E3 Lithium 43-101 Technical Report: Lithium Resource Estimate

2023

BASHAW DISTRICT PROJECT, CENTRAL ALBERTA

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Forward Looking Information Statement

This report contains forward-looking statements regarding E3 Lithium Ltd. ("E3 Lithium" or "the Company") and the potential of its current and future projects. Generally, forward-looking statements can be identified by the use of forward-looking language such as "plans", "expects", "budgets", "schedules", "estimates", "forecasts", "intends", "anticipates", "believes", or variations of such words and phrases, and statements that certain actions, events or results "may", "could", "would", "might", "will be taken", "will occur" or "will be achieved". Forward-looking statements are based on the opinions and estimates of E3 Lithium as of the date such statements are made. Forward-looking statements are subject to known and unknown risks, uncertainties and other factors that may cause the actual results, levels of activity, performance or achievements of E3 Lithium to be materially different from those expressed or implied by such forward-looking statements, including, but not limited to, risks related to: E3 Lithium' ability to effectively implement its planned exploration programs; unexpected events and delays in the course of E3 Lithium' exploration and drilling programs; changes in project parameters as plans continue to be refined; the ability of E3 Lithium to raise the capital necessary to meet its milestones, conduct its planned exploration programs and to continue exploration and development on its properties; the failure to discover any significant amounts of lithium or other minerals on any of E3 Lithium' properties; the fact that E3 Lithium' properties are in the exploration stage and exploration and development of mineral properties involves a high degree of risk and few properties which are explored are ultimately developed into producing mineral properties; the fact that the mineral industry is highly competitive and E3 Lithium will be competing against competitors that may be larger and better capitalized, have access to more efficient technology, and have access to reserves of minerals that are cheaper to extract and process; the fluctuations in the price of minerals and the future prices of minerals; the fact that if the price of minerals deceases significantly, any minerals discovered on any of E3 Lithium' properties may become uneconomical to extract; the continued demand for minerals and lithium; that fact that resource figures for minerals are estimates only and no assurances can be given than any estimated levels of minerals will actually be produced; governmental regulation of mining activities and oil and gas in Alberta and elsewhere, including regulations relating to prices, taxes, royalties, land tenure, land use, importing and exporting of minerals and environmental protection; environmental regulation, which mandate, among other things, the maintenance of air and water quality standards and land reclamation, limitations on the general, transportation, storage and disposal of solid and hazardous waste; environmental hazards which may exist on the properties which are unknown to E3 Lithium at present and which have been caused by previous or existing owners or operators of the properties; reclamation costs which are uncertain; the fact that commercial quantities of minerals may not be discovered on current properties or other future properties and even if commercial quantities of minerals are discovered, that such properties can be brought to a stage where such mineral resources can profitably be produced therefrom; the failure of plant or equipment processes to operate as anticipated; the inability to obtain the necessary approvals for the further exploration and development of all or any of E3 Lithium' properties; Risks inherent in the mineral exploration and development business; the uncertainty of the requirements demanded by environmental agencies; E3 Lithium' ability to hire and retain qualified employees and consultants necessary for the exploration and development of any of E3 Lithium' properties and for the operation of E3 Lithium' business; and other risks related to mining activities that are beyond E3 Lithium' control. Although E3 Lithium has attempted to identify important factors that could cause actual results to differ materially from those contained in the forward-looking statements in this presentation, there may be other factors that cause results not to be as anticipated, estimated or intended. There can be no assurance that such statements will prove to be accurate, as actual results and future events could differ materially from those anticipated in such statements. Accordingly, readers should not place undue reliance on forward-looking statements contained in this presentation. E3 Lithium does not undertake to update any forward-looking statements except in accordance with applicable securities laws. Unless otherwise indicated, Chris Doornbos, P. Geo., President and CEO at E3 Lithium Ltd. and a Qualified Person under National Instrument 43-101, has reviewed and is responsible for the technical information contained in this report[1].

[1] Certain scientific and technical information contained herein is derived from the Inferred Mineral Resources outlined in NI 43-101 report for the Clearwater Lithium Project PEA (September 17, 2021), North Rocky Property (December 22, 2017) and the Measured & Indicated (M&I) Mineral Resource outlined in March 21, 2023 press release.

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1. Summary

E3 Lithium (E3, or the Company), an emerging lithium developer and leading lithium extraction technology innovator, is a public company with a head office located in Calgary, Alberta. The company trades on the Toronto Venture Exchange, as well as the OCT and Frankfurt markets (TSXV: ETL | FSE: OU7A | OTCQX: EEMMF).

The purpose of this technical report update is to incorporate drilling data from the 2022 drill program, including additional sampling and a flow test, ongoing reviews and analyses of core samples across the Bashaw District (BD) and describe the development of a comprehensive geological model which enabled enhanced geostatistical 3D analysis. The ongoing data review and technical analysis included additional core description work and petrophysical modeling, the evaluation and addition of more LAS data in North Bashaw and sampling data obtained in the lower and middle Leduc reservoir. E3 conducted routine and special core analysis on core obtained from 2022 drill program to calibrate the middle/lower Leduc porosity and permeability and support the estimation of effective porosity.

E3 retained Alex Haluszka, P.Geo., and Daron Abbey, P.Geo., of Matrix Solutions Inc. as Qualified Persons (QPs) to supervise the work and author this technical report on the resource estimate of the BD Project in conformity to National Instrument 43-101 (NI 43-101) standards and Peter Ehren, AUSIMM, of Process and Environmental Consultancy was retained as the QP for Section 13 and joint QP for Sections 25 and 26.

1.1. Property Location and Ownership

E3's Alberta Lithium Project consists of 71 Metallic and Industrial Mineral (MIM) Permits that overlie the Leduc Reservoir in Southern Alberta. All permits are held 100% by 1975293 Alberta Ltd (Alberta Co)[i], a wholly owned subsidiary of E3, and have a total area of 515,601.69 hectares (ha). The BD consists of 46 of E3's 71 MIM Permits, covering 333,608 ha. The total BD is 593,115.5 ha and contains three sub-project areas: Clearwater, Exshaw, and Drumheller (Figure 1).

The authors of this Technical Report have not reviewed the 71 MIM Permits held by E3. The legal and survey validation is not in our expertise, and we are relying on E3's land persons and lawyers to review. Through personal communication with E3, the authors have no reason to question the validity or the good standing of the E3 permits.

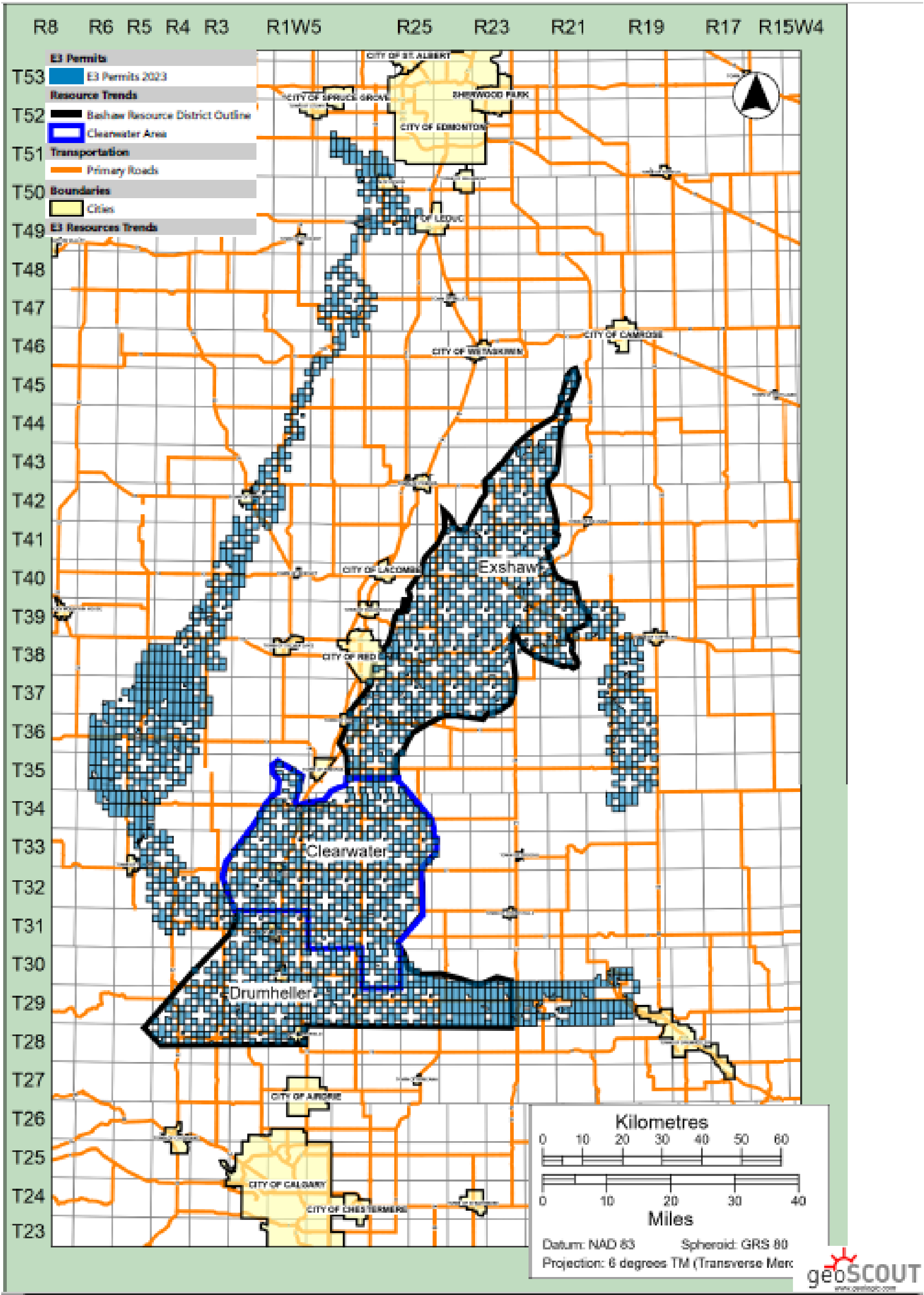

Figure 1: Bashaw District Project Permits (E3, 2023)

1.2. Geology and Lithium Brine Sourcing

The BD is in the southwestern part of the Western Canada Sedimentary Basin (WCSB). In this area, the Upper Devonian (Frasnian) sediments of the Woodbend Group were deposited in a shallow inland sea bounded by the emergent Peace River Arch to the northwest and the West Alberta Ridge to the southwest, creating a barrier between the sea and the open ancestral Pacific to the west (Potma, et al. 2001[ii]). The flooded carbonate platform of Cooking Lake provided structural highs and a favorable environment for the extensive reef buildups of the Leduc Formation. The BD encompasses the Bashaw reef complex, which extends southeast from near Camrose and terminates near Crossfield at the edge of the E3 permit area. The Meadowbrook-Rimbey Leduc reef complex is west of the BD. The Duvernay and Ireton basinal shales and carbonate muds, which conformably encase and overlay the Leduc buildups, create seals for the hydrocarbon pools and the Leduc brine resource. The Leduc limestone deposits are partially to completely replaced by dolomite, a process that enhanced the porosity and permeability of the reservoir. Current data suggests that Cooking Lake remains predominantly limestone. The main oil, gas, and lithium-brine mineralization accumulations in E3's permit area occur in dolomitized reefs of Devonian age at true vertical depths greater than 1,400 meters (m) in the subsurface.

Based on core descriptions, wells logs and the extensive amount of literature that exists for the BD Leduc reef complex, three lithostratigraphic facies (lithofacies) have been interpreted: (1) Leduc reef flat to reef margin facies; (2) Leduc reef interior open lagoon to reef flat facies; and (3) Leduc reef interior restricted to open lagoonal facies. Multiple geostatistical simulations of porosity across the BD have been completed and they show that while porosity is variable and is generally higher in areas associated with reef flat to reef margin facies, connected porosity volumes exist across all facies that E3 believes host producible lithium brine volumes. The interpretation of good connectivity/continuity is further supported by measured pressure continuity across the BD and is described more fully in Section 7.8 Reservoir Dynamics.

1.3. Resource Estimate

The measured and indicated resource estimate was developed in stages:

- Data compilation and review of previous reporting
- Additional core descriptions and reservoir depositional framework/lithofacies analysis
- Drilling of wells including coring, flow testing and collection of brine samples over the vertical profile of the Leduc formation
- Analysis of pressure transient information collected from flow testing
- Routine and special core analysis to support updated reservoir properties
- Updated geological mapping and evaluation of reservoir properties/petrophysics
- Construction of a 3D geomodel to encompass the Leduc formation over the BD
- Geostatistical analysis of key parameters for measured and indicated resource estimate

The mineral resource estimate for the BD is 16,003,000 tonnes of lithium (14 Mineral Resource Estimates). Of this, the Indicated portion of the resource is 9,404,000 tonnes LCE, and the Measured portion of the resource is 6,598,000 tonnes LCE.

E3 is completing additional characterization and sampling work, along with economic analysis, testing and design work on extraction methods in order to support upgrading a portion of the resource to reserve categories (Section 26).

2. Introduction

Throughout this report, E3 utilizes reservoir engineering terminology for most parameters rather than hydrogeological terminology per past reports. This change is aligned with the anticipated recovery method via existing oilfield technologies (wells, pumps, and pipelines) to extract the lithium-rich brine[iii] from the reservoir and supply it to the direct lithium extraction (DLE) technology. In some cases in the report, hydrogeological terms are still favoured. A summary of key terminology is provided in Table 1.

Table 1: Reservoir Engineering versus Hydrogeology Terminology

Reservoir Term(s)	Equivalent Hydrogeological Term	
Reservoir; Net Pay	Aquifer	Hydrostratigraphic Units
Seal	Aquitard	
Recoverable Volume*	Specific Yield*	
Total System Compressibility Product	Specific Storage	
Irreducible Water Saturation	Specific Retention	
Fluid Mobility	Hydraulic Conductivity	
Viscosity-corrected permeability thickness	Transmissivity	
Flow Test	Pumping Test	
Build-up; Shut-in Period	Pumping Test Recovery Period	
Fall-off	Injection Test Recovery Period	

*Recoverable volume relies on reservoir drive mechanisms whereas specific yield assumes gravity drainage. See Section 14.1.3 for further discussion.

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

2.1. Terms of Reference

E3 retained Alex Haluszka, P.Geo., and Daron Abbey, P.Geo., of Matrix Solutions Inc. as QPs supervising and authoring the work for all sections of the resource estimate except for Section 13: Mineral Processing and Metallurgical Testing for the BD Project in conformity to NI 43-101 standards. Peter Ehren, AUSIMM, of Process and Environmental Consultancy was retained as the QP for Section 13 and portions of Section 25 and 26. The report was prepared by E3 under the supervision of the QPs and is to be used by E3 for the purpose of supporting commercial project evaluation and/or financing. E3 prepared the information on the legal description and mineral rights in 4.2 Property Description and 4.3 Property Royalties.

2.2. Sources of Data

The report is based upon information and data collected, compiled, and validated by E3 and reviewed by the QPs. Mineral rights and land ownership information was provided by E3. Information contained within the report was derived from the following:

- E3-supplied exploration maps, logs, laboratory analyses, third-party reports, and field test data
- Original bench tests on collected brine samples
- Oil and gas data compiled by the Government of Alberta
- Published literature (27 References)

Sources of information are listed in 27 References and are acknowledged where referenced in the report text.

2.3. Site Visits

Site visits during field sampling was performed by Alex Haluszka, P.Geo., of Matrix Solutions Inc. on April 28th, and September 15th, 2022. See 12 Data Verification of this report for a description of the site visit.

A site visit was not required by Alex Haluszka, P.Geo., or Daron Abbey, P.Geo., to validate the bulk of the geoscience data utilized in the report as most of the data herein was not sourced by E3 and was instead sourced from the publicly available Alberta Energy Regulator database, collected from decades of oilfield development by various operators. Sampling data utilized in this report was addressed in the April 2022 site visit by Alex Haluszka, P.Geo., when he validated E3's sampling protocols. The September 2022 site visit was to witness and validate the production test on an E3 operated well.

A site visit was not required by Peter Ehren, AUSIMM, to validate the 13 Mineral Processing and Metallurgical Testing data as the review was completed remotely.

3. Reliance on Other Experts

The following third-party subject matter experts (SME) were involved in aspects of the resource evaluation:

Third Party Expert		Scope of Work
SME Name, Title & Designation	**SME Company**	
Alexey Romanov, Senior Manager, Geoscience, PhD., P. Geol. Aaron Weber, Petrophysicist, P. Geol.	Sproule and Associates	Petrophysical analysis and geological modelling
Phil Esslinger, Principal Geoscientist, P. Geol.	Melange Geoscience	Drill Stem Test (DST) analysis
Eva Drivet, President, P. Geol. M. Sc.	Drivet Geological Consulting	Core logging/facies descriptions with E3 staff (Joanie Kennedy, P.Geo.)

Barry Smee, President, Ph.D., P. Geol (BC)	Barry Smee (Smee and Associates)	Provided the certificate and analysis for the certified reference material (CRM)
Darren Kondrat, President, B.Sc., MBA, P. Geoph.	Rockyview Geoservices	Seismic interpretation
Vadim Milovanov, Project Engineer, P. Eng.	S&P Global	Flow test analysis

The QP's reviewed third-party information to confirm that it was completed by qualified experts and properly authenticated. For the geological modelling work completed by Sproule, the QP's reviewed the variogram analysis for porosity and representative porosity realizations and connectivity analysis of geobodies directly using a RESCUE file format and through webmeetings with Sproule and E3.

4. Property Description and Location

4.1. Location

E3's BD Project is located in south-central Alberta between the cities of Edmonton and Calgary (Figure 1). The project area overlies the carbonate reef complex deposits of the Leduc Formation, a hydrocarbon producer and reservoir for brines containing lithium.

4.2. Property Description

E3's BD is 593,115.5 hectares (Ha) and contains 3 Sub-Project areas: Clearwater, Exshaw, and Drumheller (Figure 1). The BD consists of 46 Metallic and Industrial Mineral Permits that overlie the Leduc Formation in Southern Alberta (Figure 2) covering 333,608 hectares (Ha). These 46 permits completely or partially intersect the BD boundary, with 331,847 ha falling within the boundary and 1,760 ha falling outside. The claims are interspersed with privately owned (Freehold) mineral rights. A list of permits associated with the BD can be found in Appendix A.

