintenance Materials	US$M	(374)	-	-	-	(18.7)	(18.7)	(18.7)	(18.7)	(18.7)	(18.7)	(18.7)	(18.7)	(18.7)	(18.7)	(18.7)	(18.7)	(18.7)	(18.7)	(18.7)	(18.7)	(18.7)	(18.7)	(18.7)	(18.7)	-
Transport and Logistics	US$M	(131)	-	-	-	(6.6)	(6.6)	(6.6)	(6.6)	(6.6)	(6.6)	(6.6)	(6.6)	(6.6)	(6.6)	(6.6)	(6.6)	(6.6)	(6.6)	(6.6)	(6.6)	(6.6)	(6.6)	(6.6)	(6.6)	-
G&A	US$M	(134)	-	-	-	(6.7)	(6.7)	(6.7)	(6.7)	(6.7)	(6.7)	(6.7)	(6.7)	(6.7)	(6.7)	(6.7)	(6.7)	(6.7)	(6.7)	(6.7)	(6.7)	(6.7)	(6.7)	(6.7)	(6.7)	-
EBITDA	**US$M**	**14,298**	**-**	**-**	**-**	**493.7**	**726.5**	**726.5**	**726.5**	**726.5**	**726.5**	**726.5**	**726.5**	**726.5**	**726.5**	**726.5**	**726.5**	**726.5**	**726.5**	**726.5**	**726.5**	**726.5**	**726.5**	**726.5**	**726.5**	**-**
Changes in Net Working Capital	US$M	-	-	-	-	(91.6)	(41.0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	132.6
Initial Capital Cost	US$M	(2,160)	(323.9)	(863.9)	(971.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sustaining Capital Cost	US$M	(131)	-	-	-	(6.5)	(6.5)	(6.5)	(6.5)	(6.5)	(6.5)	(6.5)	(6.5)	(6.5)	(6.5)	(6.5)	(6.5)	(6.5)	(6.5)	(6.5)	(6.5)	(6.5)	(6.5)	(6.5)	(6.5)	-
Closure Cost	US$M	(86)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(85.8)
Pre-Tax Cash Flow	**US$M**	**11,922**	**(323.9)**	**(863.9)**	**(971.8)**	**395.6**	**679.0**	**720.0**	**720.0**	**720.0**	**720.0**	**720.0**	**720.0**	**720.0**	**720.0**	**720.0**	**720.0**	**720.0**	**720.0**	**720.0**	**720.0**	**720.0**	**720.0**	**720.0**	**720.0**	**46.8**
Alberta Royalty	US$M	(1,453)	-	-	-	(6.2)	(8.8)	(8.8)	(47.1)	(86.4)	(86.4)	(86.4)	(86.4)	(86.4)	(86.4)	(86.4)	(86.4)	(86.4)	(86.4)	(86.4)	(86.4)	(86.4)	(86.4)	(86.4)	(86.4)	-
Federal and Provincial Tax	US$M	(2,434)	-	-	-	-	-	(97.1)	(117.1)	(117.5)	(124.5)	(129.8)	(133.8)	(136.8)	(139.0)	(140.7)	(142.0)	(142.9)	(143.6)	(144.1)	(144.5)	(144.8)	(145.1)	(145.2)	(145.3)	-
After-Tax Cash Flow	**US$M**	**8,034**	**(323.9)**	**(863.9)**	**(971.8)**	**389.4**	**670.2**	**614.1**	**555.8**	**516.1**	**509.1**	**503.8**	**499.8**	**496.8**	**494.6**	**492.9**	**491.6**	**490.7**	**490.0**	**489.5**	**489.1**	**488.8**	**488.5**	**488.4**	**488.2**	**46.8**
Project Economics																										
Pre-tax NPV @ 8%	US$M	3,679																								
After-tax NPV @ 8%	US$M	2,305																								
Pre-tax IRR	%	25.0%																								
After-tax IRR	%	20.6%																								
Pre-tax payback	op. years	3.5																								
After-tax payback	op. years	3.9																								

22.4 Cash Flow Summary

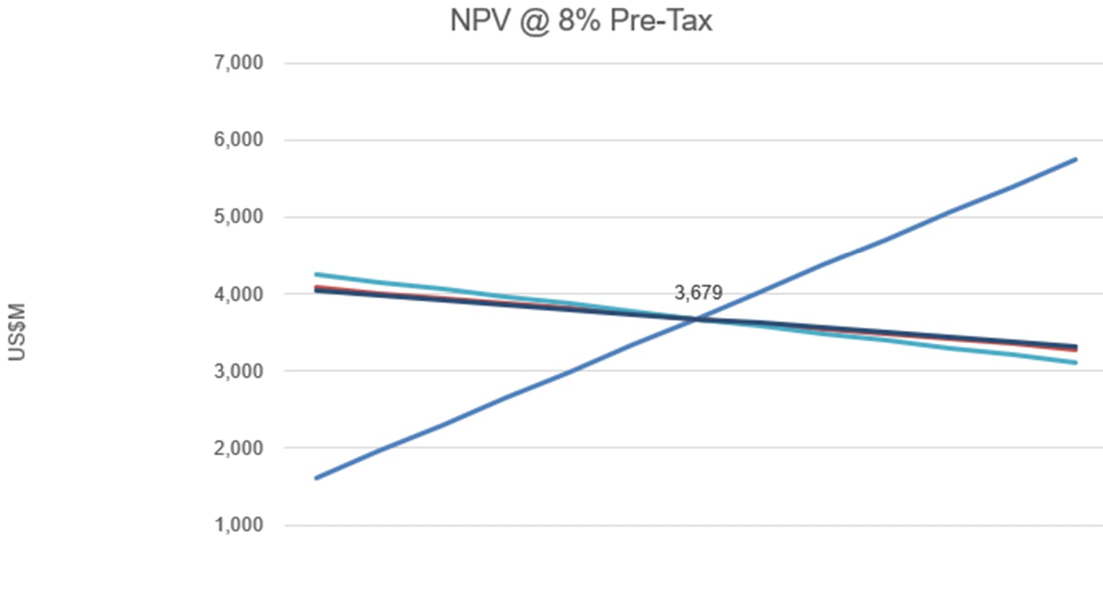
Table 22-3 summarises the life-of-project cash flow discounted and undiscounted, annual average cash flow, and cash flow on a unit basis in US$/t LHM terms.