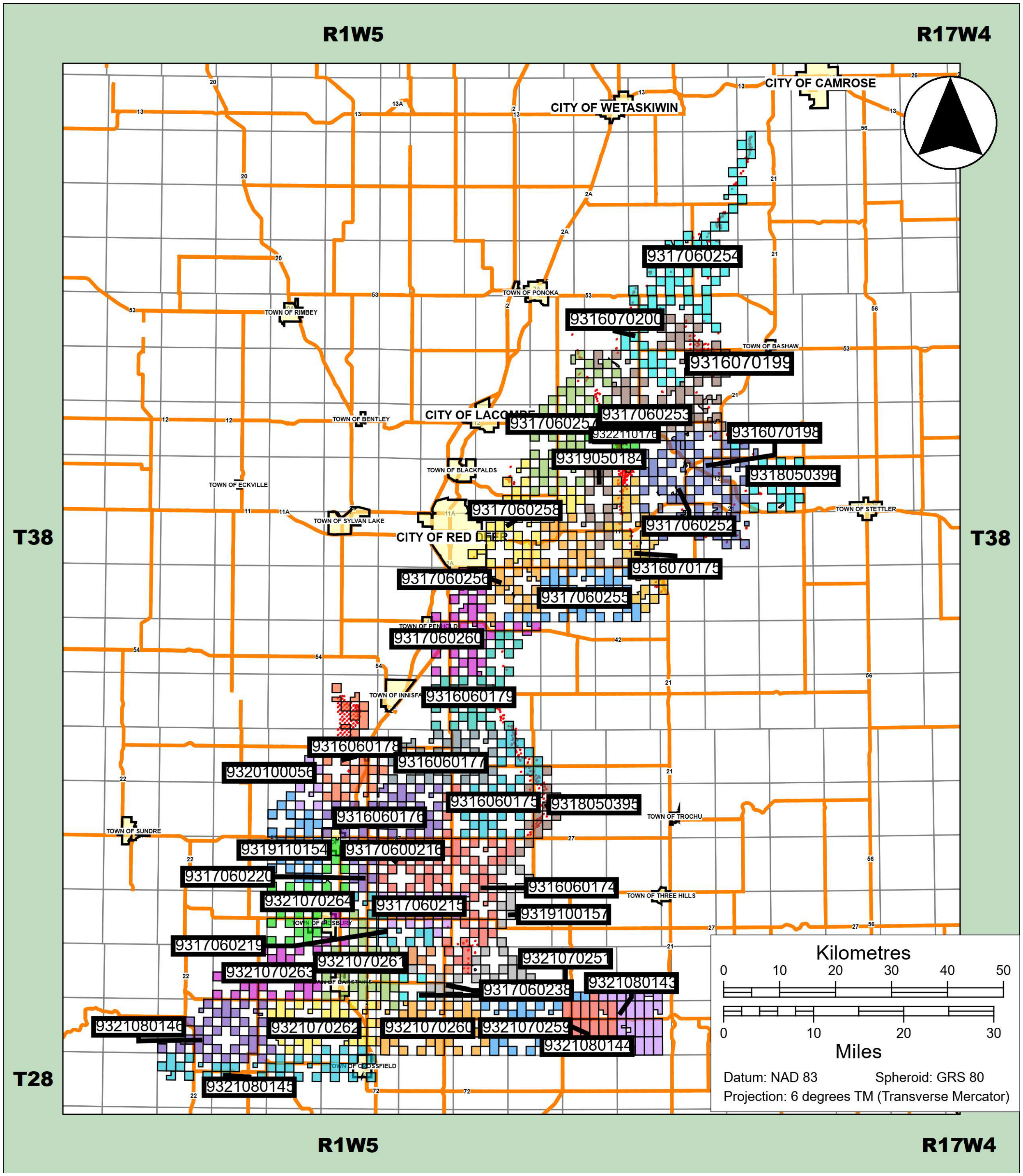

Figure 2: Permits Associated with the Bashaw District Project, Alberta, Canada (E3, 2023)

E3 first staked some of its permit tenure for Alberta Metallic and Industrial Mineral Permits in 2016, and continued with staking for permits until 2022, which granted the explorer the exclusive right to explore for metallic and industrial minerals for seven consecutive two-year terms (total of fourteen years), subject to traditional biannual assessment work on Crown Land. Amendments to the Metallic Industrial Minerals Tenure legislation came into force on January 1, 2023 [iv] which split the MIM (Metallic Industrial

Minerals) permits into Rock-hosted metallic and industrials minerals permits, and Brine-hosted minerals leases. As of January 1st, 2023 all metallic and industrial minerals permits converted to rock hosted minerals permits.

As an eligible rock-hosted minerals permit holder, E3 will apply by December 31st, 2023 to convert the original MIM permits to brine-hosted minerals licenses. These licences will have a non-renewable term of 5 years with an annual rental fee, after which E3 intends to convert to brine-hosted mineral leases[v].

The mineral permits are interspersed with privately owned (Freehold) land, where the subsurface and/or minerals rights are owned by private individuals and/or companies and not the crown. The Freehold mineral rights do not pose an obstacle to brine assay and mineral processing test work within the mineral permits owned by E3, as E3 can take assays and perform testing over areas that they own the permits and extrapolate the data to cover the areas that do not include E3 permits. The reservoir itself is not confined to the E3 permits but spans the whole BD. Since June 23, 2022, E3 has formed a partnership with Imperial Oil with the option to purchase a number of the freehold mineral rights in the area to fill in some gaps within permit area. E3 is confident that appropriate agreements with off-setting freehold mineral owners can be arranged, per AER D56 7.7.12(e)[vi]. Discussions with significant Freehold owners are currently underway. The measured & indicated resource volumes in this report includes all lands within the BD outline, both Crown and Freehold mineral rights.

Overlapping carbon capture and sequestration (CCS) permits have been granted across portions of the BD to allow the evaluation of the Leduc to determine its suitability for CCS projects. E3 is working with the CCS evaluation permit holders to resolve subsurface conflicts and has engaged with Alberta Energy and the Alberta Energy Regulator on this topic. As E3 holds the mineral tenure rights, and the CCS permits are at an early stage (e.g. evaluation rather than development), the resource estimate is proceeding on the assumption that none of the brine-hosting pore space needs to be excluded to account for CCS development.

4.3. Property Royalties

E3 previously held a royalty (signed September 24, 2020) which included the following 8 permits: 9316060174, 9316060175, 9316060176, 9316060177, 9316060178, 9316060179, 9320100056 and 931911015. The agreement outlined a perpetual equal to 2.25% of the gross proceeds from all products that were mined or extracted from the aforementioned permits. E3 had the option to purchase all or a portion of the royalty any time before September 30, 2022 for \$800,000 for the entire 2.25% of the royalty. E3 evaluated the long-term costs of the royalty and decided to purchase it out for the \$800,000 on September 30, 2022.

There are no existing royalties over E3’s permit areas at the time of publication.

4.4. Environmental Issues

E3 currently owns three wellbores in the Bashaw district. Upon application to license/transfer ownership of these wellbores a liability assessment was required to determine risks to public and the environment, and a security deposit was made to the AER to ensure that all future liabilities would be covered. As the owner/operator of these wellbores, E3 is responsible for maintaining the wellbores and will be required to abandon these wells and reclaim these sites as set out in Directive 20[vii], and Directive 90[viii] by the Alberta Energy Regulator, and section 137 of the Environmental Protection and Enhancement Act (EPEA)[ix].

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

5.1. Accessibility

The BD is readily accessible by air and ground transportation (Figure 3). The City of Red Deer (population of 100,844) is located at the junction of Alberta Provincial Highway 2 ("Hwy 2") and Highway 11; Hwy 2 is the main corridor between Edmonton and Calgary and runs North-South directly through the Clearwater Property. There are international airports in Calgary (YYC) and Edmonton (YEG). Red Deer hosts a regional airport (YQF). Major and secondary provincial highways, and all-weather roads developed to support oil/gas infrastructure, occur throughout the permit areas. Further access to the properties is provided by secondary one- or two-lane all-weather roads, and numerous all weather and dry weather gravel roads. The resource area can be accessed year-round, ensuring mineral test work and extraction is not limited to certain months of the year. Two rail lines (Canadian Pacific Railway and the Canadian National Railway) are present throughout the area and connect to the major centers of Edmonton and Calgary, which occur north and south of the resource area, and then to all North America.

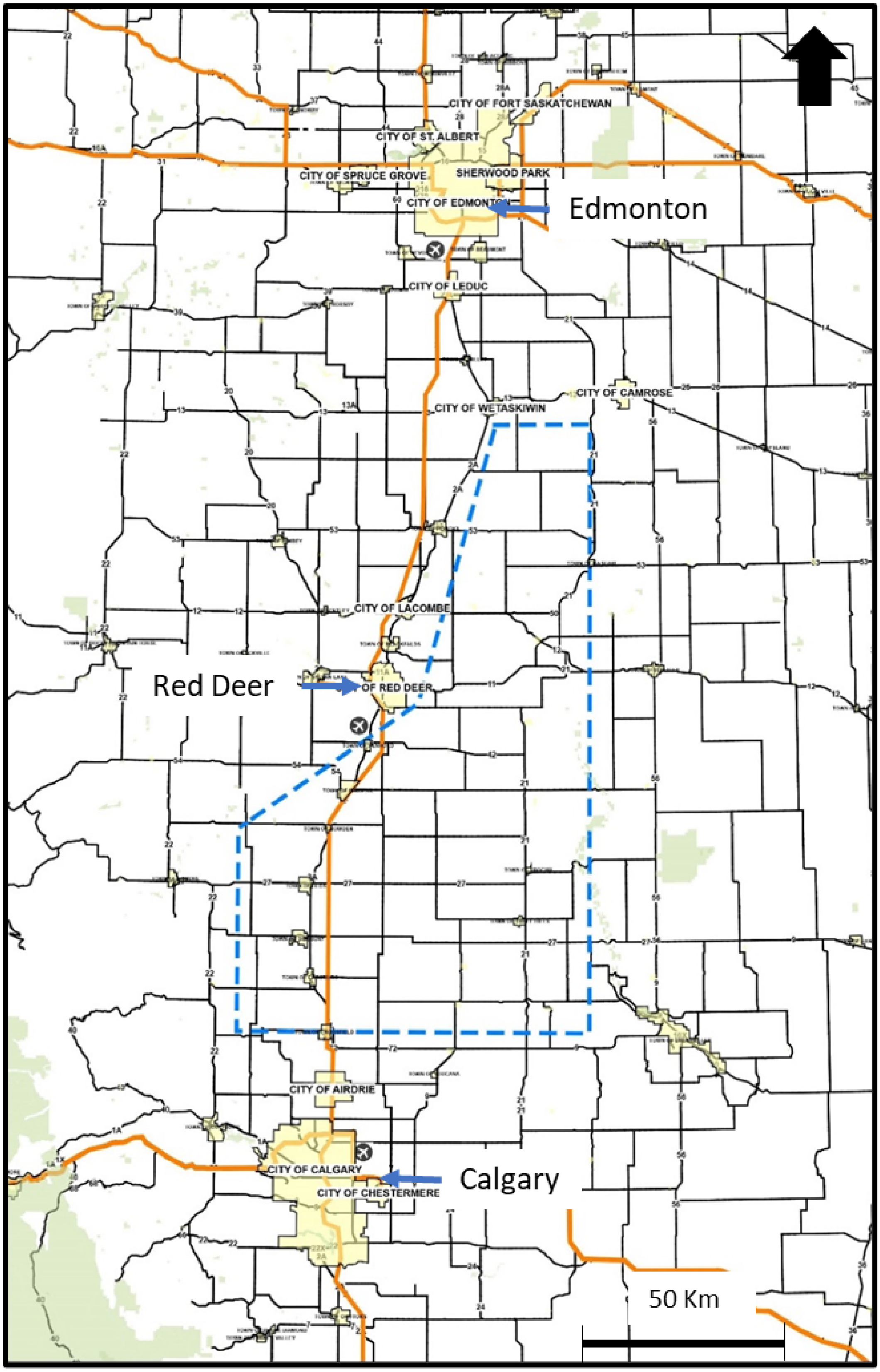

Figure 3: Infrastructure Access to Bashaw District[x]

5.2. Climate

Calgary, Alberta has a continental climate with severe winters, no dry season, warm summers and strong seasonality (Köppen-Geiger classification: Dfb). During summer, average daily high temperatures 23.2 (73.8 °F) and average daily low temperatures are 8.4°C (47.1°F). Winter temperatures have average daily highs of -2.1°C (28.2°F) during the day and average daily lows of -13.3°C (8.1°F) generally shortly after sunrise. Total annual precipitation averages 395 mm (15.6 inches). A summary of Calgary climate data for 2021, by month is shown in Figure 4. A 10-year summary of high-low-mean air temperature and mean precipitation for township 35, range 25 W4M, the center of the BD, is shown in Figure 5. As this is a reservoir that will be produced using DLE technology to extract lithium from brine, there are no climate related limitations to resource extraction, unlike the situation for salar-type deposits.

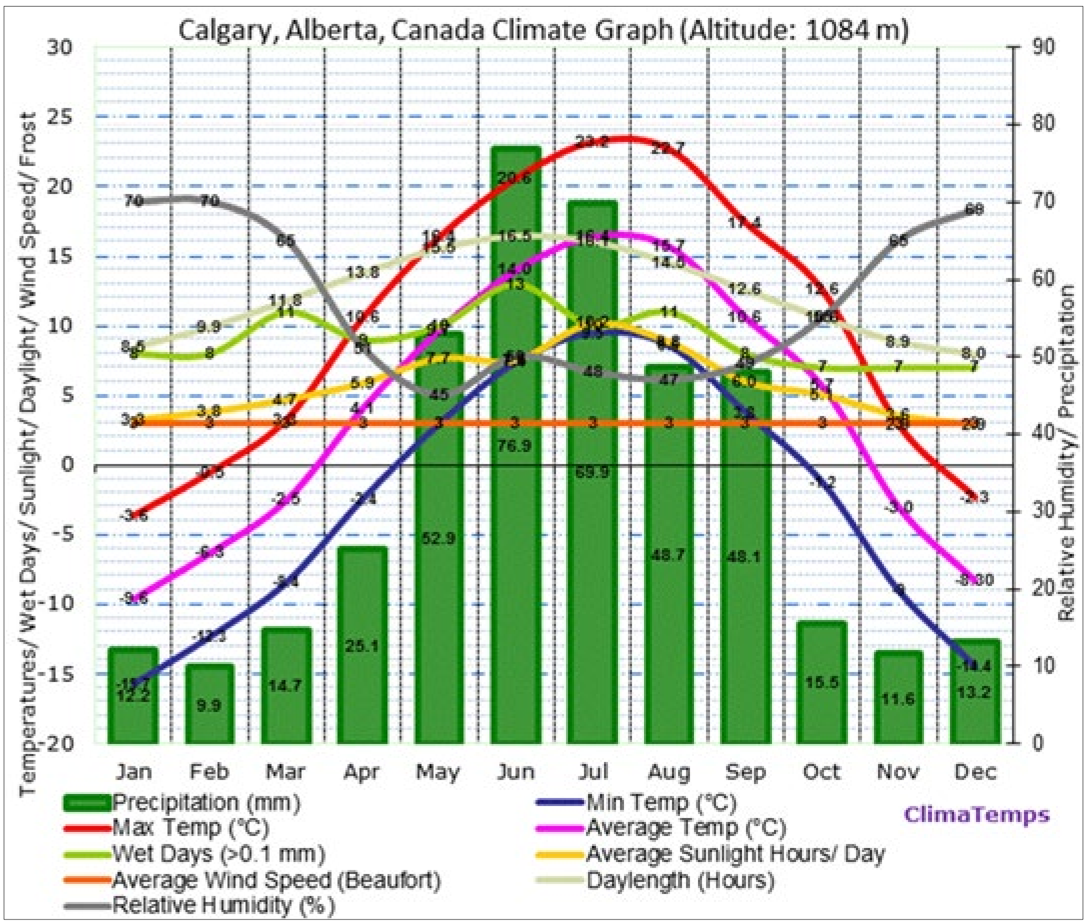

Figure 4: Summary of Monthly 2021 Climate Data for Calgary, Alberta[xi]

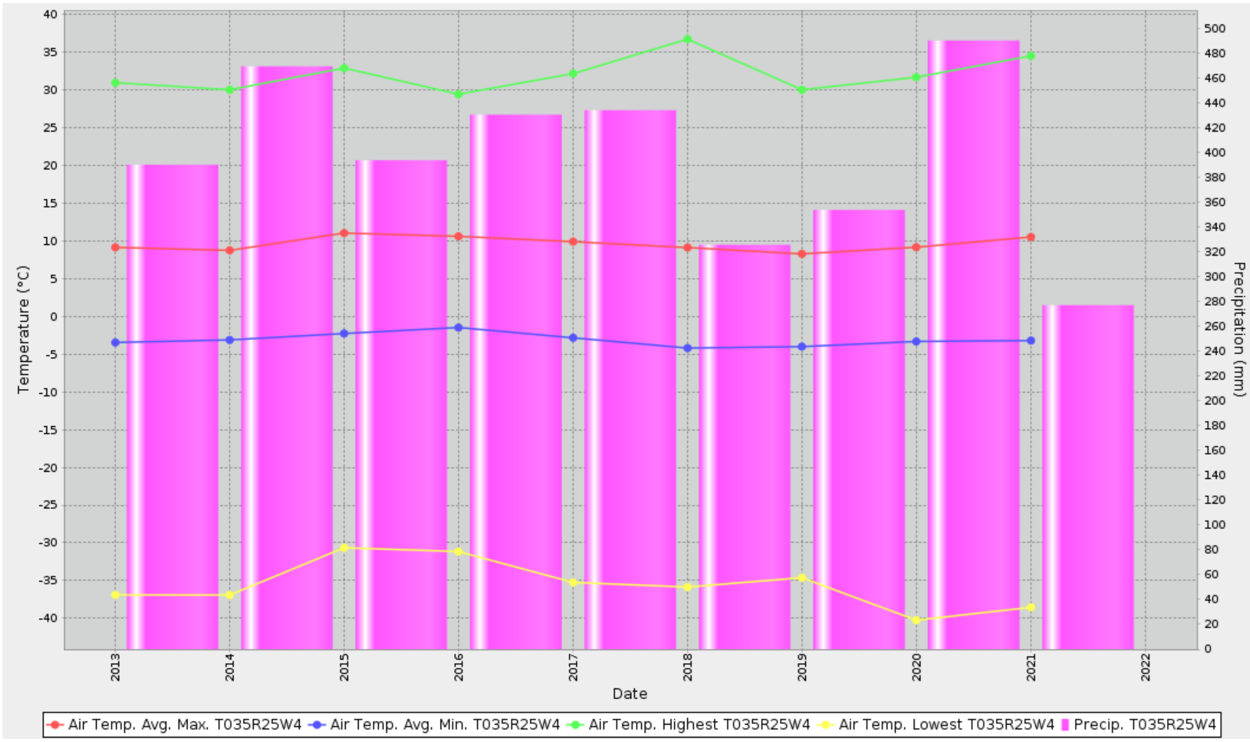

Figure 5: 10-year Temperature and Precipitation Ranges for T35N R25W (ACIS, 2022)

5.3. Local Resources

Accommodation, food, fuel, and supplies are readily obtained in the City of Red Deer and the towns of Olds, Sylvan Lake and Innisfail. Internet and phone coverage are available throughout the permit areas. Many trained workers live in the area and work in the oil and gas sector. These workers have the skills and expertise required to develop lithium from their related experience in oil and gas. Service companies, including those providing wireline services, testing, maintenance work, and drilling, all operate locally and will be capable of meeting the company's needs relating to drilling, production and construction.

5.4. Infrastructure

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

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

5.5. Physiography

The project area lies within the Southern Alberta uplands and Western Alberta plains. The dominant landform is undulating glacial till plains, with about 30 percent as hummocky, rolling, and undulating uplands. The average elevation is 750 masl but ranges from 500 masl near the Alberta–Saskatchewan border to 1,250 masl near Calgary and 700 masl near Edmonton. The Red Deer River is the dominant topographic feature; it flows south-southeast from middle of the Exshaw property to Drumheller in the in the southeast of the permit area. The region is dominantly farmland with numerous creeks and wetlands occurring throughout the property. Clusters of forested terrain are dominated by aspen, balsam poplar, lodge pole pine and white spruce. Vegetation in the wetland areas is characterized by black spruce, tamarack and mosses. The area is generally composed of farmland and prairie grasses.

6. History

E3's 2022 drill program was the first in Alberta specifically drilled to test brine for lithium concentrations. No other operator in Alberta has drilled wells solely to evaluation lithium concentrations in subsurface brines. Historical testing of lithium in water, prior to E3, was conducted as part of routine chemistry analysis by oil and gas operators in the area. This data was compiled in a comprehensive overview of the mineral potential of formation waters from across Alberta by the Government of Alberta (Hitchon et al., 1993[xii], 1995[xiii]). Subsequent collection of brine water from actively producing oil and gas wells was conducted by the AGS by Eccles and Jean (2010)[xiv] and later by Huff (2016)[xv] and was analyzed for lithium. A summary of the petroleum exploration and production and the lithium brine related geological data sourced from the petroleum industry are summarized below.

6.1. Brine and Hydrocarbon Drilling History

E3 is a leading brine-hosted mineral company in Alberta, being the first operator to drill wells solely for purposes of measuring lithium content in subsurface brines. E3 drilled two vertical wells in June and July of 2022 and acquired a third deviated well through another operator. Section 9 provides an overview of the operations and sampling procedures for each of these wells.

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

The BD contains several Leduc oil pools of note (e.g., Clive, Bashaw, Nevis, Three Hills Creek, Wimborne, Wood River, Garrington, Innisfail, Lone Pine Creek, Joffre, Swalwell, Lochend, Penhold, Duhamel and Malmo; Figure 6). A total of 13,729 wells have been drilled within the BD dating back to 1947, targeting the former mentioned pools and as exploratory wells delineating hydrocarbon potential. Of these wells, 2,398 have intercepted the Leduc formation. The Innisfail oil field along the western edge of the BD, was discovered in 1956 by Canadian Oils Ltd., and the Wimborne field along the eastern edge, was discovered by Seaboard Oil Company in 1954. The Duhamel oil field on the northern edge, was discovered in 1950 by Socony Vacuum Exploration Co., and the Swalwell field and the town of Crossfield define the southern edge of the resources area. The Swalwell was discovered in 1953 by Canadian Delhi Oil LTD. A total of 1,457 wells are classified as having produced, currently producing or injecting into the Leduc Formation.

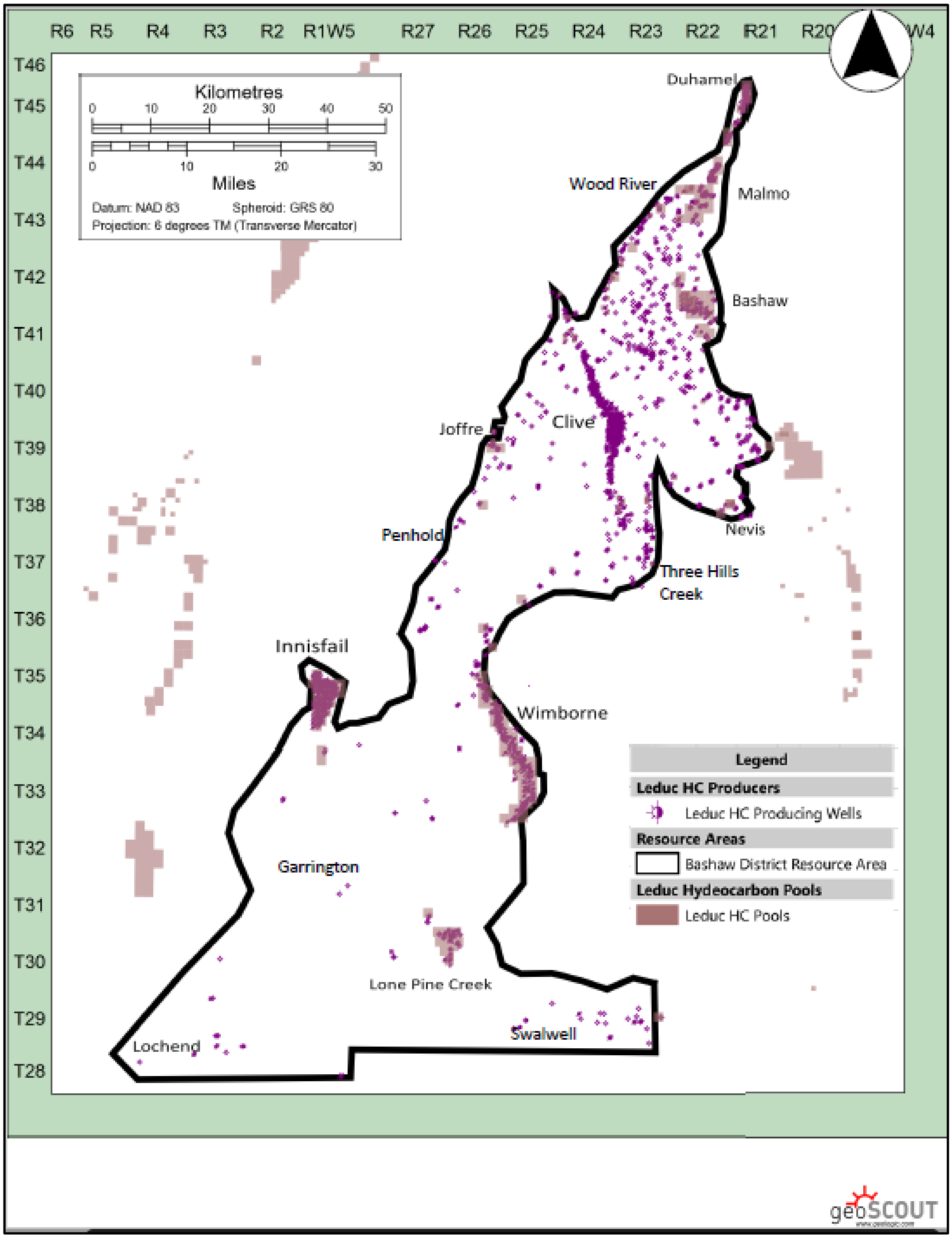

Figure 6: Location of Leduc Wells and Pools in the Bashaw District

6.2. Core Data and Historical Well Logs

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

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

The well logs available in the area are as follows:

- Gamma Ray Log: measures the radioactivity of rocks and helps determine lithology[xvi]
- Induction Log: measures formation electrical conductivity, and helps determine lithology and fluid composition[xvii]
- Density and Neutron logs: measures hydrogen concentration and electron density[xviii], and helps determine lithology and pore space in the rock
- Photoelectric logs: measures atomic weight of the rocks, and helps determine lithology

Core analysis is also routinely completed by the oil and gas industry. Standard oil and gas core analysis includes measurements of porosity and permeability. Various approaches can be taken to make these measurements (API 1998[xix]). Typically, the porosity is determined by weighing the sample, then cleaning the sample and completely flushing all the liquid out of it. Sample is then dried in an oven and weighed again after. Then either air or helium is used to measure the pore volume and porosity is calculated based on the amount of total pore volume in the rock sample. Permeability is also typically measured using air and is measured in 2 directions. One is the direction that has the maximum permeability (Kmax) and the second is measured at 90 degrees to the maximum (K90). Comparing core analysis with measurements obtained in petrophysical logs helps to validate whether the log data is reasonable. Publicly available core analysis data is available for 329 wells within the Bashaw Resource District. Distribution of the core analysis data is limited to existing hydrocarbon production wells that were drilled over the past 70 years and is mainly limited to the upper portion of the Leduc reservoir where hydrocarbons have accumulated.

6.3. Hydrocarbon Industry Drill Stem Tests

A Drill Stem Test (DST) is an oilfield test that isolates a particular range of depths in a wellbore to measure the reservoir pressure, permeability (ability to flow fluid) and fluid types present at specified depths. DSTs have been run in the vicinity of the resource areas since the 1950's.

6.4. Existing Production, Injection, and Disposal

Historical production volumes for the Cooking Lake and Leduc formations were exported from GeoLOGIC's GeoSCOUT software (GeoLOGIC Systems 2023). The reported production was queried for the BD and a buffer area around the BD, to include production from outside of the resource area that may directly affect pressures in the BD.

The BD historical production query included Townships 28 to 45 and Ranges 4W5M to 20W4M. A total of 593 production wells and 57 injection wells in the BD and buffer area had at least one day of reported rates from the Leduc formation, with no recorded data from the Cooking Lake. Within the BD, most of the liquid production is from the Innisfail, Wimborne, and Clive fields while most of the gas production is from the Nevis field (Figure 7). Most of the liquid injection is into the Wimborne, Innisfail, and Clive fields while most of the gas injection is in the Joffre field (Figure 8). The first year of reported production was 1961 and the last month of production data summarized below is January, 2023 (Figure 9; Table 2).

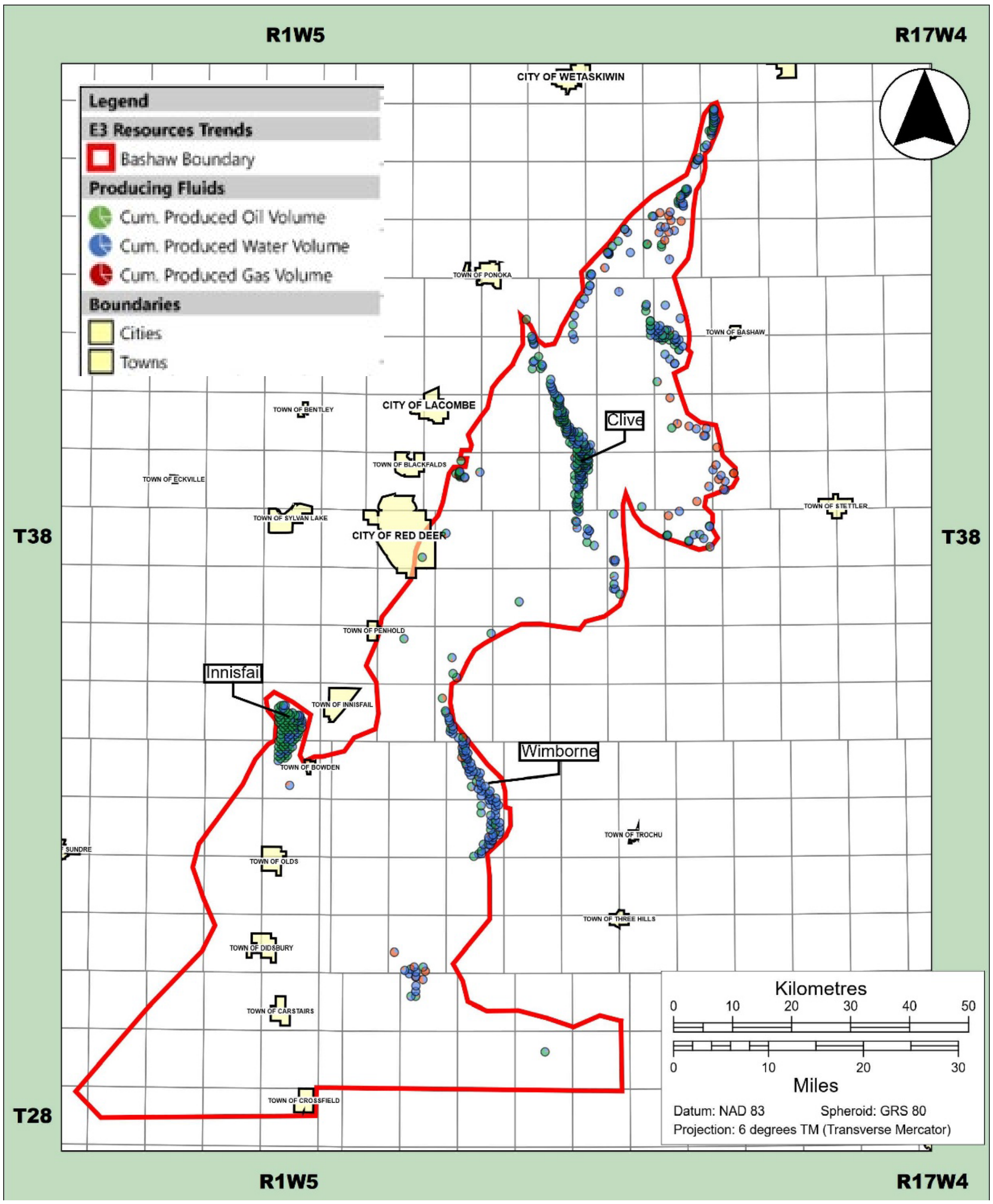

Figure 7: Production by Fluid Type from the Leduc Formation in the Bashaw District

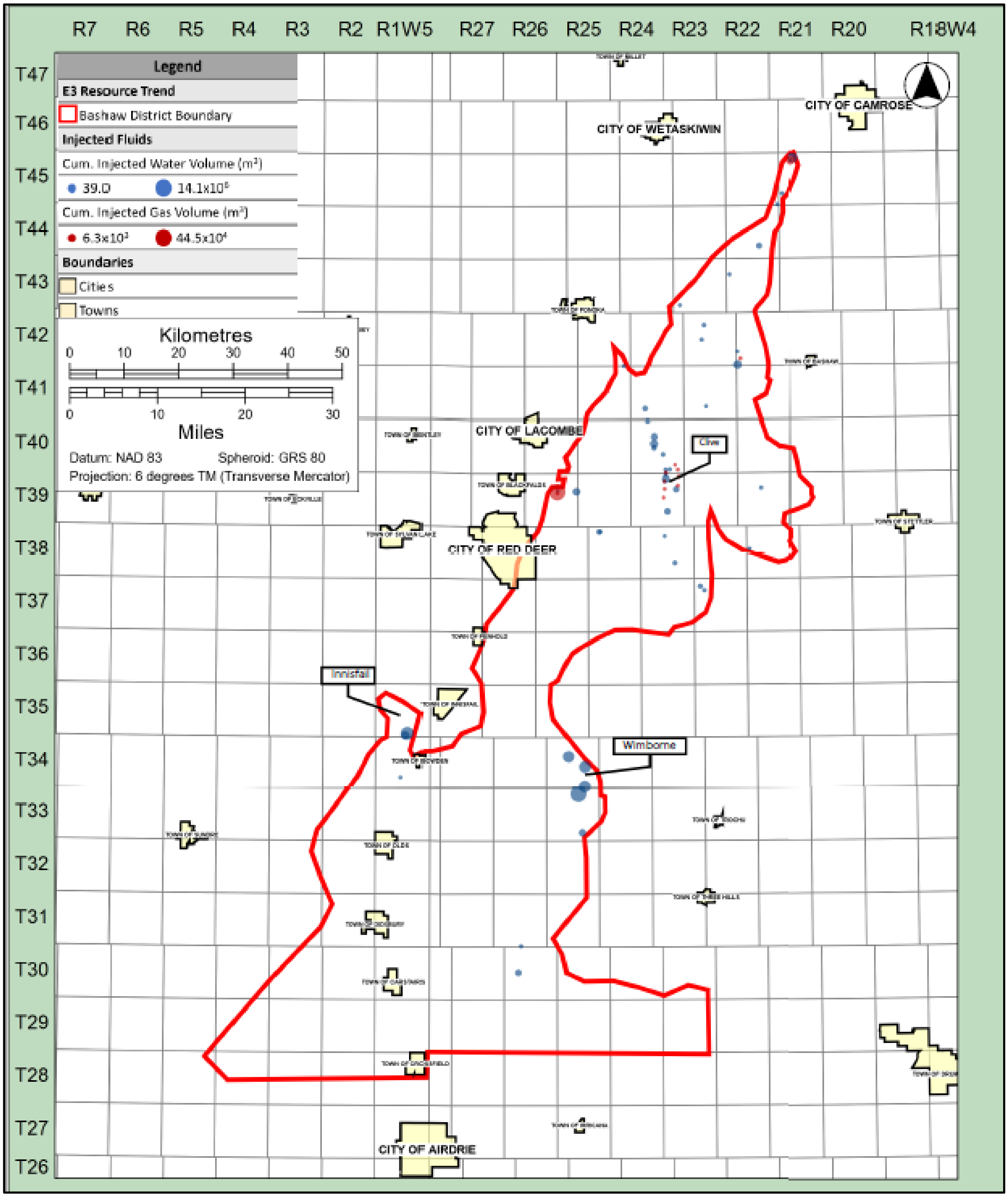

Figure 8: Cumulative Injection into the Leduc Formation in the Bashaw District

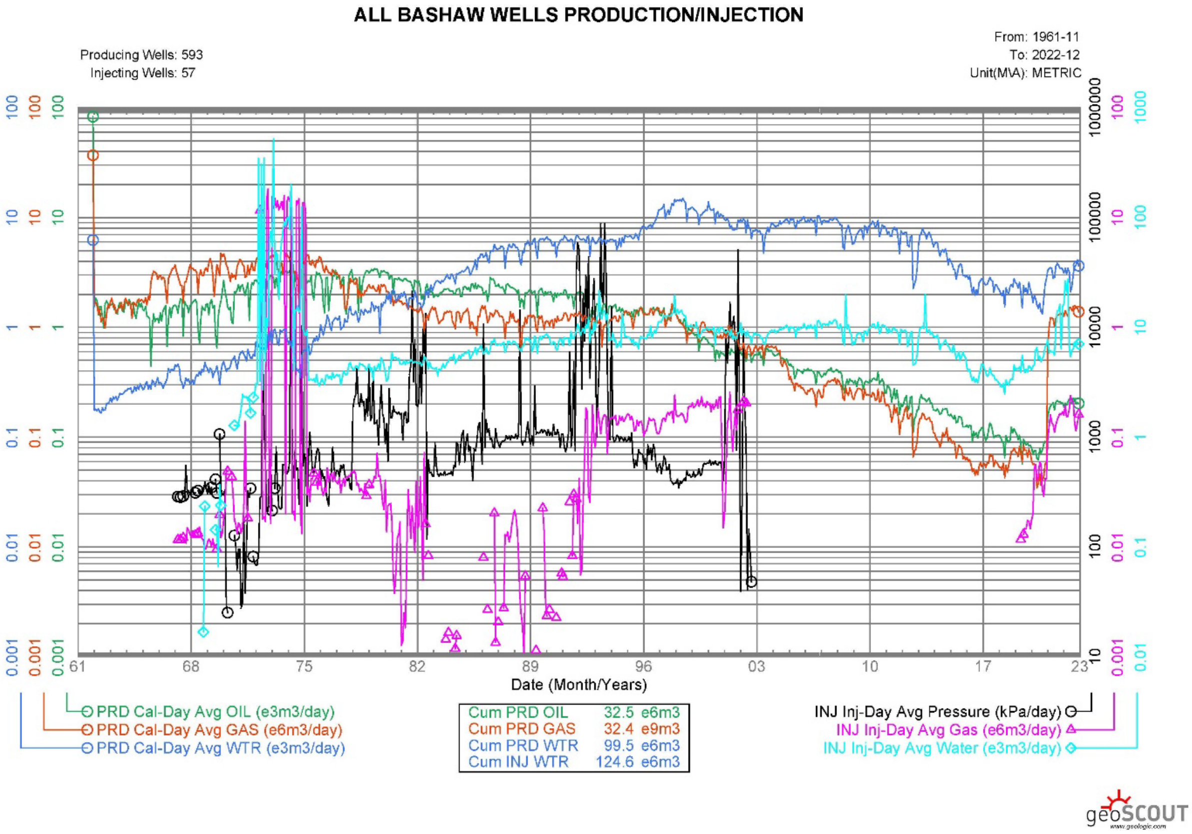

Figure 9: Production/Injection History of the Leduc Reservoir in the Bashaw District

Table 2: Cumulative Volumes in the Bashaw District

	Production [m³]	Injection [m³]
Gas	32,051,762,000	709,104,000
Condensate	179,736	-
Oil	32,411,042	-
Water	98,736,006	122,975,340

Historical volumes of gas and oil produced peaked in the 1970s and has decreased considerably since then as hydrocarbons have been depleted. By contrast, water production as a by-product increased considerably since the 1970s and plateaued in the mid-1990's and remained steady for ~ 25 years. Production plots broken down by pool can be found in Appendix B. It is important to note that the Leduc formation has sustained production and injection rates of ~1,000 m3/d for ~15 years. Peak rates reported across the BD are 2,618 m3/d for injection (100/06-02-034-26W4/00) and 2,569 m3/d for production (100/13-05-041-24W4/00). Using hydrocarbon production and injection data to show producibility/injectivity of the Leduc reservoir helps to validate that the Leduc is a reasonable prospect for eventual economic extraction of lithium brine using production wells. The long and sustained production history from the hydrocarbon window with a considerable amount of accompanying water shows that water can be pumped to surface for use with DLE technology and re-injected back to where it was produced from.

6.5. Historical and Publicly Available Lithium Data

The first comprehensive overview of the mineral potential of formation waters from across Alberta was compiled by the Government of Alberta (Hitchon et al., 1993[vii], 1995[viii]). 'Formation water' is used as a generic term to describe all water that naturally occurs in pores of a rock. Formation water is currently being produced as a waste by-product associated with petroleum and natural gas from existing wells. Pressure loss in the reservoir is being mitigated through re-injection of fluid from produced wells and possibly has included waters from other pools and other zones, as well as fresh water.

Hitchon et al. (1993[vii], 1995[viii]) compiled nearly 130,000 analyses of formation water from various stratigraphic ages across Alberta. The data was derived from numerous sources including Alberta Energy Regulator ("AER") submissions for drilling conducted by the petroleum industry and various Government of Alberta reports (e.g., Hitchon et al., 1971[xx]; 1989[xxi]; Connolly et al., 1990 a,b and unpublished analytical data collected by the Government of Alberta[xxii]) (Figure 10).