Table 22-3: Cash Flow Summary for Life of Project

Item	Undiscounted			Discounted
	Annual Average (US$M/year)	Unit Average (US$M/t LHM sold)	Total (US$M)	Total (US$M)
Gross Revenue	**871**	**26,000**	**17,417**	**6,959**
Product Transportation	(2)	(69)	(46)	(19)
Site Operating Costs	(154)	(4,588)	(3,073)	(1,233)
EBITDA	**715**	**21,343**	**14,298**	**5,707**
Changes in Net Working Capital	-	-	-	(77)
Initial Capital Cost	(108)	(3,224)	(2,160)	(1,883)
Sustaining Capital Cost	(7)	(195)	(131)	(53)
Closure Cost	(4)	(128)	(86)	(14)
Pre-Tax Cash Flow	**596**	**17,796**	**11,922**	**3,679**
Alberta Royalty	(73)	(2,169)	(1,453)	(509)
Federal and Provincial Tax	(122)	(3,633)	(2,434)	(865)
After-Tax Cash Flow	**402**	**11,993**	**8,034**	**2,305**

22.5 Sensitivity Analysis

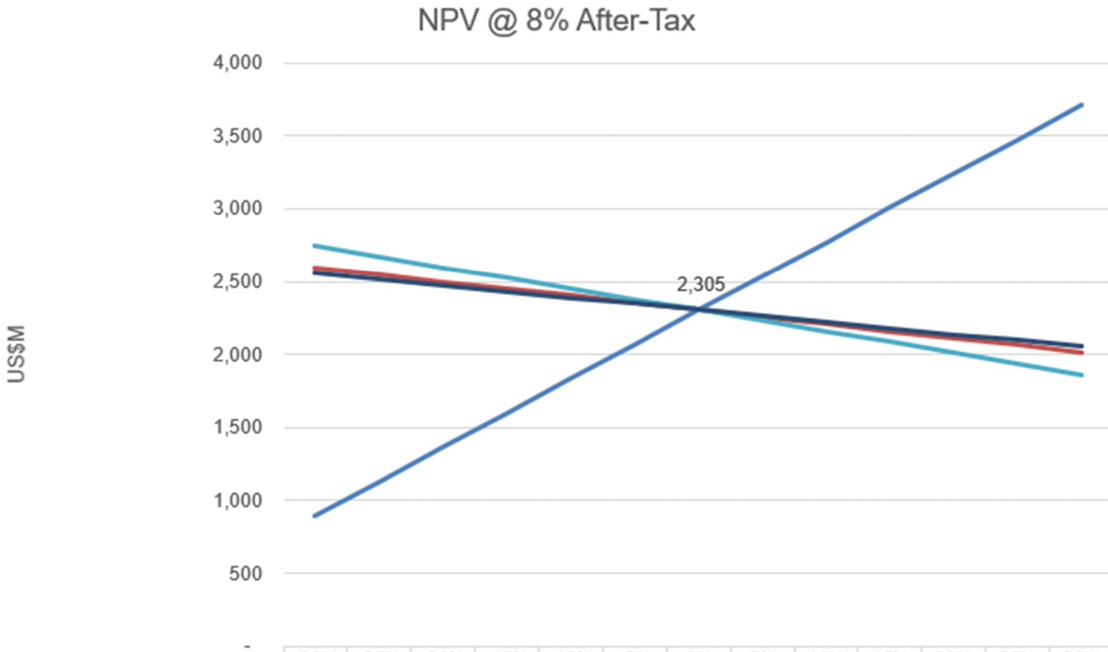
A sensitivity analysis was used to test the impact of key financial variables on project returns for the given production schedule. The product price, exchange rate, capital cost, and operating cost were each varied independently on an annual basis and the resulting variations in NPV @ 8% and IRR are shown in Figure 22.1 through Figure 22.4 before and after taxes. NPV is most sensitive to product price. Initial capital cost, operating cost, and exchange rate have a smaller impact on NPV. For clarity, variations in the exchange rate impact capital and operating costs originating in Canadian dollars, such as labour.



	-30%	-25%	-20%	-15%	-10%	-5%	0%	5%	10%	15%	20%	25%	30%
LHM Price	1,617	1,961	2,305	2,648	2,992	3,336	3,679	4,023	4,367	4,711	5,054	5,398	5,742
USD/CAD exchange rate	4,075	4,009	3,943	3,877	3,811	3,745	3,679	3,613	3,548	3,482	3,416	3,350	3,284
Initial Capital Cost	4,244	4,150	4,056	3,962	3,868	3,774	3,679	3,585	3,491	3,397	3,303	3,209	3,114
Operating Cost	4,047	3,986	3,925	3,863	3,802	3,741	3,679	3,618	3,557	3,496	3,434	3,373	3,312

Relative change from base value

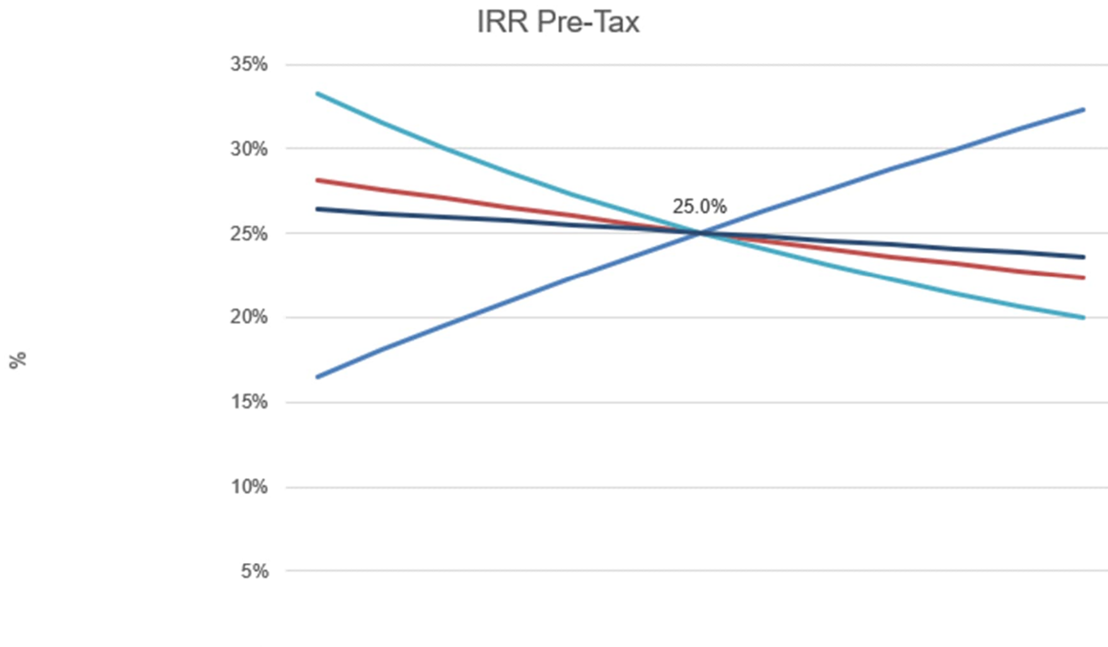
Figure 22.1: NPV @ 8% Pre-Tax Sensitivity