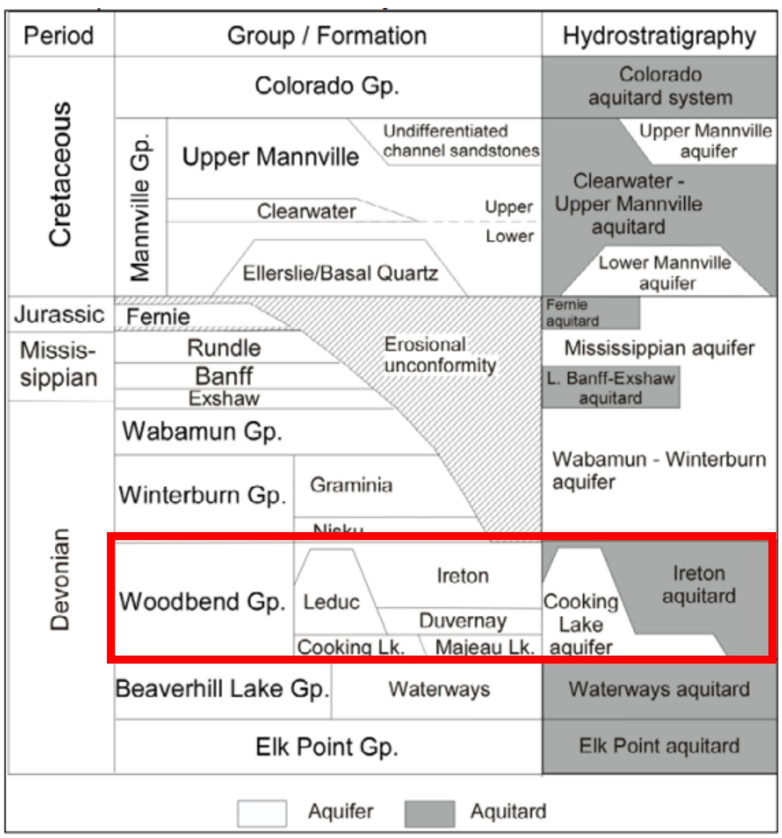

Figure 10: Regional Stratigraphy and Hydrostratigraphy of Alberta (From Lawton and Sodgar, 2011)[xxiii]

The method for defining geographic areas with elements of possible economic interest in formation water was defined by Hitchon (1984)[xxiv] and Hitchon et al. (1995)[xxv]. For each element studied (e.g., calcium, magnesium, potassium, lithium, bromine and iodine), a ‘detailed exploration threshold value’ was determined by studying the concentrations in economically producing fields as defined in Hitchon (1984)[xix] and Hitchon et al. (1995)[xxii]. Additionally, a lower ‘regional exploration threshold value’ was defined to allow for contouring and extrapolation of data to undrilled areas. For example, the regional exploration threshold value for Li was considered to be 50 ppm and the detailed exploration threshold value was defined as 75 ppm (Hitchon et al., 1995)[xx]. At the provincial scale, Hitchon et al. (1995)[xxii] showed that lithium was analyzed and reported in 708 formation water analyses (out of the 130,000 total analyses examined). Of the 708 analyses: 96 analyses yielded Li concentrations above the ‘regional threshold value’ (greater than 50 ppm); and 47 analyses yielded Li concentrations above the ‘detailed threshold value’ of 75 ppm. Significantly, Hitchon et al. (1993[vii], 1995[viii]) showed the highest concentrations of Li in formation water – up to 140 mg/L Li – occurred within Middle to Late Devonian reservoirs associated with the Beaverhill Lake Group (Swan Hills Formation), Woodbend Group (Leduc Formation), Winterburn Group (Nisku Formation) and Wabamun Formation.

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

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

From this historical reported dataset, 19 samples were taken from the BD, from the Winterburn Group (Nisku Formation) and Woodbend Group (Leduc Formation). The lithium concentrations range from 60 mg/L to 135 mg/L and have a mean of 77 mg/L. E3 was unable to return to these exact locations for resampling because they have since been suspended or abandoned. Therefore, this historical data has not explicitly utilized in E3’s resource estimate but has been used to inform E3’s understanding the continuity of lithium grade in the Leduc.

7. Geological Setting and Mineralization

7.1. Data and Methods

Data sources to evaluate the geological setting and mineralization were mostly derived from historical, publicly available oil and gas datasets. As discussed in Section 6 above, these data sets were evaluated for quality and are summarized in Table 3.

Table 3: Summary of Oil and Gas Relevant Data Sources

Data Type	QA/QC Criteria	Data Utilization
E3’s 2022 Flow Test	• Consistent flow rates monitored in the field during test and stable gas production	• Pressure validation • Brine analysis: lithium concentrations

	• Consistent pressure data collection (build-up, fall-off) • Pressure derivative analysis	• Permeability estimation • Flow system continuity
E3's 2022 Evaluation Well Program	• Sufficient depth • Core recovery and quality • Geophysical well log QA/QC (see below) • Field monitored water chemistry parameters within specified thresholds	• Core analysis: total and effective porosity; permeability measurements; facies descriptions • Downhole wireline logs: lithology; total and effective porosity • Brine analysis: lithium concentrations
Well logs	• Logging completed by registered oilfield logging company with standards of practice and QA/QC procedures	• Geologic mapping (stratigraphic & structural) • Formation thickness (isopach) • Fluid contacts (oil/gas; oil/water)
Well logs penetrating through both the Leduc and the Cooking Lake formations were used to determine the top and bottom of the formations and, the lateral extent of the Leduc over top of the Cooking Lake Platform. After formation tops were selected, well logs were then used to determine fluid contacts (oil/gas, oil/water) and reservoir parameters within the Leduc. Neutron-density logs were utilized where available, as they are a more reliable log type. In an effort to leverage all available data, sonic logs were utilized where they were the only logs available. There are 2397 well logs in the BD which penetrate the Leduc reservoir, and 101 well logs that are drilled to the Cooking Lake platform (or deeper). Within this dataset, there are also 329 wells with core porosity and permeability measurements in the Leduc formation, and 57 wells where E3 completed enhanced petrophysical modeling to normalize the porosity curves in the wireline logs and correlate the curves to the core porosity.		
Petrophysical analysis [57 wells]	• Complete wireline data set	• Porosity [total and effective] • Permeability [vertical & horizontal] • Fracture identification • Evaporite identification • Fluid saturations
A petrophysical model was generated using 57 Log ASCII Standard (LAS[xxvi]) curves over the Bashaw area. Linear regression analysis was used to derive permeability (outlined in Section 14) as it can identify hydraulic flow units and correlates well with core permeability results. Effective porosity estimated from petrophysics was modelled using a shale volume approach.		
Core data [336 wells]	• Sufficient depth • Sufficient recovery to visibly interpret core • Public core analysis	• Facies characterization (porosity [total]; permeability [vertical & horizontal]) • Net to gross ratio

<table>
<tr><td></td><td></td><td>• Guide log interpretation in areas without core</td></tr>
<tr><td colspan="3">Core was described and analyzed by E3 (41 cores). Publicly available core analysis was leveraged for effective porosity, which was measured using helium injection and Boyle's Law[xxvii] and permeability, and core was calibrated to petrophysical log data.</td></tr>
<tr><td>Drill Stem Tests</td><td>• Sufficient depth
• Copies of original DST available
• Liquid fluid inflow
• Minor amounts to no gas production
• Multiple build-ups (2nd Horner Extrapolation to cross-check validity)</td><td>• Reservoir pressure
• Formation permeability [horizontal]</td></tr>
<tr><td colspan="3">Data collected during DSTs are compiled by the Government of Alberta and were accessed through third party software (GeoSCOUT 2023). DST data was reviewed to determine representative Leduc reservoir pressure and permeability in the resource areas, following a quality assurance (QA) program that eliminated suspect or erroneous data.

After completing the QA program, a pressure data set of 33 DSTs within the BD with pressure measurements considered representative of the Leduc reservoir pressure. The resulting data set consisted of 30 pressure measurements in the Leduc Formation and 3 pressure measurements in the Cooking Lake Formation. These measurements were distributed throughout the resource area and were measured between 1957 and 1980. These pressure measurements were used to estimate the current day reservoir pressure and to contribute to the characterization of the hydraulic continuity of the resource brine.</td></tr>
<tr><td>Seismic (6 regional lines ~120 km)</td><td>• Data was of reasonable vintage to be useful for interpretation
• Data was high enough quality/resolution</td><td>• Qualitative porosity indicator
• Validates reservoir thickness over areas that have no wireline logs or other geological data</td></tr>
<tr><td colspan="3">Seismic data is data collected by measuring rock properties using physics principles. It is based on the theory of elasticity and tries to deduce elastic properties of materials by measuring their response to seismic waves. Use of seismic can help to measure rock properties (such as the thickness of the reservoir and the structure of the reservoir, and porosity). It is useful as the seismic lines are continuous over areas where there is no well data and can be used to interpret areas where the wireline and drilling data are sparse/not present.</td></tr>
</table>

7.2. Geological Setting

The BD is in the southwestern part of the Western Canada Sedimentary Basin (WCSB). In this area, the Upper Devonian (Frasnian) sediments of the Woodbend Group were deposited in a shallow tropical inland sea. The sea was bounded by the emergent Peace River Arch to the northwest and by the West Alberta Ridge to the southwest, creating a barrier between the sea and the open ancestral Pacific to the west (Potma et al. 2001[ii]). It is here that the flooded carbonate platform of the Cooking Lake provided relative structural highs and a favorable environment for the growth of the prolific reefal buildups of the Leduc Formation.

The BD covers a portion of the Wimborne-Bashaw trend, comprising Townships 28 to 45 and Ranges 21 to 28 West of the 4th Meridian, to Range 5 West of the 5th (Figure 11).

A total of 101 wells in and around the resource areas penetrate the full stratigraphic section of the Leduc reservoir and Cooking Lake platform. 2397 wells penetrate the top of the Leduc reservoir and were not drilled deep enough to intersect the lower Cooking Lake formation. This is typical of wells drilled for the purpose of hydrocarbon production in the Leduc specifically.

The edge of the Leduc carbonate complex is defined as the point at which the Leduc carbonate production factory transitions to basinal slope deposits (zero-edge). This edge differentiates the high porosity reefal buildups of the Leduc from the surrounding low porosity carbonate muds and shales of the deep-water basin sediments occurring in the Ireton and Duvernay Formations. The zero-edge, the basis for the BD, was defined primarily using well data. In the absence of well data, existing industry-standard Leduc edge interpretations were consulted (Mossop et. al., 1994[xxxii]; Potma et al. 2001[ii], GeoScout Devonian Subcrop, 2022 GeoScout Devonian Subcrop, 2022[xxviii]). The local and regional geological context was also taken into consideration when making interpretations.

The Leduc sits atop the limestones and dolomites of the regionally extensive Cooking Lake, which is differentiated from the Leduc by the presence of a regional argillaceous (shale) zone (Figure 12). This argillaceous zone is not present in all wells, and in those cases the top of the Cooking Lake was defined based on offsetting wells using relative thicknesses and geological context. Generally, the Cooking Lake has a slightly higher gamma ray response than the Leduc. The base of the Cooking Lake was chosen where the more argillaceous Beaverhill Lake Group became evident.

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

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

Table 4: Cooking Lake Permeability and Hydraulic Conductivity

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

Well 100/04-10-033-28W4/00 (starred location on Figure 11), presents a type log suite of the interior lagoonal facies of the Leduc reef (Figure 12). The top and base of the Leduc formation are picked from wireline log suites across the BD. The Ireton formation overlies the Leduc and can be comprised of mudstone to argillaceous dolostone, which are characterized by a much higher radioactivity than the Leduc. This type of Ireton lithology is associated with a higher response in the gamma ray log (+30 API), compared to the carbonate rich Leduc and Cooking Lake Platform with very low radioactivity, and have API's of less than 15. In some locations, the Ireton formation is comprised of calcareous shale, and the contrast in gamma ray response between the Ireton and underlying Leduc can be more challenging to define on logs. Core to log calibrations have assisted in correctly picking the base Ireton when its lithology is more calcareous.

Other logs presented in Figure 12, showcase interpretations of rock properties, specific to the Leduc reservoir. The photoelectric factor log shows the shift close to the base of the Leduc, where limestone-which has a reading of ~5.08 Pe (Schlumberger 1989[xxx]) is the more dominant lithology. The neutron density, spontaneous potential and resistivity logs, all show fluctuations that are indicative of the porosity and permeabilities across the reservoir, and as well the high saline conductive brine that occupies the pore space.

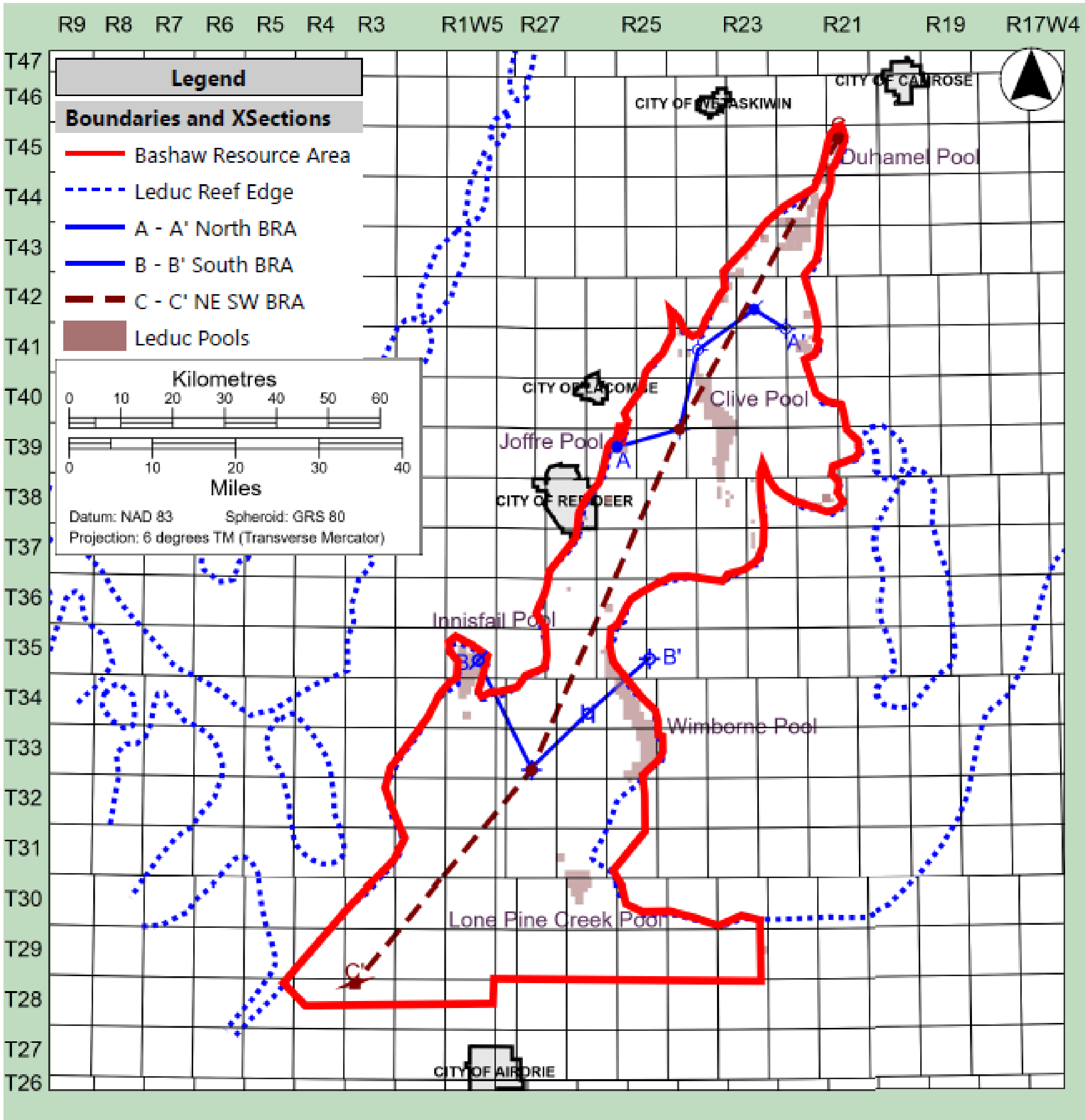

Figure 11: Area Map of Bashaw District and the Regional Leduc Edge (E3, 2022)

Cross Section Reference Lines A-A' (Figure 13), B-B' (Figure 14), and C-C' (Figure 15)

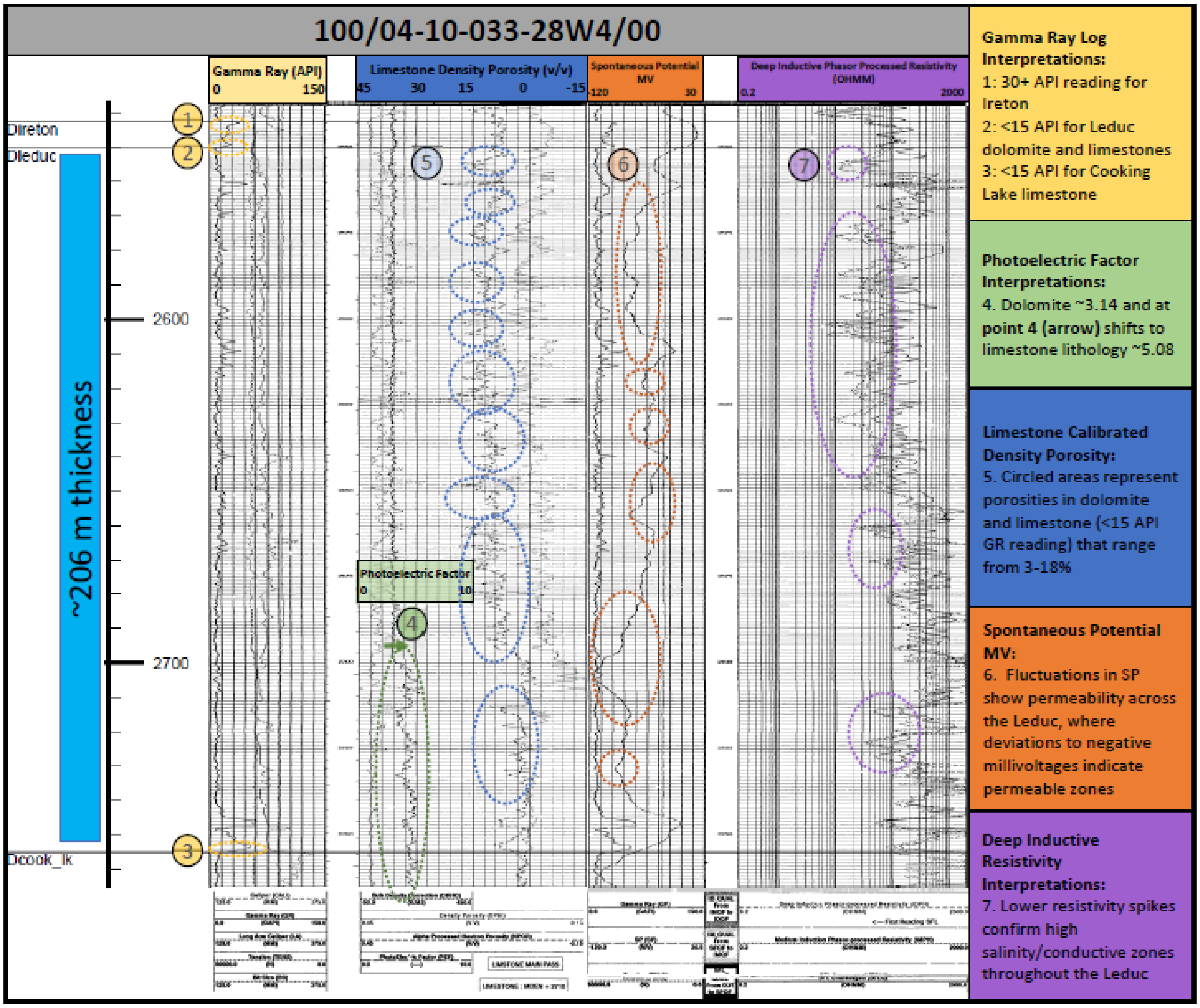

Figure 12: Interior Lagoonal Facies Type Well (100/04-10-033-28W4/00)

The type well shows a log suite representative of criteria and rock properties interpreted from the logs that are used for picking the top and base of the Leduc reservoir.

Cross-Section A-A’ (Figure 13) in the Exshaw sub-project area demonstrates the reservoir continuity across the north BD area Leduc platform. It highlights the relative thickness of the interior lagoonal facies of the Leduc reef complex as well as the corresponding hydrocarbon pools.

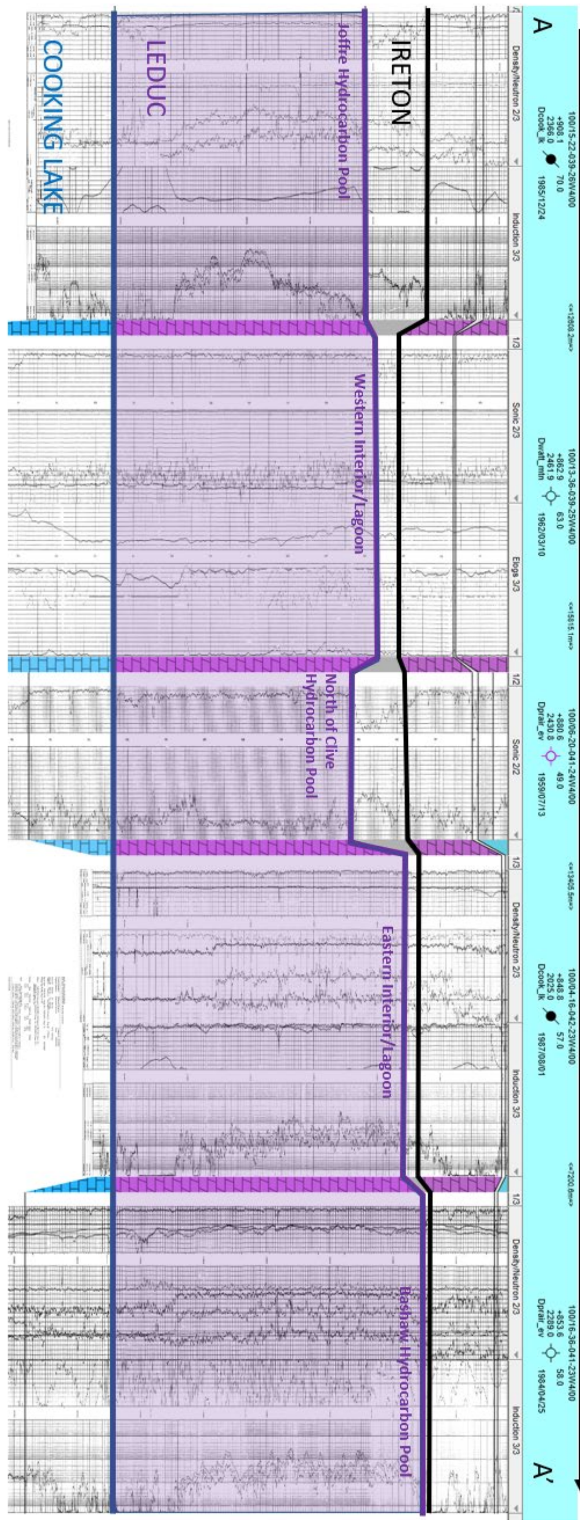

Figure 13: Stratigraphic Cross Section A-A’, North Bashaw District, Cooking Lake Datum (E3, 2022)

Cross section B-B’ (Figure 14) in the Clearwater sub-project area demonstrates the resource brine continuity across the south BD Leduc platform. It highlights the relative thickness of the Leduc hydrocarbon pools at Innisfail and Wimborne to the interior lagoon and the basinal Duvernay mudstones and finer-grained carbonates along on the east side.

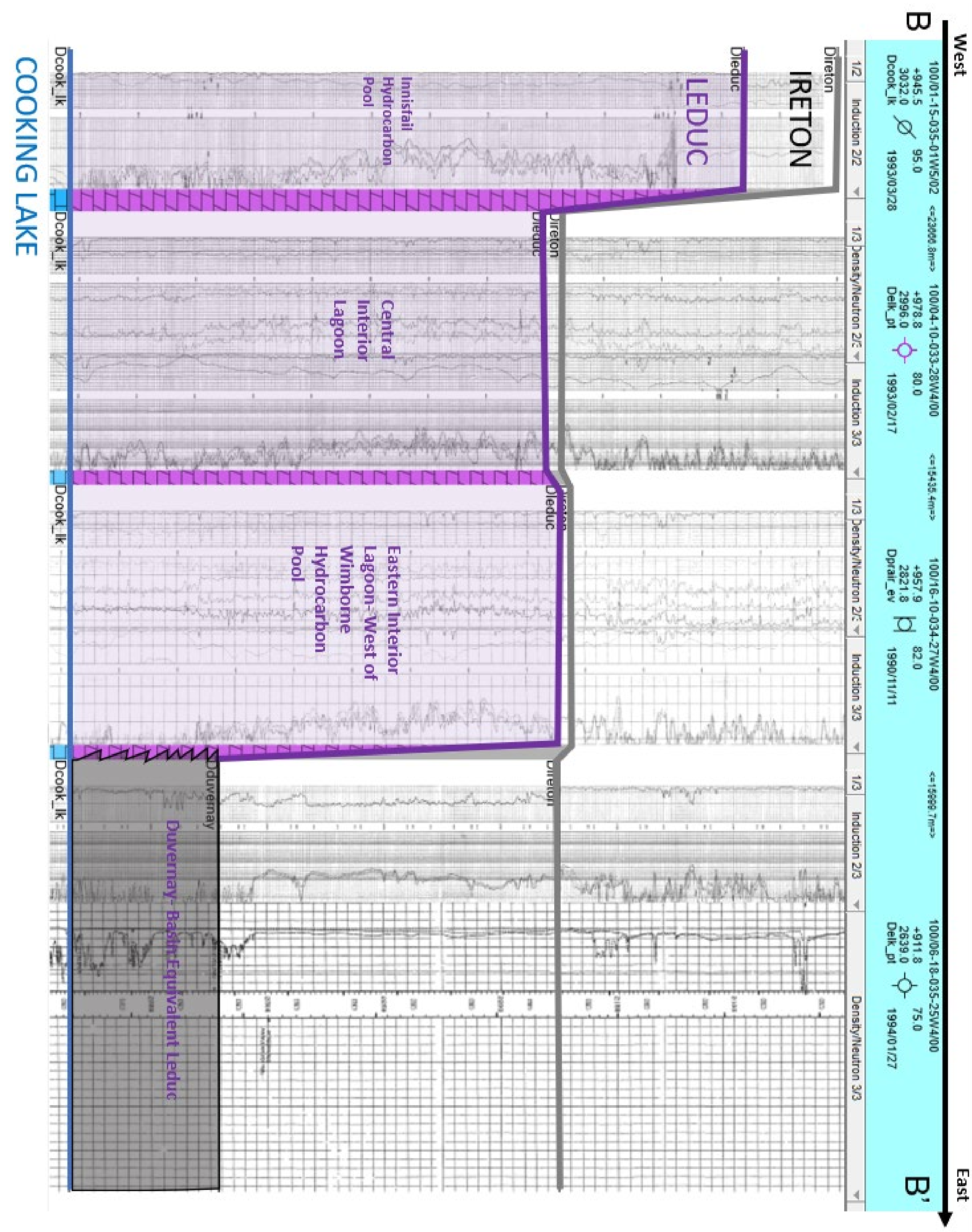

Figure 14: Stratigraphic Cross Section B-B’, South Bashaw District, Cooking Lake Datum (E3, 2022)

Cross section C-C’ (Figure 15) highlights the resource brine continuity across a northeast to southwest trend of the BD Leduc reef. It showcases a thicker Leduc reef complex at the northeastern tip (Duhamel hydrocarbon pool), similar thicknesses of 200+metres in both reef interior wells (100/13-36-039-25W4/00 and 100/04-10-033-28W4/00), and a thickening of the reservoir in the southwest portion of the BD.

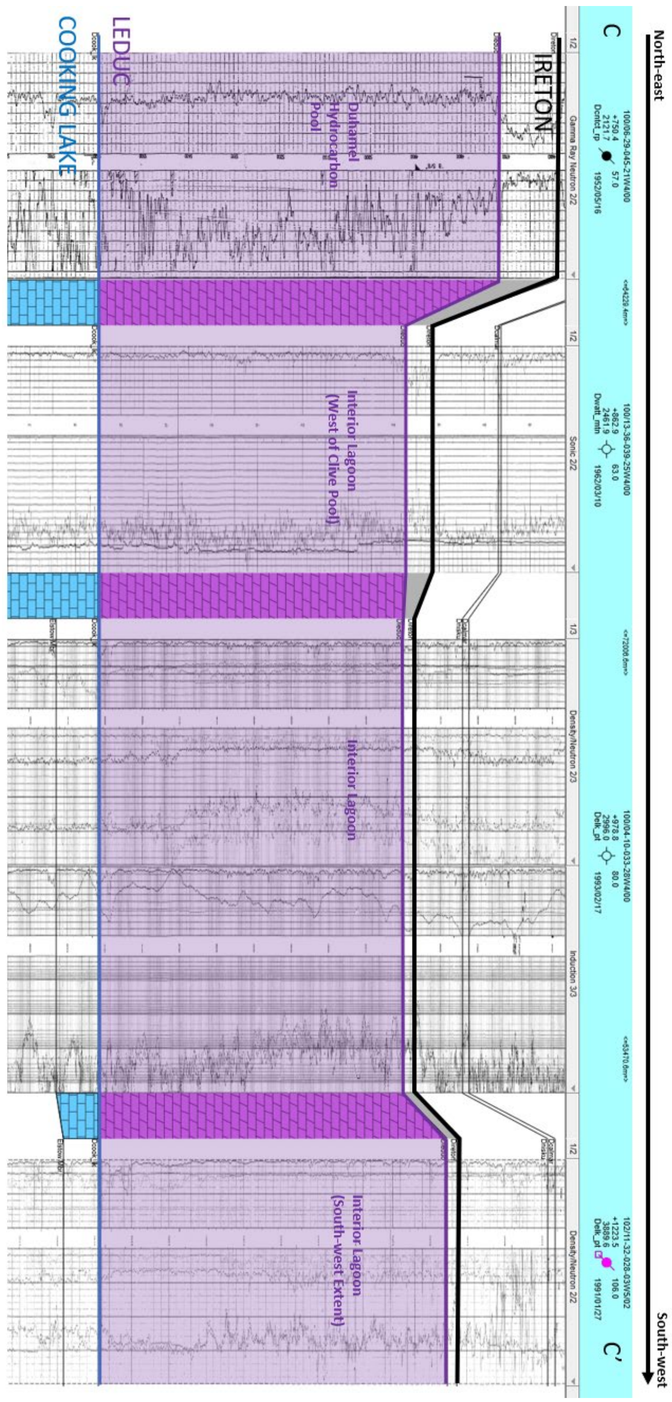

Figure 15: Stratigraphic Cross Section C-C’, Northeast to Southwest Trend Across the Bashaw District, Cooking Lake Datum (E3, 2022)

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

Schematic representations of current relationship of the geology, structure and hydrocarbon pools in the BD can be seen in Figure 16 (to scale with vertical exaggeration).

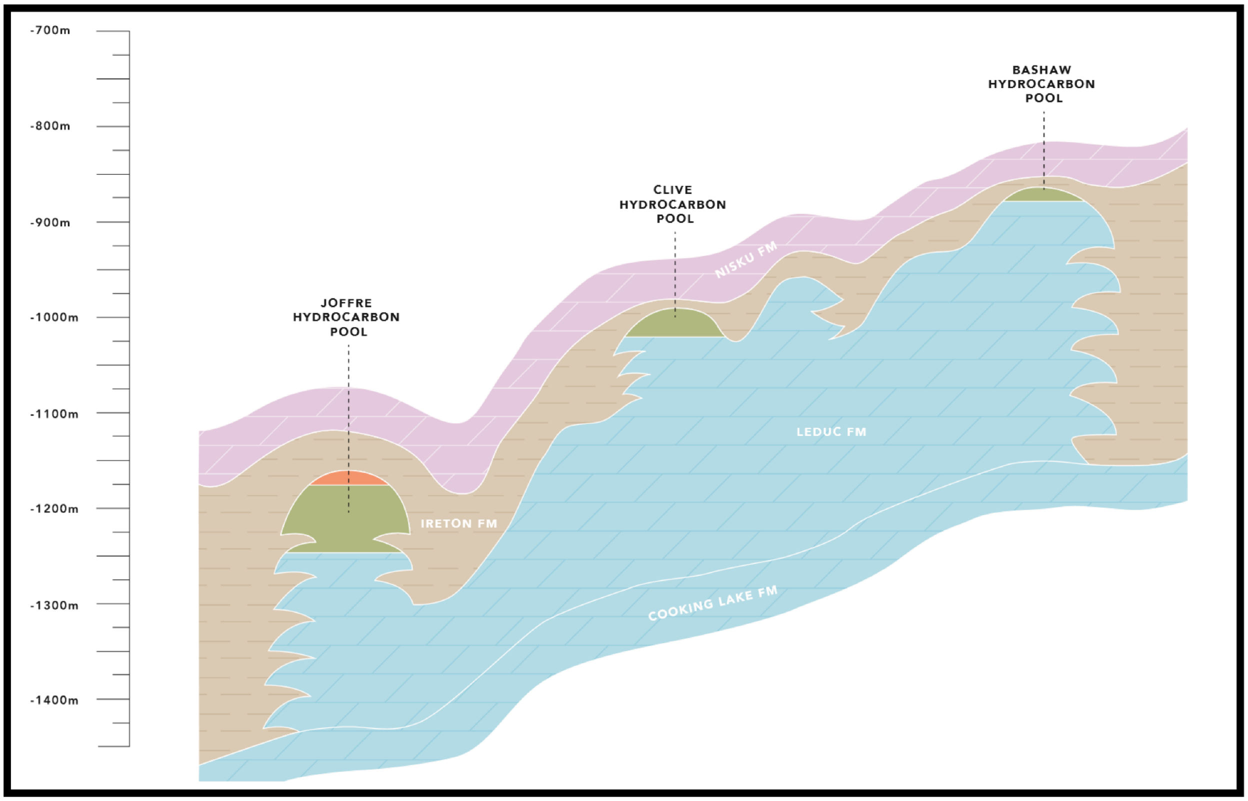

Figure 16: Schematic Representation of the Bashaw District (E3, 2018)

The Leduc and Cooking Lake were partially to completely replaced by dolomite (Drivet and Mountjoy, 1997[xxxi]; Mountjoy et al. 1997[xxxii]; Mountjoy et al. 1996[xxxiii]; Mountjoy et al. 1995a[xxxiv]; 1995b[xxxv]). Dolomitization is the chemical process by which limestone ($CaCO_3$) is converted to dolostone ($CaMg(CO_3)_2$) through the dissolution of calcium carbonate and the precipitation of dolomite ((James and Jones, 2015[xxxvi]; American Association of Petroleum Geologists, 2017[xxxvii]). The smaller ionic radius of magnesium, compared to calcium, creates a volume reduction when magnesium replaces a calcium to form dolomite. This volume reduction can create enhanced porosity and permeability in the reservoir (James and Jones, 2015; Reeder, 1983[xxxviii]).

There are many possible mechanisms theorized as to the source of dolomitizing Mg-rich fluids and the method for their transport into the Leduc reefs in the southern Alberta basin, but few published studies specifically for the BD area (Atchley et al. 2006[xxxix]; Amthor et al., 1993[xl]; Machel et. al., 2002[xli]). Across the BD dolomitization of the Leduc generally enhances the porosity and permeability of the reservoir; section 14.6 Reservoir Porosity, discusses this concept in more detail.

Speculation exists as to the source of the lithium for the lithium-enriched brines of the Woodbend and Winterburn groups in WCSB, but the source is ultimately unknown (Eccles et. al, 2012[xlii]). For the Leduc and Nisku system in southern Alberta, Huff (2016)[xi] proposed a source involving lithium concentrated Devonian evaporites to the west and upward movement of Li-enriched brine into the Leduc and Nisku carbonates during later mountain building. Regardless of the source of the lithium, the theories suggest that the lithium enrichment into the brine occurred prior to the brine migration into the Woodbend group, which supports the observed data of low variability in lithium concentrations across the BD.

7.3. Precambrian Basement

The BD lies in the southern portion of the WCSB, which forms a wedge of Phanerozoic strata overlying the Precambrian basement. The basement underlying the BD is predominantly Lacombe Domain with the southeastern portion of the property on the Hearn Terrane (Pană, 2003[xliii]). The Hearn Terrane is part of the Churchill Province and formed approximately 2.6 to 2.8 billion years ago (Ross et al., 1991[xliv]).

7.4. Phanerozoic Strata

Refer to the stratigraphic column (Figure 10) as a guide for understanding the rock units described below.

A thick sequence of Paleocene and Cretaceous clastic rocks and Mississippian to Devonian carbonate, sandstone and salt overlie the basement (e.g., Green et al., 1970[xlv]; Glass, 1990[xlvi]; Mossop and Shetsen, 1994[xxxii]). At the base of the Beaverhill Lake Group, the Elk Point Group is comprised of restricted marine carbonate and evaporite that gradationally overlies the Watt Mountain Formation (Mossop and Shetsen, 1994[xxxii]). The Upper Elk Point, including the Ft. Vermillion, Muskeg and Watt Mountain formations represent a seal (Hitchon, 1990[xviii]).

The Upper Devonian Woodbend Group conformably overlies the Beaverhill Lake Group. The Woodbend Group is dominated by basin siltstone, shale and carbonate of the Majeau Lake and Cooking Lake. The Duvernay and Ireton formations surround and cap the Leduc reef complexes. The Leduc reefs are characterized by multiple cycles of reef growth including backstepping reef complexes and isolated reefs (Mossop and Shetsen, 1994[xxxii]). The Duvernay Formation is composed of dark bituminous shale and limestone which contain and preserve a large accumulation of organic carbon thought to be the source for most of the conventional hydrocarbons in the upper Devonian in Alberta. The Ireton Formation caps the Leduc reefs and was deposited by increased fine grained sedimentation into the region (Mossop and Shetsen, 1994[xxxii]). The Ireton Formation is a seal that forms an impermeable cap rock over the Leduc reefs (Hitchon et al., 1995[viii]). The Camrose Member represents the only significant carbonate deposition during the Ireton cycles of basin-filling shale (Stoakes, 1980[xlvii]).

The Woodbend Group is conformably overlain by the Winterburn and Wabamun Groups of upper Devonian age. In the BD, the Winterburn thickness in south-central Alberta is available from the logs of holes drilled for petroleum and is composed of shale and argillaceous limestone. The Wabamun Group is composed of buff to brown massive limestone interbedded with finely crystalline dolomite at the base.

These two Groups comprise the Wabamun-Winterburn reservoir system from which a few Li concentration analyses have been obtained (Hitchon et al., 1995 [viii]).

The Wabamun Group is unconformably overlain by the Lower Carboniferous Exshaw shale. The Exshaw shale is overlain by the Banff Group, which is composed of a medium to light olive grey limestone with subordinate fine-grained siliciclastics, marlstone and dolostone overlying a basal shale, siltstone and sandstone unit (Mossop and Shetsen, 1994[xxxii]). The Rundle Group conformably overlies the Banff Group and is composed of cyclic dolostone and limestone with subordinate shale. Permian strata in the area are thin. The Permian Belloy Group unconformably overlies the Rundle Group and is unconformably overlain by the Triassic Montney Formation. It is composed of shelf sand and carbonate (Mossop and Shetsen, 1994[xxxii]).