	-30%	-25%	-20%	-15%	-10%	-5%	0%	5%	10%	15%	20%	25%	30%
LHM Price	893	1,130	1,367	1,602	1,837	2,071	2,305	2,540	2,773	3,006	3,240	3,472	3,705
USD/CAD exchange rate	2,595	2,547	2,499	2,451	2,403	2,354	2,305	2,257	2,208	2,160	2,111	2,063	2,014
Initial Capital Cost	2,743	2,670	2,598	2,525	2,452	2,379	2,305	2,232	2,158	2,084	2,010	1,936	1,862
Operating Cost	2,557	2,516	2,474	2,432	2,390	2,348	2,305	2,263	2,221	2,179	2,137	2,095	2,053

Relative change from base value

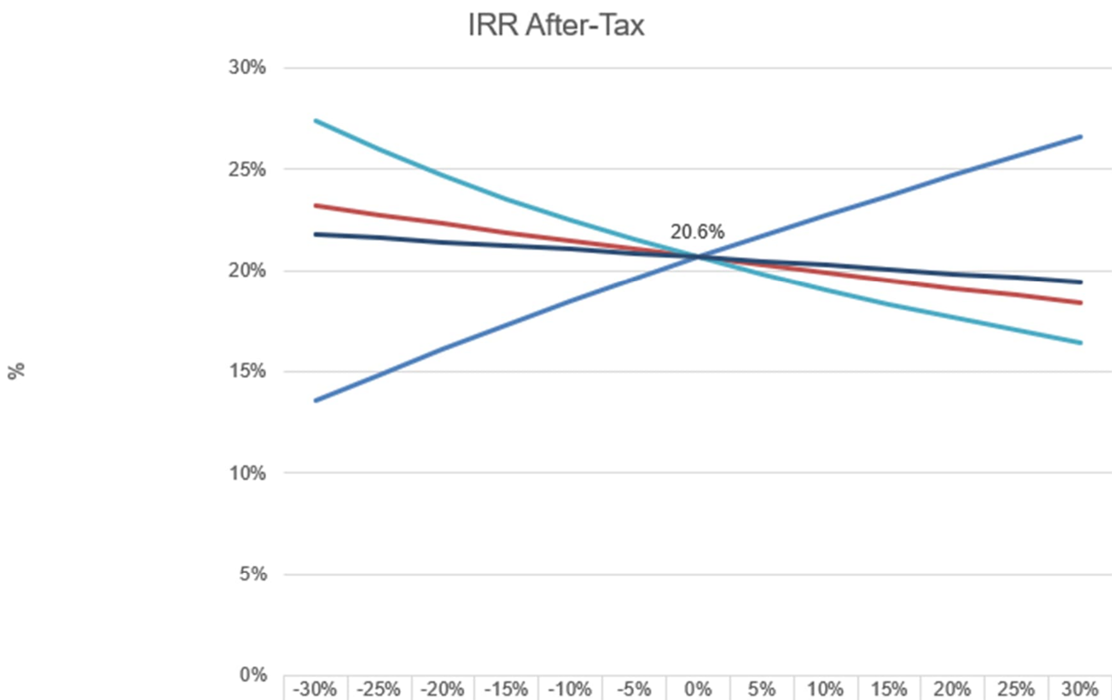
Figure 22.2: NPV @ 8% After-Tax Sensitivity



	-30%	-25%	-20%	-15%	-10%	-5%	0%	5%	10%	15%	20%	25%	30%
LHM Price	16.5%	18.1%	19.6%	21.0%	22.4%	23.7%	25.0%	26.3%	27.6%	28.8%	30.0%	31.1%	32.3%
USD/CAD exchange rate	28.2%	27.6%	27.1%	26.5%	26.0%	25.5%	25.0%	24.6%	24.1%	23.6%	23.2%	22.8%	22.3%
Initial Capital Cost	33.3%	31.6%	30.0%	28.6%	27.3%	26.1%	25.0%	24.0%	23.1%	22.2%	21.4%	20.7%	19.9%
Operating Cost	26.4%	26.2%	26.0%	25.7%	25.5%	25.3%	25.0%	24.8%	24.6%	24.3%	24.1%	23.8%	23.6%

Relative change from base value

Figure 22.3: IRR Pre-Tax Sensitivity



	-30%	-25%	-20%	-15%	-10%	-5%	0%	5%	10%	15%	20%	25%	30%
LHM Price	13.5%	14.8%	16.1%	17.3%	18.4%	19.6%	20.6%	21.7%	22.7%	23.7%	24.7%	25.6%	26.6%
USD/CAD exchange rate	23.2%	22.8%	22.3%	21.9%	21.5%	21.0%	20.6%	20.2%	19.9%	19.5%	19.1%	18.8%	18.4%
Initial Capital Cost	27.4%	26.0%	24.7%	23.6%	22.5%	21.5%	20.6%	19.8%	19.0%	18.3%	17.7%	17.0%	16.4%
Operating Cost	21.8%	21.6%	21.4%	21.2%	21.0%	20.8%	20.6%	20.4%	20.2%	20.0%	19.8%	19.6%	19.4%

Relative change from base value

Figure 22.4: IRR After-Tax Sensitivity

The NPV sensitivity to discount rate is shown in Figure 22.5.