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

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

7.5. Quaternary Geology

During the Pleistocene, multiple southerly glacial advances of the Laurentide Ice Sheet across the region resulted in the deposition of ground moraine and associated sediments in south-central Alberta (Dufresne et al., 1996[xlviii]). The majority of the BD is covered by drift of variable thickness, ranging from a discontinuous veneer to just over 15 m (Pawlowicz and Fenton, 1995a, b[xlix]). Bedrock may be exposed locally, in areas of higher topographic relief or in river and stream cuts. The advance of glacial ice may have resulted in the erosion of the underlying substrate and modification of bedrock topography. Limited general information regarding bedrock topography and drift thickness in south-central Alberta is available from the logs of holes drilled for petroleum, coal or groundwater exploration and from regional government (Alberta Geological Survey) research compilations (Mossop and Shetsen, 1994[xxxii]; Pawlowicz and Fenton, 1995a, b[xxxix]). Glacial ice is believed to have receded from the area between 15,000 and 10,000 years ago.

7.6. Structural History

The BD permits are situated east of the Rocky Mountains and are not within the deformed area. An extensive study by Edwards et. al. (1998[l], 1999[li]) utilizing aeromagnetic data, gravity data, and lineament analysis indicates that deep-seated faulting related to the Precambrian basement and the Snowbird Tectonic Zone appear to have at least partial control on the distribution of reefs and some of the oil fields in the area. Many of the Devonian reef complexes in the permit area are underlain by or are proximal to basement faults. This would imply that these deep-seated faults were active around the time of reef deposition.

7.7. Leduc Lithostratigraphic Facies

The Leduc reef complex lithology across the BD, data for which is biased to the upper section (where most of the cores intersect), showcase fully dolomitized lithologies, therefore original fabric and skeletal, and or non-skeletal grain makeup can be indistinguishable at best. Photoelectric factor (PEF) well logs that intersect the entirety of the Leduc formation, indicate limestone shifts (Figure 12) a change from dolomite ~3.14 to limestone ~5.08 barns/electron in either the Leduc or underlying Cooking Lake formation and were used to validate neutron-density lithology interpretations. Based on these well logs, it is evident there are vertical and lateral variations in the dolomitization trends across the complex.

Lithofacies were identified, interpreted, and delineated based on sedimentary structures and textures observed in core, and can be related to trends of porosity and permeability. Trends of porosity and permeability occur spatially and relate to depositional environments and diagenesis of the rock (e.g. McNamara and Wardlaw, 1991[lii]; Amthor et al. 1994[liii], McNamara and Wardlaw, 1991[liv], Mountjoy et al., 2001[lv]; Atchley et al., 2006[xxx]), and these trends formed the basis for stratigraphic definitions and facies coding used herein. The depositional model (Figure 17) showcases the three main facies identified and differentiated across the BD. Except for core 102/01-16-033-27W4, all cores examined by E3 were in the upper portion (1/3) of the Leduc reef. Therefore, these facies interpretations are representative of the upper Leduc.

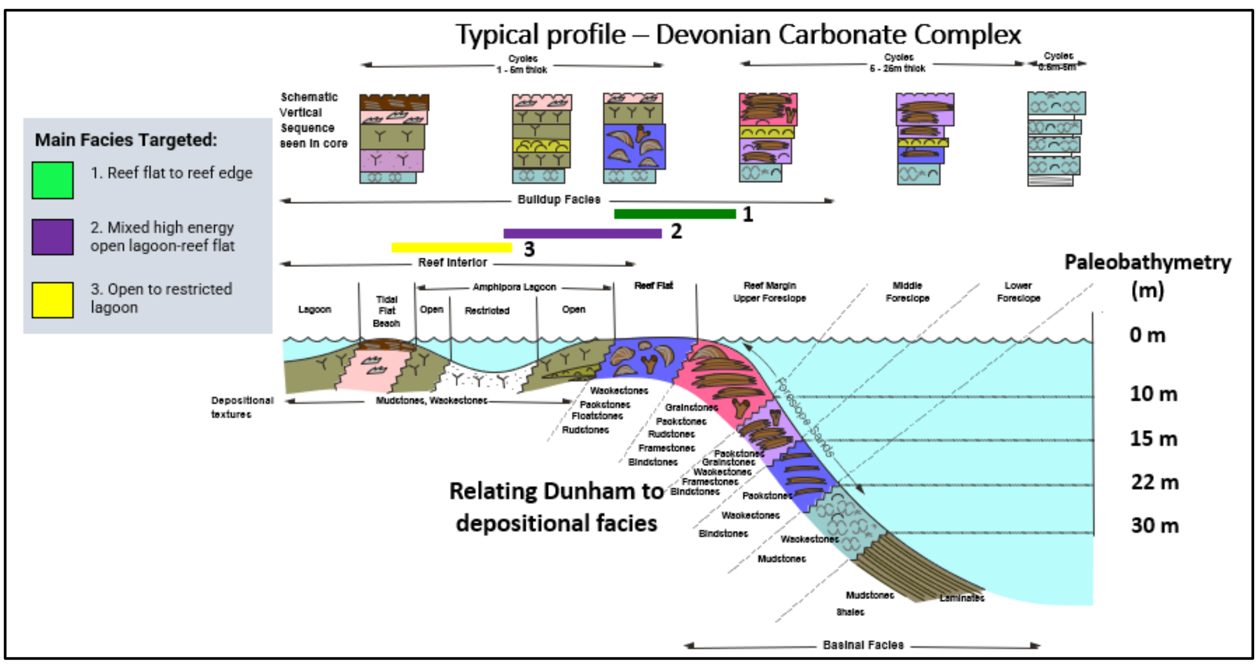

Figure 17: Depositional Model for typical Devonian carbonate complex, with the three facies interpreted in the upper Leduc Core in the Bashaw District

Credit: with permission to Drivet Geological Consulting, and modified from Nigel Watts 2008 (unpublished); Wendte and Stoakes 1982; Wendte 1992

These lithofacies were interpreted mainly by core descriptions across the BD (Figure 18). They are subdivided as follows:

1. Facies-1: Leduc Reef Flat to Reef Margin Facies
2. Facies-2: Leduc Mixed Reef Interior Open Lagoon to Reef Flat Facies
3. Facies-3: Leduc Reef Interior Restricted to Open Lagoon Facies

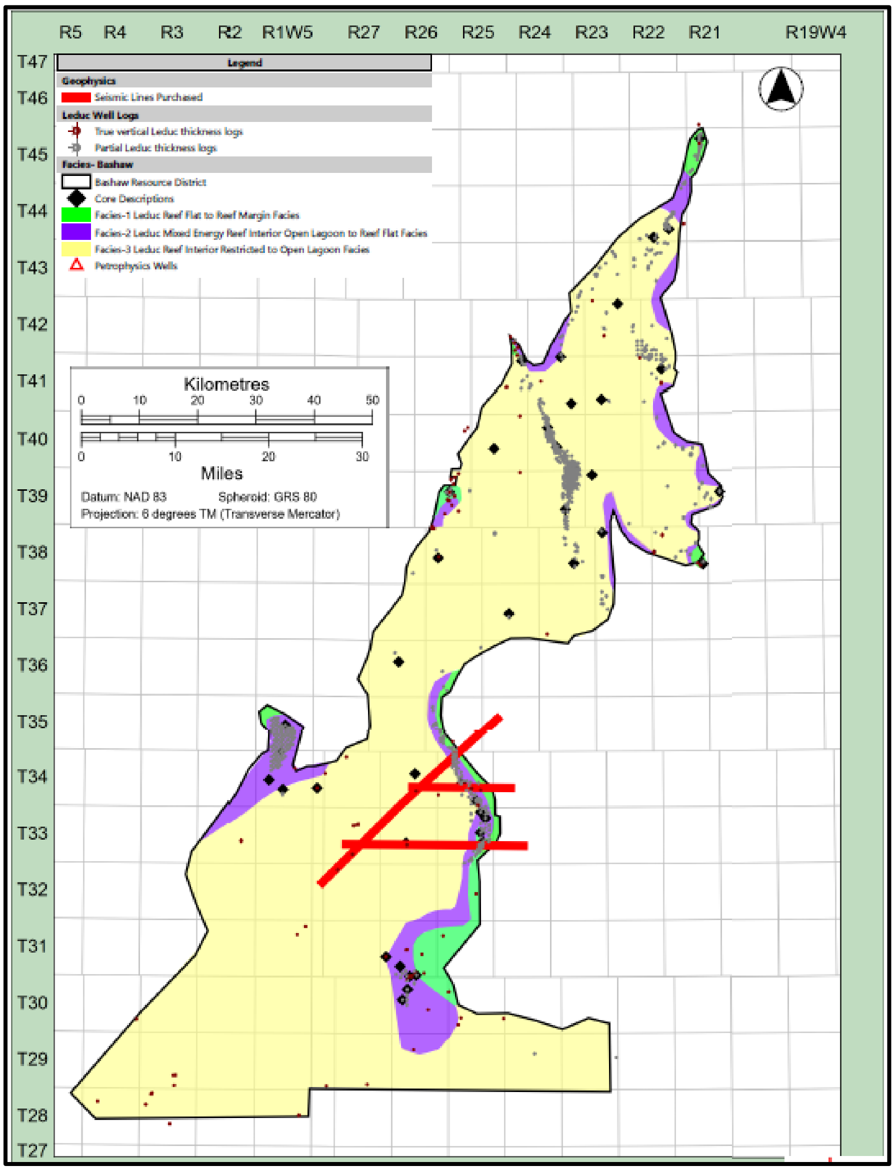

Figure 18: Upper Leduc Facies Distribution in the Bashaw District based on core descriptions (E3, 2022)

Facies-1, reef flat to reef margin and Facies-2, reef interior to open lagoon lithofacies indicate depositional environments closer to the zero edge of the reef complex. Textures in the core of the Facies-1 and -2 lithofacies suggest reworking of sediments (coated grains and reefal debris) along with in-situ reef growth with submarine cements (rudstone to framestone; after Embry and Klovan, 1971[lvi]), combined along with grain supported rock types- grainstones and packstones (Dunham, 1962[lvii]) (Figure 19). Facies-2 reef flat to reef interior open lagoon, is also characterized by grain supported rock types. By these criteria, it is interpreted both of these facies represent parts proximal to the reef margin where most of the aggradation and reef growth occurred (Figure 20). In addition, both Facies-1 and Facies-2 typically have highest porosity and permeabilities; this could be a result of proximity to the zero edge of the preserved reef, where higher degrees of filtering of finer grained material that would largely comprise the bulk of the matrix makeup of these facies, is occurring. Facies-3, reef interior lagoonal facies, is the dominant facies occurring in much of the interior of the Bashaw reef complex, on the back side of the reef flat. The reef interior is dominated by lagoons (Figure 21). These depositional environments are vertically more heterogeneous and consist of carbonate muds, storm washover debris, shoal reef material, and occasional patch reefs. Cores in the lagoon showed evidence for bioturbation, where a churned-reworked texture fabric was noted and was interpreted as being a primary depositional texture. Rock types representative of this facies in the core are dominantly matrix supported including floatstone with wackestone and mudstone matrix. Overall, the dominant skeletal reef builder in the Leduc complex across the BD and across each all three of the lithofacies are stromatoporoids.

Figure 19: Reef Flat to Reef Margin Facies

100/06-13-038-22W4 core photos; this core is primarily limestone (localized to this area) and intersects the Upper Leduc.

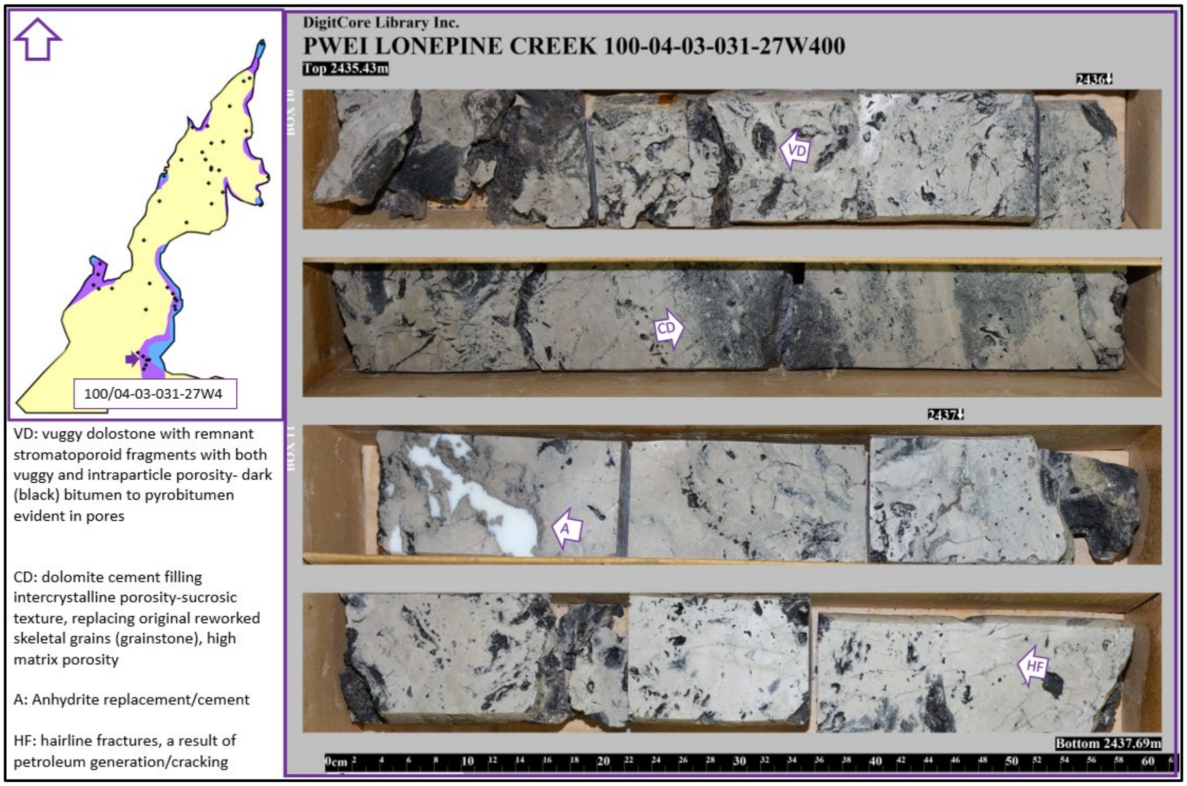

Figure 20: Open Lagoon to Reef Flat Facies

100/04-03-031-27W4 core photos; this core is proximal to the lone pine hydrocarbon pool and is a vuggy dolostone.

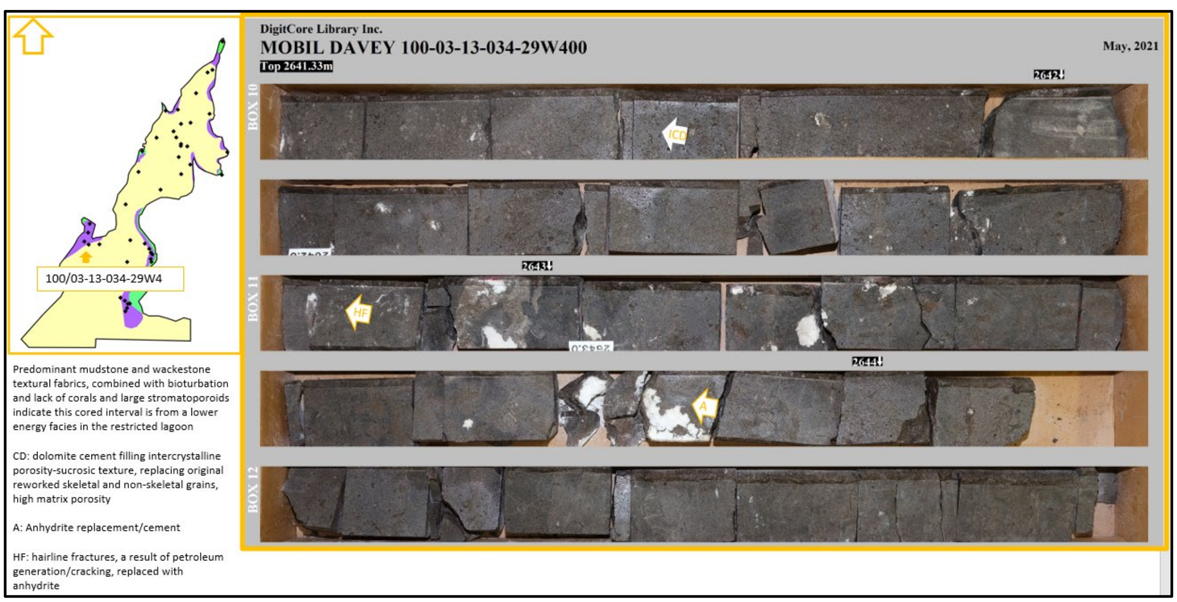

Figure 21: Restricted to Open Lagoon Facies

100/03-13-034-29W4 core photos; core is interpreted as restricted lagoon facies.

Characterizing cycle geometry for the Leduc in the study area is challenging because of the sparse well, core, and seismic data control in the Middle and Lower Leduc cycles. Based on the available data, the facies were assumed to be vertically continuous throughout the reef thickness. Drilling new wells through the full Leduc thickness away from existing Leduc data helped to interpret the geometry of the lagoon in the middle portion of the reef complex where there was previously sparse data, and clarified some of the previous assumptions about porosity, permeability, and cyclicity within the lagoon facies within the BD, which allowed for greater confidence when building the geologic model. Although three lithofacies were identified and have been mapped by E3, the resource volumes were determined using reservoir properties modelled for the combined Leduc reef complex volume within the BD. This is deemed to be a reasonable representation of the reservoir, as the important influence of facies distribution on the resource estimate is the facies controls on porosity and permeability. Because porosity data measured directly from the facies was used to populate the 3D porosity distribution, this is deemed to be an adequate representation of these large-scale facies trends for the purpose of the resource estimate. Further discussion is provided in Section 14 below.

The Cooking Lake Formation is a carbonate platform that sits beneath the Leduc. This formation encompasses the flow unit below the Leduc reservoir and above the Beaverhill Lake Group and is continuous beneath and beyond the BD.

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

7.8. Reservoir Dynamics

E3 conducted a flow test program on its 1-16-033-47W4 location to directly measure reservoir pressure and pressure response from production and injection into the reservoir. The flow test comprised: a production test flowed 400m3/d of brine to surface for 5 days; a pressure build-up for 7 days; an injection test of 1,200m3/d for 2 days; and a pressure fall-off for 2 days.

The pressure response was interpreted by and independent 3rd party subject matter expert from IHS Markit, a division of S&P Global. The interpretation relates the pressure response recorded to reservoir permeability of 20mD-100mD, and a minimum area of investigation of 3.1 sections (3.2km). Because the test was a single well test, total system compressibility could not be reliably estimated from the test and was assumed as a constant (for a single-phase system) for the purposes of the analysis.

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

Leveraging this publicly available pressure data, E3 graphed the data from the Bashaw Trend and the underlying Cooking Lake Platform. The pressure data was measured in wells distributed throughout the resource area. The data was graphed both as pressure vs. time and pressure vs. depth as both of these plots can be used to infer pressure continuity in the reservoir (Figure 22, Figure 23). The pressure vs. time is interpreted to show reservoir continuity if pressure decline in the reservoir during production follows a singular regional trend. The pressure vs. depth data can also be interpreted to support pressure continuity if the data follow a singular hydrostatic gradient (approximately 10 kPa/m), assuming static (i.e., non pumping) conditions. The pressure vs. time data shows that within the Bashaw trend, the Leduc is hydraulically connected across the reef to the lagoon portions of the reef complex (Figure 23). The underlying Cooking Lake Platform has lower permeability and porosity than much of the Leduc formation. Limited pressure data indicated that the pressure is different than the regional Leduc pressure (Figure 22), but it may be in communication with the Leduc due to the fact that there is limited data showing porosity and permeability (Table 4); if the Cooking Lake has some areas or facies with higher porosity and permeability this could allow some pressure and fluid communication through the Cooking Lake over time.

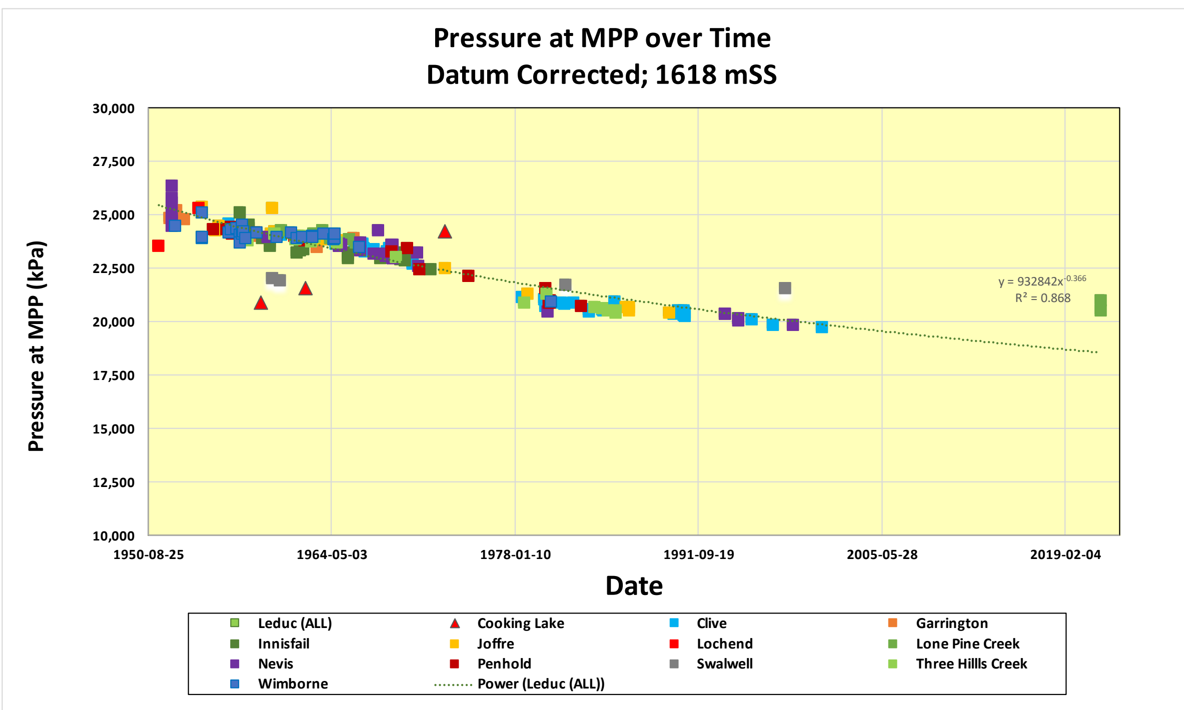

Figure 22: Leduc Regional Pressure vs. Time Data

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

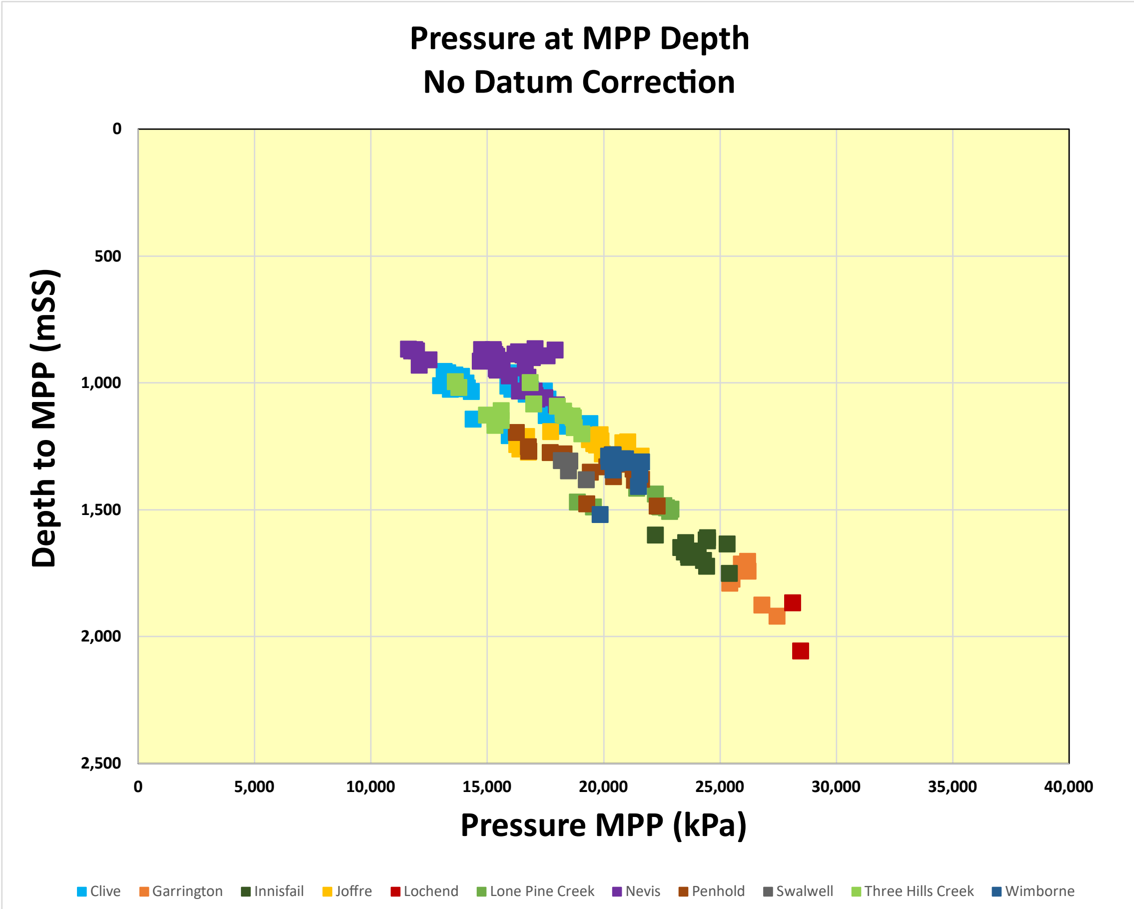

Figure 23: Leduc Regional Pressure vs. Depth Data

Based on the production and injection volumes, E3 calculated the overall void replacement ratio (VRR) for the BD (Figure 24). VRR is an oil and gas term describing the ratio of volumes of injected fluid to produced fluid at reservoir conditions, and a VRR of 1 is required to maintain reservoir pressure. The BD VRR is 0.39, which correlates with the decrease in reservoir pressure since the 1960's. Tabulated VRR for each pool can be found in Appendix C.

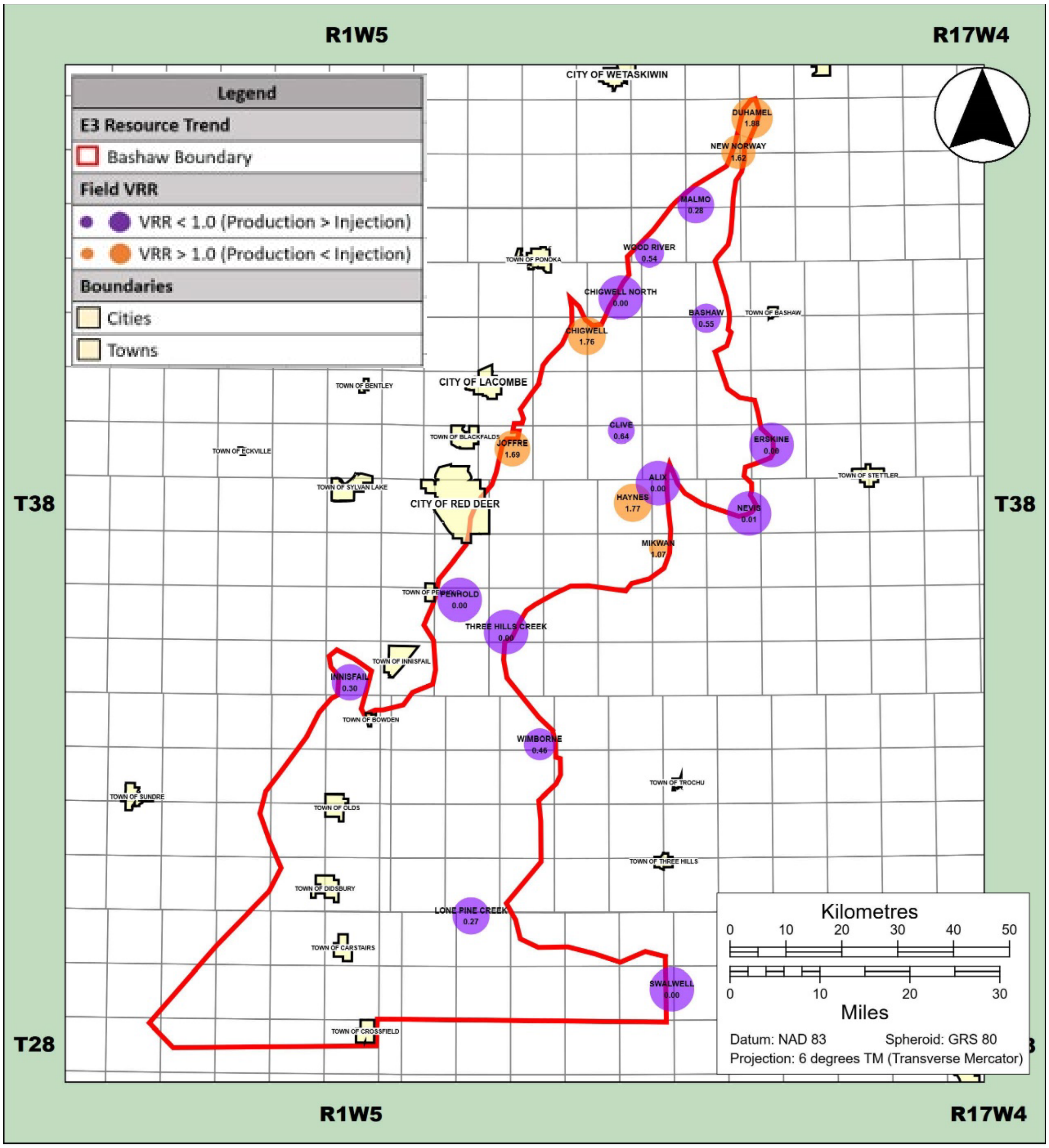

Figure 24: Voidage Replacement Ratio from Hydrocarbon Pools Across the Bashaw District

While the overall BD voidage replacement ratio is significantly under 1 at 0.40, injection of both water and gas does occur in some pools. The orange circles in the above map, found in the northern portion of the BD, show areas where the VRR > 1, meaning that cumulative injection volumes are greater than cumulative produced volumes. While injection does also occur in the southern portion of the BD, the VRR is < 1, meaning that cumulative injection volumes are less than the cumulative produced volumes. These conditions will influence the modern-day pressure distribution in the reservoir relative to its original static conditions.

7.9. Mineralization

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

The main lithium accumulations in E3’s properties occur within brines contained within dolomitized reefs complexes of Devonian Leduc age, with a secondary accumulation occurring at a higher elevation in the biostromal development in the Nisku Formation of the Devonian Winterburn Group. Consequently, Li-brine mineralization in the project area consists of Li-enriched brines that are hosted in porous and permeable reservoirs associated with the Devonian carbonate reef complexes. As discussed in Section 7.2, the specific emplacement method for the Lithium in these reservoirs is currently unknown and is an active area of research. For the Leduc and Nisku system in southern Alberta, Huff (2016)[xi] proposed a source involving lithium concentrated Devonian evaporates to the west and upward movement of Li-enriched brine into the Leduc and Nisku carbonates during later mountain building. E3’s current conceptualization of the resource is that the lithium grade is relatively homogeneously distributed within the connected reservoir of the BD due to the relatively high permeability and connected nature of the reservoir.

Data collected during E3’s 2022 evaluation well program supports this theory, as all samples collected have a very narrow range of P10-P90 concentrations (Section 11.4). The lithium data has been collected across the 65+ townships of the BD, and E3’s evaluation well program acquired lithium concentrations across the vertical extent of the Leduc Formation. Additionally, major cation and anion geochemistry concentrations do not vary significantly across the BD which further supports the interpretation that the brine is continuous. A summary of this information is presented in Table 5.

Table 5: Major Ion Distribution Across the Bashaw District

	Bicarbonate (HCO_3) [mg/L]	Dissolved Chloride (Cl) [mg/L]	Dissolved Sulphate (SO_4) [mg/L]	Dissolved Calcium (Ca) [mg/L]	Dissolved Magnesium (Mg) [mg/L]	Dissolved Sodium (Na) [mg/L]	Dissolved Potassium (K) [mg/L]
P90	310	127,280	186.7	19,120	2,562	44,060	5,782
P50	506	134,000	392.6	21,500	2,920	49,000	6,185
P10	772	162,000	515.8	24,900	3,434	53,440	6,669

8. Deposit Types

Lithium deposits worldwide were ~80 million tonnes in 2020[lx], and fall into two broad categories: hard rock deposits (spodumene, hectorite, and pegmatites); and lithium-rich brines. Lithium clay or sedimentary deposits are an emerging resource, where lithium is found in clays adjacent to salt lakes, in lacustrine evaporites, or from the weathering of volcanic rocks and their associated by-products. Hard rock deposits are commercially mined in Australia and China, with developments at various stages elsewhere across the globe. Brine-hosted lithium deposits are accumulations of saline groundwater that are enriched in dissolved lithium and other elements that can occur at almost any depth between surface and the basement, and are commercially produced in Argentina, Chile, China, and the USA. Salars host lithium-rich brines that occur at or near surface and concentrate lithium (and other minerals) through solar evaporation.

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

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

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

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

9. Exploration

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

In addition to E3's 2022 evaluation well program (described in Section 10), exploration activities to date have included brine sampling from existing hydrocarbon wells. Samples were collected from existing Leduc Formation producing oil and gas wells by field technicians contracted by E3 from Bureau Veritas Labs (BV) in Red Deer, Alberta. All wells producing solely from the Leduc Formation, without any additional concurrent zone production (commingling from other formations), were earmarked for sampling, and were accessed based on availability. Oil and gas operators generally cycle wells, so several field programs were completed to collect samples. Samples were either collected directly at the wellhead, or at test separators, by BV employees wearing self-breathing apparatuses due to the presence of H_2S (hydrogen sulfide) gas. The following sampling procedure was followed such that samples were collected, sealed, and labeled to avoid contamination and tampering, and ensured proper chain of custody measures were in place.

9.1. Field Sampling – Existing Oil and Gas Infrastructure

Samples were either collected directly at the wellhead, or at test separators. Where sampling was conducted at the wellhead, a 4L jug was used to collect the production fluid at the pump jack. This fluid typically formed an emulsion of oil, water and gas, which readily separated out into phases in the bottle within seconds to minutes. Once the separation was complete, a small hole was created in the bottom of the bottle to allow only water to flow out of the 4L bottle and into a 1L opaque amber glass bottle (Figure 25).

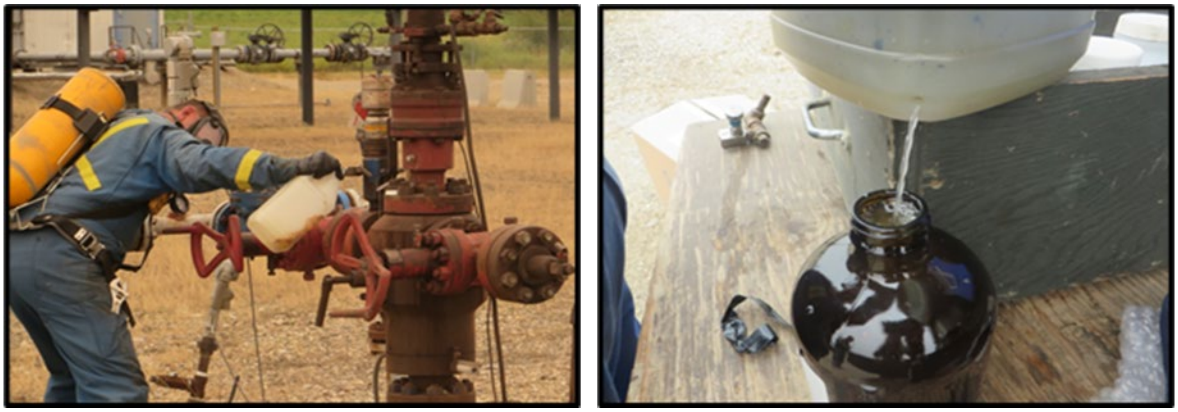

Figure 25: Sample Collection at Wellhead

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

Samples were also collected at test separators. Test separators are used in the oil and gas industry to measure the flow rates of various wells and collect water and hydrocarbon samples from one or more wells at a satellite location (Figure 26). Test separators for this resource sampling program were either 2-phase or 3-phase. 2-phase means that oil and water are separated from gas, whereas 3-phase means that oil, water and gas are each separated. For both 3-phase and 2-phase, there is a valve on the tank that can be opened to produce a fluid sample. In all cases, the company ensured that the wells used went "into test" at least 24 hours prior to sample collection to flush the lines and minimize the risk of contamination from other wells.

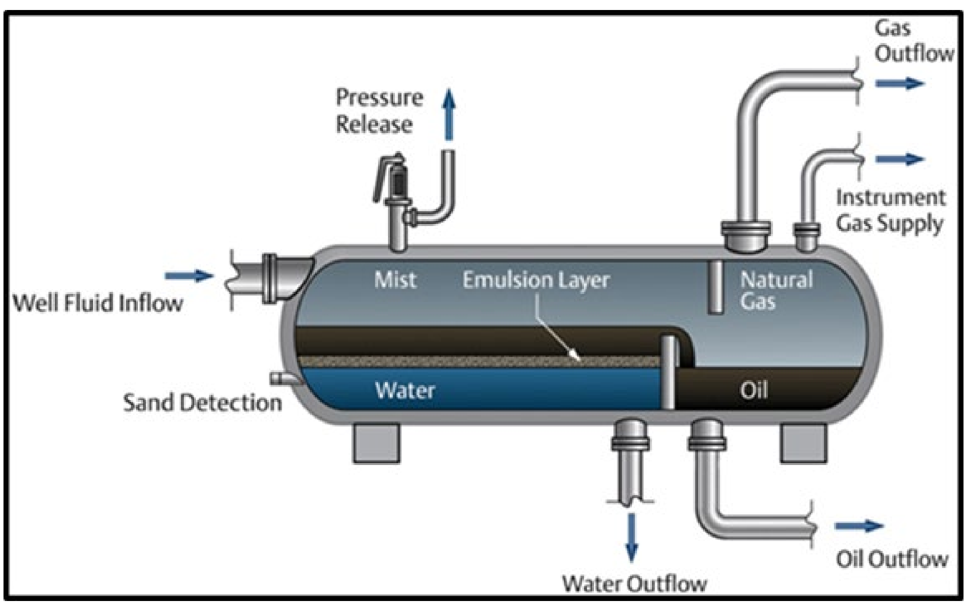

Figure 26: Schematic of Test Separator (Emerson[lxv], 2020)

On 2-phase separators, the valve was opened, and water was discharged into a test bottle to assess how much oil was in the separator before collecting directly into the opaque amber bottles. If there was a high volume of oil, sometimes the operator of the well was able to adjust on site to improve the amount of water flow. After adjustments were made, a mixture of oil and water was discharged into the 1L opaque amber bottles (Figure 27).

Figure 27: Sample Collection at Test Separator

Left: Bureau Veritas employee collecting sample from test separator access port.
Right: Sealed well samples.

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

In all cases, two 1L opaque amber bottles of sample were collected on each well. The bottles were filled up to the very top with reservoir water to ensure no air could get trapped in the top. A cap was then screwed on, and the cap was sealed with electrical tape. An E3 custody seal was affixed to the bottle and cap to ensure no sample tampering (Figure 27). These bottles were kept in a cooler with their chain of custody documents and delivered to the laboratory for testing once the sampling program was complete.

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

A list of well additives, such as demulsifier, corrosion inhibitor and paraffin inhibitor, was obtained for each wellsite to rule out potential lithium contamination. No sources of lithium contamination were identified after a review of the Safety Data Sheets (SDS's).