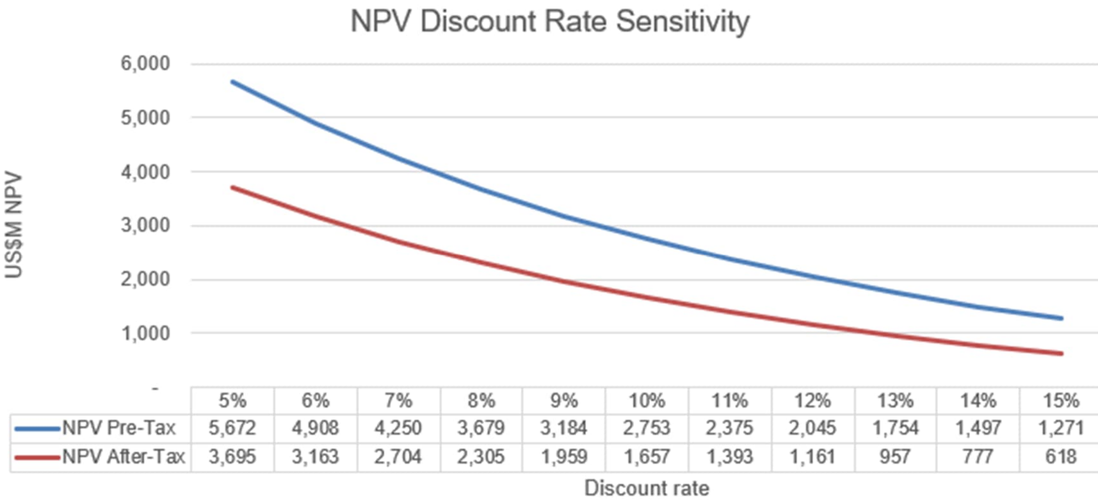


Figure 22.5: NPV Discount Rate Sensitivity

The reader is cautioned that the 98% lithium recovery used in this analysis has not yet been proven at commercial scale (see Section 25.6.4 Recovery Methods Risks). As such, the sensitivity around recovery is particularly important. In general, each 1% absolute drop in recovery decreases modeled pre-tax and after-tax NPV by US$62M and US$42M, respectively, and decreases pre-tax and after-tax IRR by 0.24% and 0.20%, respectively.

23. Adjacent Properties

This section discusses mineral properties that occur outside of the Boardwalk Property. The QP has been unable to verify the information and that the information is necessarily indicative to the mineralization on the Property that is the subject of the Technical Report.

Adjacent Alberta Metallic and Industrial Mineral Permits in the vicinity of the Boardwalk Property are presented in Figure 23.1. As of the Effective Date of this Technical Report, adjoining Mineral permits held by other exploration companies occur to the northwest and southwest of the Boardwalk Property. Other non-adjacent mineral permit holders occur southeast and west of the Boardwalk Property.

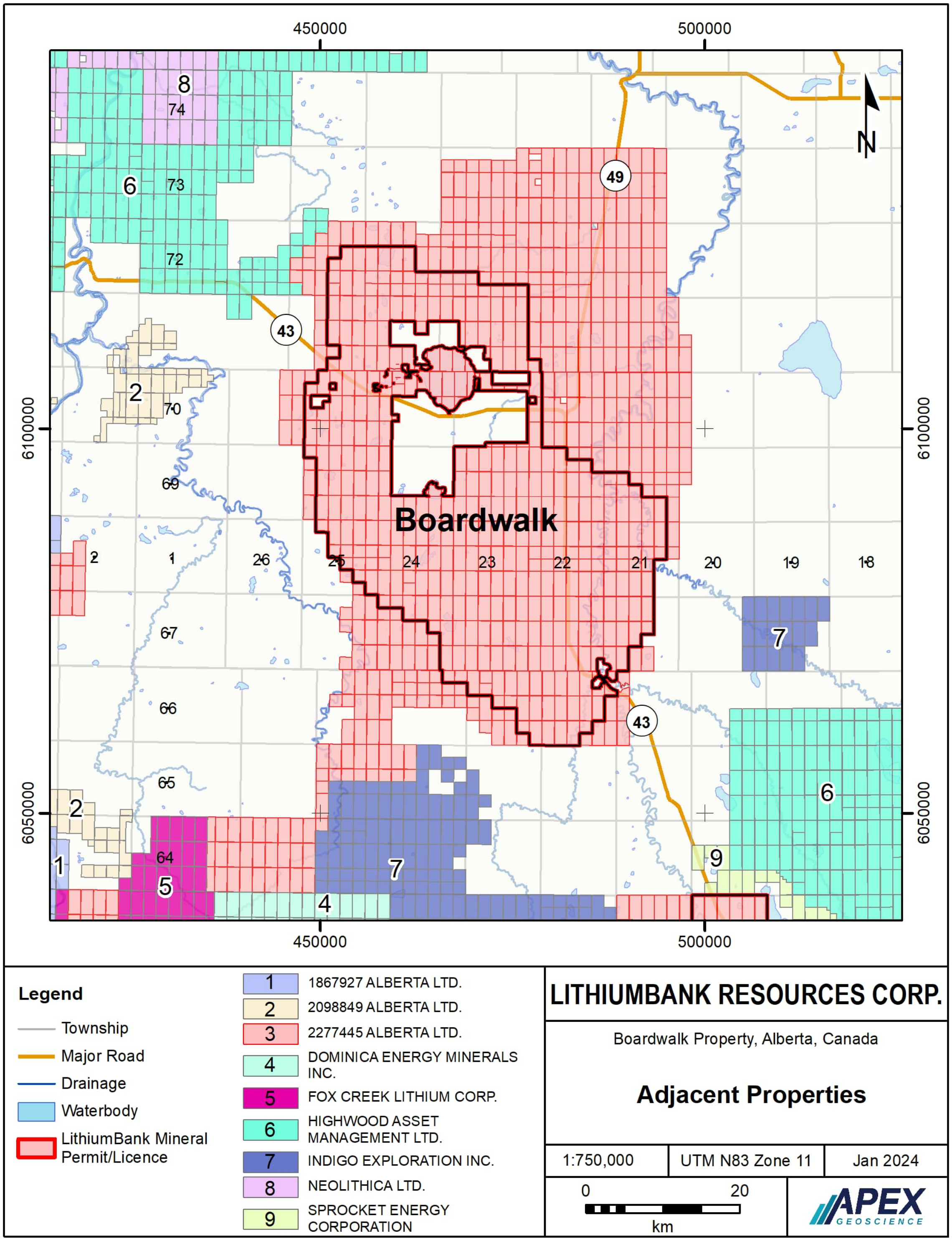


Figure 23.1: Adjacent properties in the Boardwalk Property

The adjacent mineral permits to the northwest are held by Highwood Asset Management Ltd. (Highwood) and Total Petroleum Land Services Ltd. (Total Petroleum).

Highwood's current activities include industrial metals and minerals, oil production and oil midstream spaces. Highwood announced an inferred Li-brine resource estimate technical report on 28 February 2022, at their Drumheller Property in south-central Alberta (Highwood Asset Management Ltd., 2022). It is not known if Highwood has conducted any mineral investigations in their land position adjacent to LithiumBank.

Total Petroleum has been assisting clients with land and mineral acquisitions since 2002 (https://totalpetroleum.ca) and there is no other information related to these mineral permit(s).

The adjacent mineral permits to the southwest are held by Indigo Exploration Inc. (Indigo), Dominica Energy Minerals Inc., Fox Creek Lithium Corp., and two Alberta Ltd. Numbered companies. Indigo announced the recent acquisition of Li-brine mineral permits in central Alberta on October 2022 (Indigo Exploration Inc., 2022).

Dominica Energy Minerals Inc. and Lithium Power Corp. are subsidiaries of Empire Rock Minerals Inc., the latter of which is exploring Devonian brine for the potential to extract lithium, potassium, boron, bromine, magnesium, and other elements of interest from saline formation water (Empire Rock Minerals Inc., 2017).

To the best of the author's knowledge, there is no current company information for Fox Creek Lithium Corp., or the two Alberta numbered companies.

Highwood and Indigo also have mineral permits that occur southeast of the Boardwalk Property along with Sprocket Energy Corporation. The Alberta numbered company, 2098849 Alberta Ltd., also has a cluster of mineral permits that occur approximately 20 km west of the Boardwalk Property. A search of these company websites and mineral assessment reports at Alberta Energy does not provide any exploration information related to these permits and the author is not aware of the potential commodity being explored for.

To the best of the author's knowledge there are no known advanced metallic mineral projects in the vicinity of LithiumBank's Boardwalk Property. Aggregate quarries are scattered throughout northern Alberta with their activity level dependent on proximal roadbuilding and/or municipal and energy industry infrastructure projects.

In contrast to mineral projects, the area is dominated by the oil and gas sector with operations that include active (pumping oil and flowing gas), suspended, abandoned wells. In Alberta, rights to metallic and industrial minerals, to bitumen (oil sands), to coal and to oil/gas are regulated under separate statutes, which collectively make it possible for several different 'rights' to coexist and be held by 'different grantees' over the same geographic location (see Section 0).

24. Other Relevant Data and Information

There is no other relevant data pertinent to the proposed project.

25. Interpretation and Conclusions

25.1 Qualified Person Opinion on LithiumBank's Exploration Programs

LithiumBank's 2021 exploration work included:

1. A brine sampling program in which a total of 44 brine samples were collected from 4 oil and gas wells and yielded between 54.9 mg/L Li and 77.6 mg/L Li with an average of 69.9 mg/L Li. LithiumBank's 2021 assay brine program verified the historical geochemical results, and it is the QP's opinion that the LithiumBank and the historical Li-brine analytical results are reasonable and sufficient for use in mineral resource estimation processes.
2. Re-interpreted 67 line-kilometres of 2-D seismic data that helped to develop a better understanding of the dimensions of the Leduc Formation reefal buildups and the underlying structural geology that may be responsible for the location and development of the reefs and could potentially act as sources of fluid flow of hot geothermal fluids that may be enriched in lithium from the crystalline basement and/or clastic units overlying the basement.
3. A hydrogeological characterization study determined a representative average effective porosity value for the Leduc Formation reef at the Boardwalk Property of 5.3% based on the number of effective (n=99) and total (n=3) porosity measurements. Using a drill stem test permeability of 19 mD, the best estimate from the existing data of calculated transmissivity is 7.4 m^2/day with a storativity of 8.0 × 10-4. A hypothetical well with the average available head of 2,009 m of formation water completed in an aquifer with a transmissivity of 7.4 m^2/day would have a 20-year estimated yield of approximately 7,000 m^3/day using the Farvolden method and the representative hydraulic properties from the Leduc Formation.

The QPs have reviewed the adequacy of the geochemical, stratigraphic, hydrogeological, and mineral processing information discussed in this Technical Report and found no significant issues or inconsistencies that would cause one to question the validity of the data.

The QP is satisfied to include the exploration data including wells litho-logs, brine sample assays, effective porosity (equivalent to specific yield within a subsurface, confined aquifer), and the modal abundance of brine within the Sturgeon Lake Reef Complex for the purpose of resource modeling, evaluation and estimations as presented in this report.

There is collective agreement from a multi-disciplinary team that include geologists, hydrogeologists, and chemical engineers with relevant experience in the geology of the Western Canada Sedimentary Basin, brine geology/hydrogeology, and Li-brine processing that the LithiumBank lithium-brine project has reasonable prospects for eventual economic extraction of lithium from the Leduc Formation aquifer brine at the Boardwalk Property.

25.2 Resource Estimation Conclusions

The Boardwalk Leduc Formation Li-brine resources are classified as 'Indicated' and 'Inferred' Mineral Resources in accordance with CIM definition standards and best practice guidelines (2019, 2014) and the disclosure rule NI 43-101. The resource estimation is presented as a total (or global value), and was estimated using the following relation in consideration of the Leduc Formation aquifer brine:

Lithium Resource = Total Brine Aquifer Volume X Average Porosity X Percentage of Brine in the Pore Space X Average Concentration of Lithium in the Brine.

A single 3-D wireframe of the Leduc Formation aquifer domain was created using the grid surfaces of the top and base of the Leduc Formation within the 3-D geological model. The 2-D strings were connected to create a solid 3-D wireframe of the Leduc Formation aquifer. The indicated resource area depicts the outline of the Sturgeon Lake South Oilfield, which is documented in both the well data and oil and gas reservoir production studies. Only those parts of the Sturgeon Lake Reef Complex that occur within the LithiumBank property were used in the resource estimate process. The 3-D closed solid polygon wireframes of the Leduc Formation aquifer domain were used to calculate the volume of rock, or the aquifer volume. The Leduc Formation domain aquifer volumes underlying the Boardwalk Property In the indicated and inferred resource areas is 19.94 km^3 and 305.00 km^3, respectively.

The brine volumes are calculated for the Leduc Formation aquifer domain and resource areas by multiplying the aquifer volume (in km^3) times the average porosity times the percentage of brine assumed within the pore space. Using an average porosity value of 5.3% and the average modal abundance of brine in the Leduc formation pore space percentage of 98%, the Leduc Formation aquifer domain brine volume in the indicated and inferred resource areas is 1.04 km^3 and 15.84 km^3.

Average Leduc Formation aquifer brine lithium concentrations of 71.6 mg/L Li and 68.0 mg/L Li were selected for the indicated and inferred resource estimation calculations. The resource estimations were completed and reported using a cutoff of 50 mg/L Li.

Mineral resources are not mineral reserves and do not have demonstrated economic viability. There is no guarantee that all or any part of the mineral resource will be converted into a mineral reserve.

The Boardwalk Leduc Formation Li-brine resource estimations predict:

- A globally (total) indicated Li-brine resource of 74,000 tonnes of elemental Li, which is equivalent to 395,000 tonnes LCE (Figure 14.10).
- A globally (total) inferred Li-brine resource estimates 1,077,000 tonnes of elemental Li, which is equivalent to 5,734,000 tonnes LCE (Figure 14.11).

25.3 Well Network Summary

The subsurface recovery method for lithium extraction utilizes deep wells to produce the lithium enriched brine and reinject the depleted brine from the Leduc formation. The well network to supply 250,000 m^3/day lithium brine requires a total of 100 wells, where 50 are production wells and 50 are reinjection wells for depleted brine. The wells are to be located on 23 multi-well surface pads, which minimizes the surface footprint.

The well network is designed to optimize the reservoir (aquifer) available drawdown for a 20-year period of full production capacity of 250,000 m^3/day lithium brine and reinjection of 255,404 m^3/d lithium-depleted brine. The injection rates are limited by the maximum well head pressure (WHP) as defined by AER Directive 51.

The wells are planned to have deviated trajectories to hit the bottomhole target while multiple wells are drilled from the same surface pad. The well design is based on proven technologies and practices from the oil and gas industry. The production wells require artificial lift to produce the brine to surface, where Electrical Submersible Pumps (ESP) are recommended as the best choice. The pumps are expected to require 1 MW per pump for power requirements.

The drilling of the 100 wells is expected to take two years with the use of three drilling rigs. This includes the construction of the surface pads and road access, drilling, casing, and completion of the wells.

25.4 Lithium Extraction and Processing

25.4.1 Lithium Extraction

A bench scale test work program was carried out to understand the selectivity of Go2Lithium's DLE process for lithium in the brine samples from the Boardwalk Lithium Brine project. Process inputs were generated to be used for process design of the DLE circuit.

The Qualified Person for the lithium extraction process concludes that the adopted DLE technology in this technical report has demonstrated in the laboratory bench scale that it can be used to selectively extract lithium from the brine to generate a concentrated lithium stream with a significantly reduced flow rate, which is beneficial for downstream treatment to produce battery grade lithium materials.

25.4.2 Lithium Plant

A series of steps are designed in the lithium extraction process from the brine to produce battery grade lithium hydroxide monohydrate. After the H_2S mitigation treatment and the TSS/TOC removal steps, the volume of the brine is significantly reduced through DLE ion exchange technology for treatment in the form of an eluate solution which contains higher lithium concentration and significantly reduced impurities. The eluate solution is concentrated and polished to generate a lithium concentrate that is suitable to feed into the lithium sulfate electrochemical process. During this step, lithium sulfate is converted into lithium hydroxide, which is transferred to a two-stage crystallization circuit to produce battery grade lithium hydroxide monohydrate crystals. The crystals are then dried and packaged for short-term storage prior to shipment for sale.

25.5 Economics

The PEA base case generates a sufficiently positive after-tax NPV and IRR to support continuation to the next stage of project development activities.

25.6 Risks, Opportunities, and Uncertainties

Potential project risks and uncertainties are outlined in the subsections below.

25.6.1 General Project Risks

- Market price volatility is a risk until contracts are executed.
- The capital and operating cost estimates carry inherent risk due to the preliminary nature of AACE Class 5 estimates.

25.6.2 Property and Resource Estimation Risks and Uncertainties

The ability to perform exploration work at the Boardwalk Property is dependent on LithiumBank having continued access to existing oilfield infrastructure in which the Leduc Formation aquifer brine is pumped upward from depths of >2,340 m upward to the Earth's surface for assay sampling, mineral processing test work, and for consideration of any future commercial Li-brine extraction facility.

On 14 May 2021, LithiumBank finalized a brine access agreement with the major Petro-operator in the Sturgeon Lake Oilfield. The agreement permitted LithiumBank to reopen and access Devonian brine from the suspended oil and gas infrastructure and conduct exploration tasks that can advance the property such as additional assaying and more importantly mineral processing test work toward recovery of lithium.

With respect to long-term access to the brine, the main Petro-operator at the Sturgeon Lake Oilfield has suspended their wells due to any several of reasons. The fact that the wells are suspended should, in no way, undermine the fact that the Leduc Formation aquifer brine does contain elevated quantities of lithium and/or the Li-brine prospect. The fact the wells are suspended does not mean the oilfield will never go into production again. The Petro-operator could choose to wait for improved technology, infrastructure, or commodity pricing before continuing production.

As a mitigation strategy, and in the formulation of the preliminary economics presented in this technical report, LithiumBank plans to acquire an existing oil or gas well(s) along with its associated infrastructure brine hosted license rights. LithiumBank therefore intends to secure the Company's access to a continuous source of brine at the Boardwalk Property.

With respect to the hydrogeological assessment, any prediction of long-term yield is subject to uncertainty due to the uncertainty associated with the hydraulic parameters summarized in Section 14.3. Despite the prediction uncertainty, the calculated long-term yield suggests there is a potential to extract substantial quantities of brine from the Leduc Formation.

With respect to the mineral resources, the Li-brine resource estimations presented in this technical report are subject to change as the project achieves higher levels of confidence in the spatial extent of the aquifers, mineralization, metals-from-brine recovery processes, DLE technological development, and utilization of the appropriate cutoff value in relation to extraction results.

25.6.3 Well Related Risks

1. Brine production or injection rates are different than expected.
   a) If lower, then more wells would be required. If higher, then the pumps may not be sized properly and less wells required.
   b) Mitigation involves flow testing a test well before final design.
   c) If injection stream volumes are higher due to additional lithium depleted brine from water usage in the process, it is possible that an additional injection well will be required, but that cost was not included in the PEA.
2. Gas is produced with the brine and contains sour components.
   a) Safety concern related to sour gas.
   b) Pipeline and facility design does not account for sour gas production and handling.
   c) Mitigation is a flow test to incorporate results into process design and safety plan.
3. Development of scale at sandface, in wells, or in pipeline system from/to the wells.
   a) Scale can impair injectivity and cause back-up of depleted brine at the CPF.
   b) If scale is in the well or sandface, then a scale treatment is needed which causes downtime and costs.
   c) Mitigation is scale prevention program. To design the program, sample of the brine and compatibility with reservoir fluids should be tested before start-up of wells.

25.6.4 Recovery Methods Risks

25.6.4.1 Lithium Extraction

- The use of ion exchange technology for direct lithium extraction, in particular the sorbent used in this application has not been demonstrated at a commercial scale. The process design inputs were based on a preliminary bench-scale lab test.
- It is highly recommended that the lithium extraction technology be thoroughly tested at the pilot plant scale and, if proven viable, demonstration plant scale in the future project development phases, to mitigate the risk of the possible performance issues associated in commercial application.
- The co-loading of impurities on the DLE sorbent could be higher than what is currently considered due to the temperature variation in the feed. The consequence is that the

reagent efficiency decreases, and higher reagent consumption would result. Therefore, this could result in higher operating cost. The impurity co-loading for the current PEA was quantified through test work.

- The DLE sorbent replacement frequency used in this technical report is determined by the DLE sorbent supplier based on past project lab-based experience. The sorbent longevity and attrition test has not been completed to determine the replacement frequency of the sorbent for LithiumBank's Boardwalk Lithium Brine samples. Therein lies a risk that that sorbent replacement requirement could be different than initially estimated, potentially resulting in a higher operating cost.

25.6.4.2 Lithium Plant

- The lithium samples that were used for the test work were taken at a relative higher depth than the intended drilled depth for actual process which will be below the hydrocarbon zone. The actual brine may contain different levels of H_2S concentration and hydrocarbon concentration identified and adopted in this study. As a result, in the case where the H_2S and hydrocarbon contents exceed the design capacity in the pretreatment stages, the system could be overloaded with hindered performance. It is recommended that future engineering phases investigate based on samples taken from the intended drilled depth for actual process and brine chemistry variabilities be studied and analyzed to mitigate the discussed risks.
- Overall lithium recovery of 98% may not be sustainable over the life of the project, or the allocated capex for the lithium extraction circuit may be insufficient to account for the targeted recovery of lithium considered. This has implications on the overall economics of the project. This will be evaluated further in the future pilot testing and next phase of engineering development.
- The co-loading of impurities on the DLE sorbent could be higher than what is currently considered, or the selectivity of the sorbent could be lower. The consequences on the downstream lithium plant would include higher reagent consumption and could potentially require additional unit operations to be added to ensure that product quality is maintained. Therefore, this could result in higher capital and operating costs.
- A lithium sulfate electrochemical process has not been commercially demonstrated, and as result there is an inherit technology maturity risk associated with this processing step. In the subsequent phases of engineering design, this circuit will be tested/piloted.
- Fluctuations in reagent pricing could impact the operating costs. Long term reagent supply contracts will need to be established to mitigate the risks.
- Materials of construction selection is preliminary for the equipment in the lithium extraction processing plant. Data from similar applications has been relied upon at the stage of the project. Some areas apply assumptions based on the best knowledge of the QP's at this stage of the project development to require exotic materials due to the nature

of the streams being handled, and it is considered necessary to validate those selections in the future project phase with more definition using corrosion test work.

- A 90% operating factor is considered for the process design. In the case where lower operating factor is achieved in the process, the plant uptime decreases, which could result in a reduction in lithium production. A suitable design factor was applied in the equipment sizing and selection in the study and buffer capacities were considered in several process areas. It is recommended that in future engineering phases a study on plant availability, utilization and reliability evaluation be carried out to establish the optimal operating basis.

25.6.5 Opportunities

25.6.5.1 Property Opportunities

- Hundreds of suspended oil and gas wells are within the proposed area of barren brine disposal. These suspended wells could potentially be used as disposal wells for barren brine. A significant opportunity exists to reduce the number of new disposal wells required by repurposing suspended oil and gas wells.
- By collecting addition porosity and permeability data by way of drilling through the Leduc formation, LithiumBank can potentially improve the transmissivity value of the production zone. Improved transmissivity could result in reducing the total number of disposal and production wells required.

25.6.5.2 Economics

- The Government of Canada announced an Investment Tax Credit for Clean Technology Manufacturing in its Budget 2023. This refundable investment tax credit would be equal to 30% of the capital cost of depreciable property used for eligible activities, which includes critical minerals extraction. This credit could positively impact project economics.

25.6.5.3 Recovery Methods

- LithiumBank entered into a Memorandum of Understanding ("MoU") with ZS2 Technologies that presents several potential benefits to both the financial model and the environmental impact. The MoU will enable ZS2 to deploy their proprietary and patented CO_2 Direct-Air-Capture ("DAC") technology to capture carbon dioxide emissions directly from proposed power facility at the Boardwalk project. ZS2 will also further process treated brine to collect magnesium (Mg) and calcium (Ca) for use in their proprietary magnesium cement products (magnesium is also a critical mineral as indicated in the Canadian Critical Minerals List). Initial indications suggest that up to 10% of barren brine from the DLE facility could be used in this process. The carbon capture process may reduce the carbon footprint of this project and could result in reduction in the CAPEX in the well costs. This opportunity will be explored and evaluated in the next phase of the project.

- Future piloting of the DLE flowsheet using LithiumBank's Boardwalk feed brine may identify a reduction in adsorption contactor stages and/or elution contactor stages. This would have a positive impact on capital cost in this area of the lithium process plant.

25.6.5.4 Power

The gas-powered turbines selected in this study are 80% hydrogen ready at installation. Should there be a readily available supply of hydrogen in the project area LithiumBank could have even greater control over the carbon footprint of the project and further reduce CO_2 emissions.

26. Recommendations

This section has been separated into recommendations that involve exploration (Section 26.1), environmental studies and community consultation (Section 26.2), well optimization (Section 26.3), and mineral processing test work (Section 26.4).

26.1 Exploration

LithiumBank's Boardwalk Property is a property of merit and additional exploration work is recommended. The estimated cost of the exploration work is CDN$ 8.8 million with 10% contingency. The exploration work recommendations and their individual cost estimations are described in Table 26-1 and in the text that follows.

The exploration work relates to the acquisition of existing wells, implementation of reservoir stratigraphic and hydrogeological characterization studies, and continuation of brine sampling programs for assay testing (and mineral processing test work as described in Section 26.4).

With respect to exploration, it is recommended that LithiumBank:

- Acquires a minimum of three existing wells with associated infrastructure to ensure continual brine access for experimental test work.
- Collect additional Leduc Formation aquifer brine samples for further assaying to refine Boardwalk Property Leduc Formation lithium values for use in the resource estimation process, and/or expand, or modify, the current resource areas and classifications. This could include developing new, deeper, brine perforation windows to test Li-brine grades and hydrogeological conditions in the lower portions of the Leduc Formation below the current hydrocarbon production interval.
- Conduct downhole geological, geophysical, and hydrogeological studies - including a pump test on at least one well - to provide added confidence in the understanding of the geological and hydrogeological conditions within the Leduc Formation reservoir. It is recommended that a minimum of three well tests be conducted with at least one new well being drilled in the main part of the development area to gather the following information: core samples across the Leduc formation; fluid samples from the Leduc brine to confirm water/gas composition and fluid compatibilities; flow and injectivity tests including pressure analysis; and a core analysis for particle size distribution for completion design.

Also recommended are packer tests to analyze the relative contribution of correlated geologic units the Leduc Formation to determine flow characteristics. To minimize interference during the fluid level and pressure surveys, the pump test well(s) should be at least 1,500 m from any producing or injecting well site that has been active in the last five years. The aquifer test should be conducted on three days of pumping followed by no less than six days of recovery.

- Lastly, LithiumBank should continue assess and disclose material matters through technical reporting in accordance with CIM definition standards and best practice guidelines (2014, 2019) and the disclosure rule NI 43-101.

Table 26-1: Future Exploration Work Recommendations

Item number	Description	Cost estimate (CDN$)
1	Acquire a minimum of 3 existing wells with associated infrastructure to ensure brine access for experimental test work.	$7,000,000
2	Continuation of the brine assay sampling and testing program.	$240,000
3	Conduct downhole geological, geophysical, and hydrogeological studies - including a pump test on at least one well - to provide added confidence in the understanding of the Leduc Formation reservoir.	$450,000
4	Ongoing technical reporting to document material milestones that could include upgraded resource classifications and/or a Preliminary Feasibility Study.	$300,000
	Sub-total	$7,990,000
	10% contingency	$799,000
	Total	**$8,789,000**

26.2 Environmental Studies, Permitting and Social or Community Impact

Future work should include the ongoing development, refinement and implementation of a community engagement plan including indigenous groups and community stakeholders. This should also include initial liaison with the regulatory agencies, primarily the Alberta Energy Regulator (AER) as the full lifecycle regulator for the province of Alberta’s brine-hosted mineral resources. A focus of this liaison should be to determine the potential need for an Environmental Impact Assessment to be completed of the project or components of the project, such that the overall scope and timeline of environmental studies can be determined.

26.3 Well network

The capital cost to install the wells is a substantial part of the total project costs. To refine and optimize the well costs, it is recommended that the following steps be taken; work with vendors and technology developers to find a smaller diameter ESP which could allow for smaller diameter wellbores; investigate re-use or well extensions from existing oil and gas wells that have good well integrity; investigate drilling options that manage the supply chain and service contracts to lower well drilling costs; and evaluate if less multi-well pads could be used which requires extended deviated wells.

26.4 Lithium Extraction and Process

26.4.1 Lithium Extraction

- Further develop test work to evaluate the sorbent performance, as well as optimize reagent and water consumption for the system at a larger scale for a range of brine qualities.
- Further bench scale test work to assess the longevity of the DLE sorbent to better define the sorbent replacement frequency.
- Pilot testing on the DLE loading/elution cycles to validate and optimize the process conditions for a range of brine qualities.

26.4.2 Lithium Plant

In the next engineering phase, a prefeasibility study is recommended with the following activities regarding the lithium processing plant:

- Test work to define key design criteria for major unit operations, such as filtration (including brine pretreatment and media filtration).
- Pilot test on the feasibility of the lithium sulfate electrochemical process.
- Tradeoff studies to compare the process flowsheets to produce battery grade lithium carbonates and lithium hydroxide monohydrate.
- Water optimization trade-off.
- Prioritizing and selecting the favored options from the tradeoff studies to update the process flowsheet.
- Development of process flow diagrams for the lithium processing plant.
- Plant location selection study.
- Plant layout.
- Development of a Class 4 capital and operating cost estimate.
- Preliminary project implementation schedule.
- Financial evaluation and risk assessment.
- Preparation of the preliminary work plan for next phase feasibility study.
- Assessment of the project’s viability to process to the feasibility study phase.

The total estimate cost for the next phase prefeasibility study is USD 2,500,000 to 3,000,000.

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