A total of 44 samples from different Unique Well Identifier's (UWI's) were collected for analysis in the BD, collected from 2017 to 2022.

In addition, large volume samples (3 to 20 m^3) have also been collected using the same methods outlined above from 3-phase separators in 2018 and 2019. With large volume collections, Leduc brine was treated directly to remove H_2S using AMGAS proprietary CLEAR[lxvi] technology and stored in 1 m^3 totes.

10. Drilling

The first E3 wells, targeting the Leduc for the purposes of evaluating brine for lithium concentrations, were drilled in the summer of 2022. E3 drilled two wells and a third well was acquired through another operator in the fall of 2022, with the intention to test the Leduc brine for lithium. All three wells are located in the southern portion of the Bashaw reef complex (Figure 28). A brief overview of the operations of both these wells and sampling procedures is detailed below.

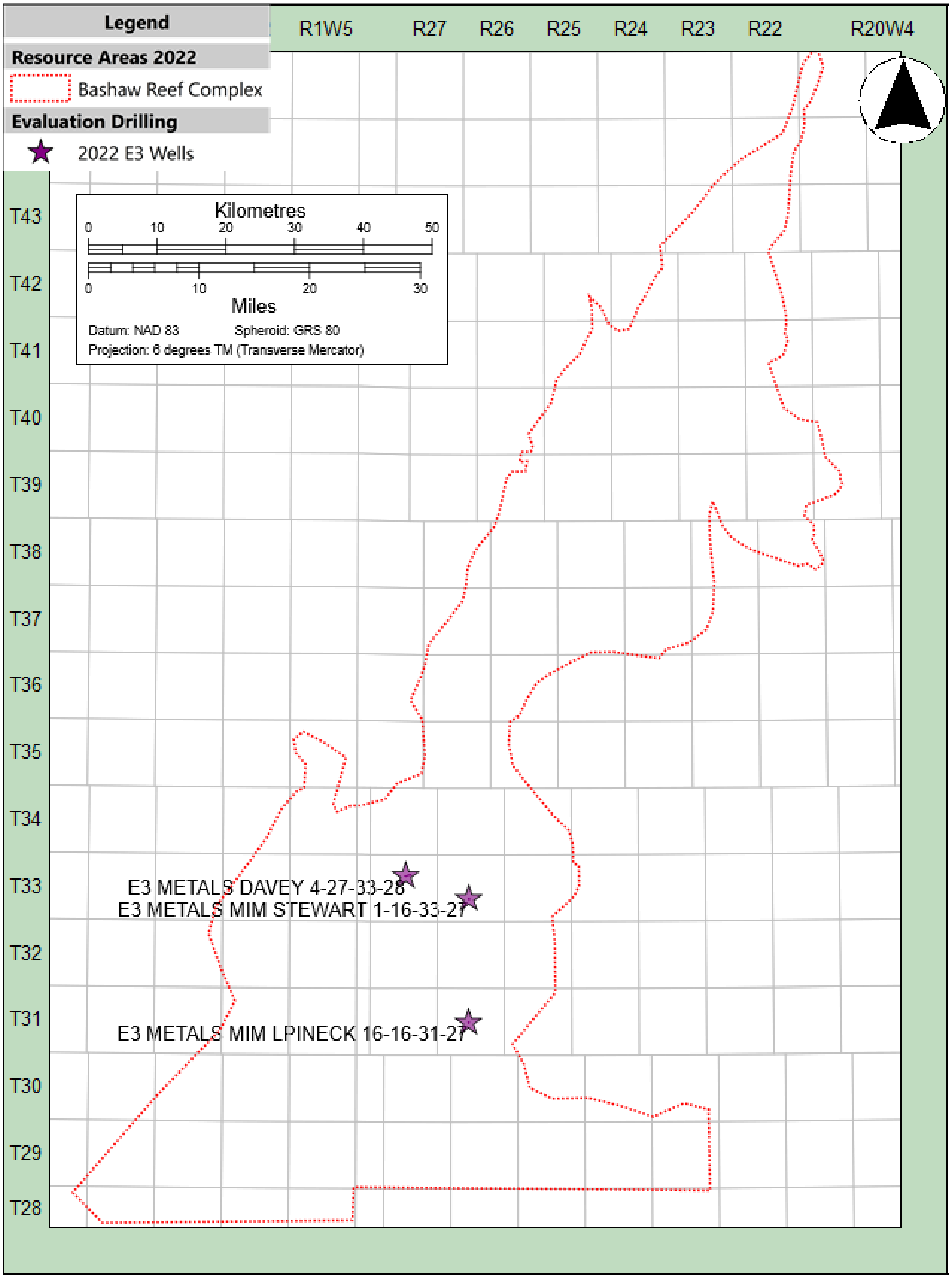

Figure 28: 2022 E3 operated wells, drilling and completions.

10.1. 102/01-16-033-27W4 (E3 Drilled and Completed)

A vertical well, E3 Metals MIM Stewart 1-16-33-27W4 spudded on June 23, 2022 and reached a total depth of 2670.00m on July 07, 2022. The top of the Leduc reservoir was intersected at a measured depth of 2415.36 m. Three cores were cut at this well, a total of 36.9m in core between a measured depth of 2490-2589 along the wellbore. The total thickness of the Leduc reservoir in this well was 210.6 m.

The well set intermediate casing point (ICP) at 2437.8m measured depth, the top of the Leduc. Below ICP, a system of tubing strings with six shiftable sleeves placed between packers and joints manufactured by NCS Multistage was installed in the hole (Figure 29). One sleeve was placed in the Cooking Lake formation, and the other five sleeves were in the Leduc.

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

Samples were collected from a testing vessel at surface, where the downhole fluids were produced to, prior to following the Standard Operating Procedures described in section 9.1 Field Sampling.

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

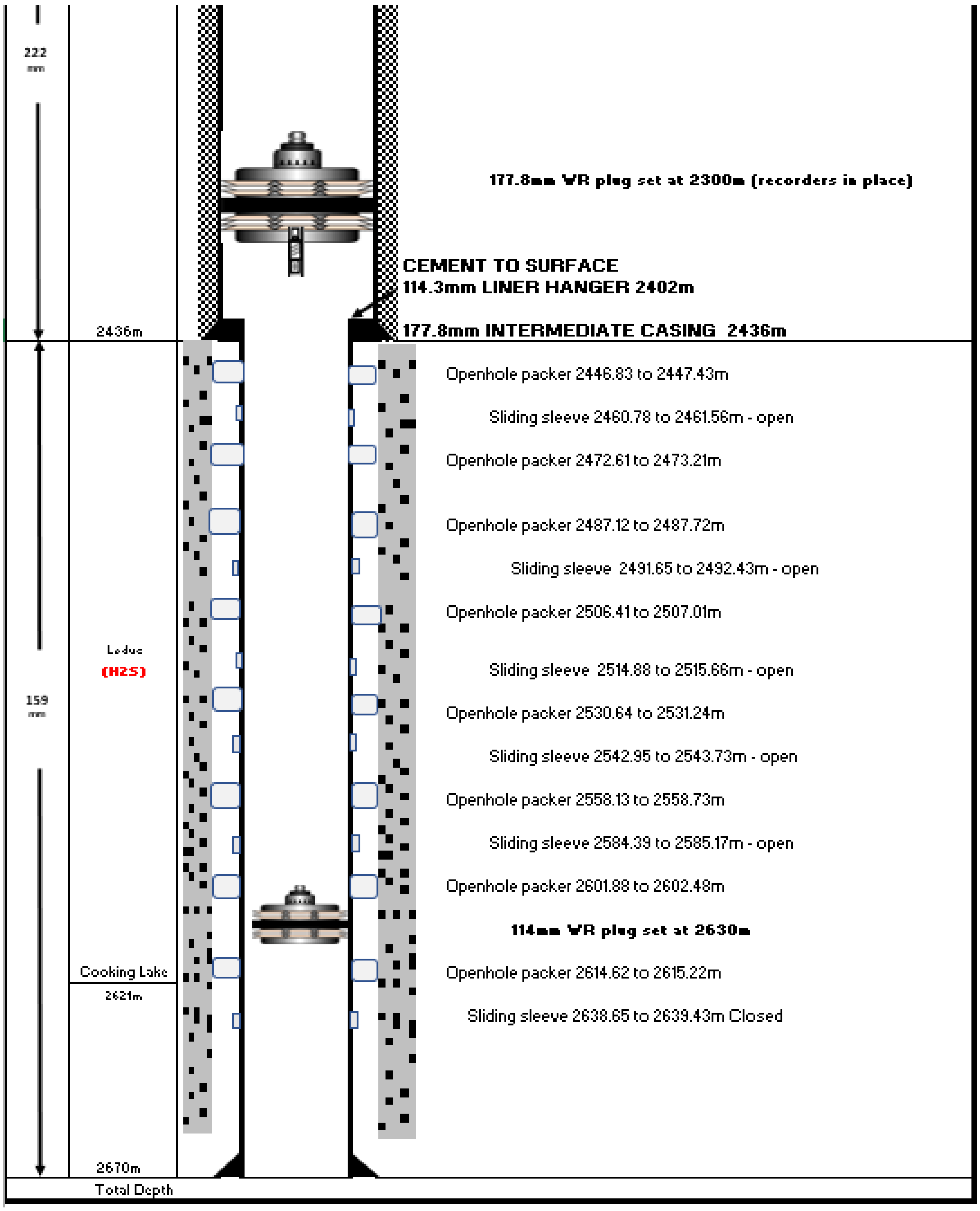

Figure 29: Completion diagram/schematic for E3's 102/01-16-033-27W4 well

10.2. 102/16-16-031-27W4 (E3 Drilled and Completed)

A vertical well, 102/16-16-031-27W4, spudded on July 23rd, 2022 and was rig released on August 6th. The top of the Leduc reservoir was intersected at a measured depth of 2450.5 m and the total depth of the well was reached at 2722.3 m.

ICP was set at a measured depth of 2469m (Figure 30). Six sleeves were placed along the liner, with packer and joint separation; five sleeves were placed in the Leduc and the sixth sleeve in the underlying Cooking Lake and Beaverhill Lake formations.

Sampling operations commenced September 6th, following the same procedure described above for 01-16-33-27W4, but not all intervals were sampled as confidence in the vertical grade distribution was increased following the results from the first well. Three sleeves in the Leduc were sampled, at depths to represent the base, middle and top of the Leduc reservoir (Figure 30).

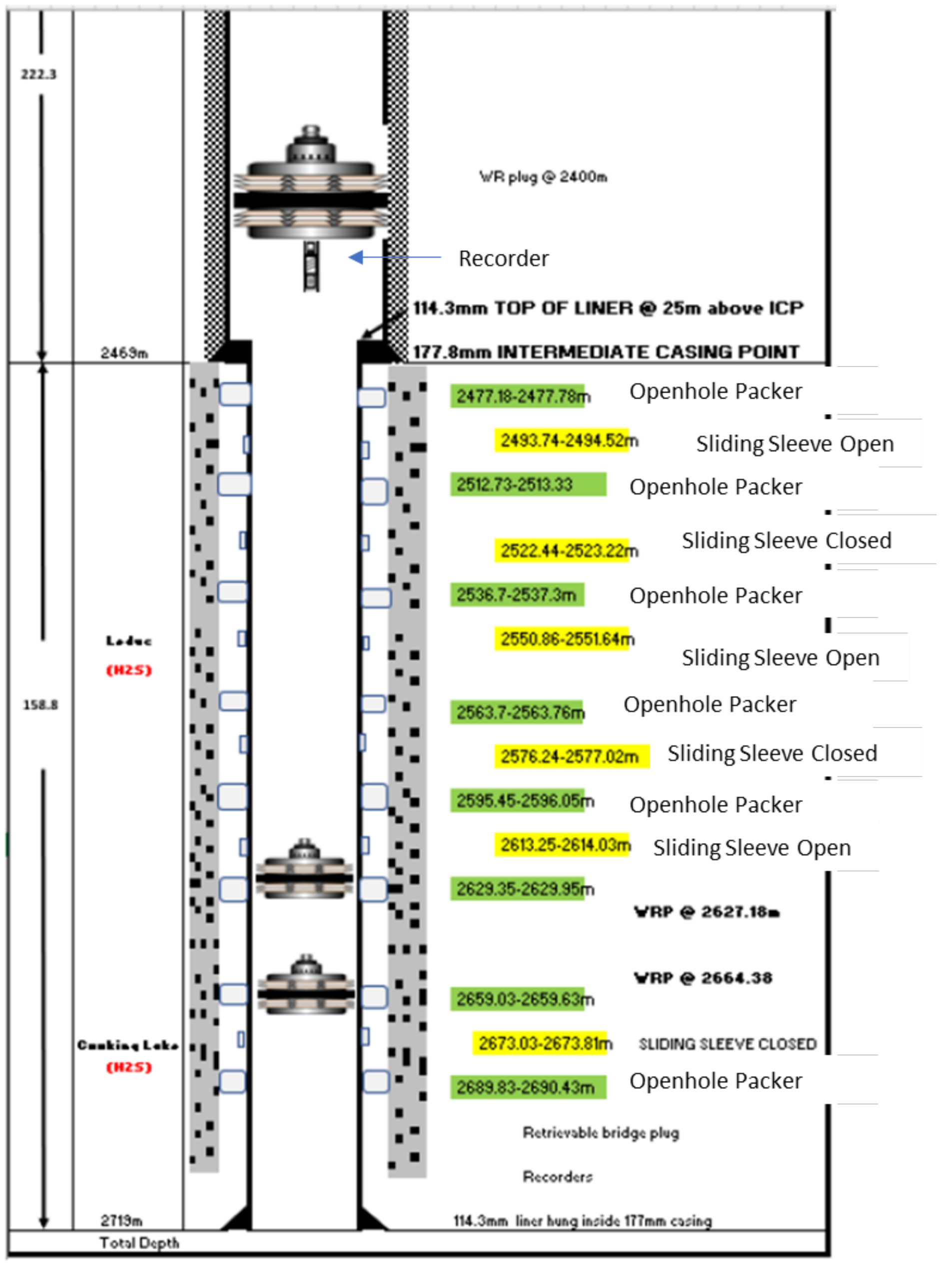

Figure 30: Completion diagram/schematic for E3's 102/16-16-031-27W4 well

Respective 'open' sleeves, designate which intervals samples were retrieved from.

10.3. 100/04-27-033-28W4 (Third Party Drill; E3 Completed)

The 100/04-27-033-28W4 was a wildcat exploratory well drilled and completed in October 2021 by Aspenleaf Energy. The wells target objective was the Beaverhill Lake Group, a zone below the Leduc formation. This well is deviated; the top of the Leduc intersected a true vertical depth (TVD) at 2546.7m and the base of the Leduc, the Cooking Lake formation is 2749.1m, therefore the true vertical thickness of the Leduc reservoir is calculated to be 202.4m at this wellbore.

Since this well was targeting a deeper objective, the ICP was set deeper than the Leduc (Figure 31). E3 perforated the casing to obtain samples in the Leduc. The well exhibited scaling and corrosion in the casing, as well as significant skin damage that occurred during drilling. Therefore, only one of the perforation intervals was sampled, at a depth from 2646.04-2647.44m TVD. E3 is evaluating options for future re-entry and clean-up of this wellbore for additional sampling.

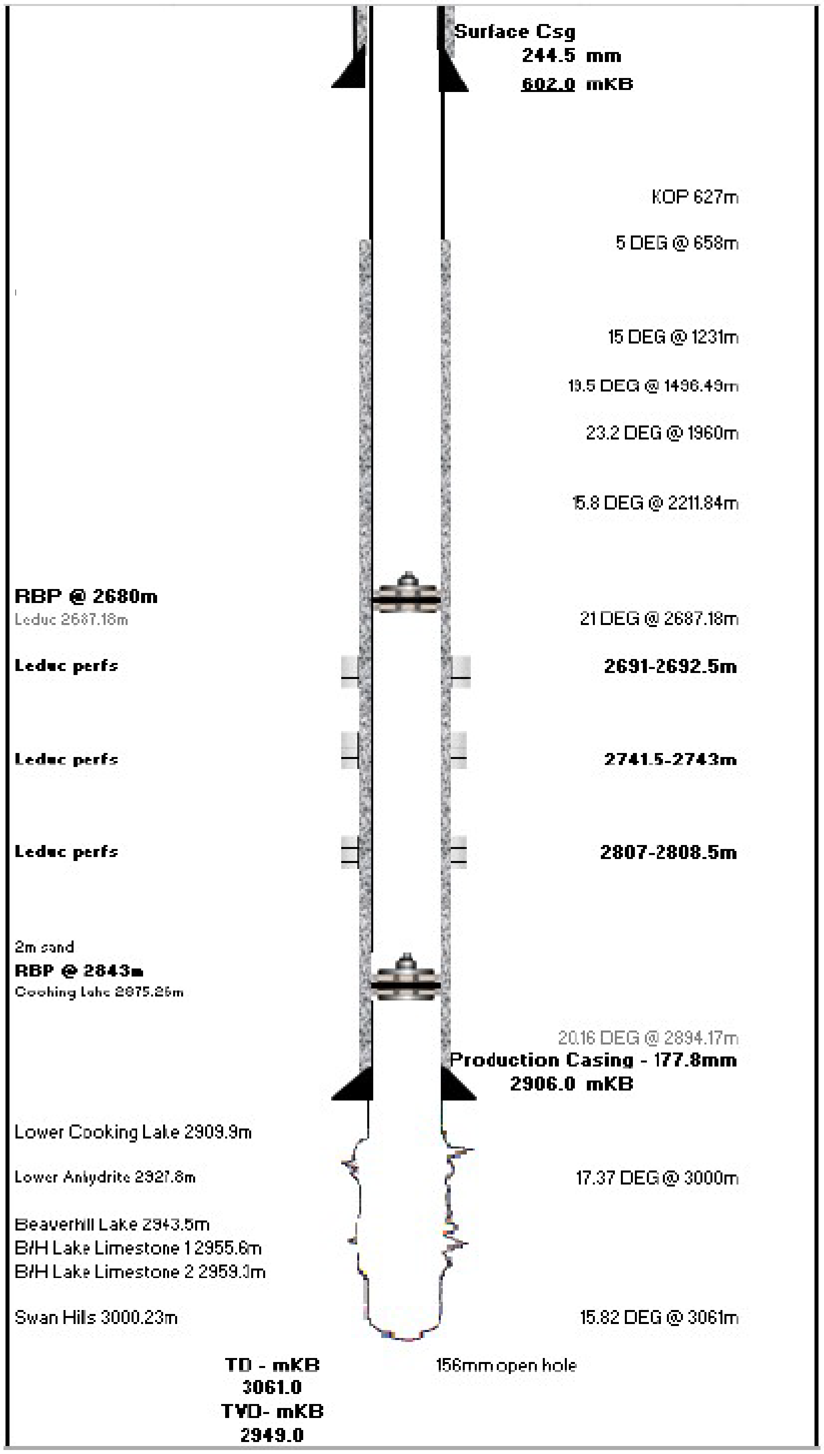

Figure 31: Completion diagram/schematic for acquired 100/04-27-033-28W4/00 well

The well was perforated in three zones, and one sample was collected from the middle zone (2741.5-2743m).

11. Sample Preparation, Analyses, and Security

11.1. Sample Preparation and Security

The general sampling procedure was consistent for samples collected either from existing oil and gas infrastructure (Section 9) or dedicated exploration wells installed and sampled by E3 (Section 10). All samples were collected into 1L opaque amber bottles. The bottles were filled to the top to ensure no air was trapped at the top. The cap was screwed on and then sealed with electrical tape. Each bottle was labeled with the Unique Well Identifier (UWI), sample interval depth, date, and an E3 custody seal was applied for security. These samples were kept secure in a cooler with their chain of custody information and delivered either to Bureau Veritas Laboratories (BV) Edmonton or AGAT Laboratories Calgary and SGS Geochemistry Division, Lakefield, ON for processing. BV, SGS and AGAT labs are accredited by the Canadian Association of Laboratory Accreditation Inc.

11.2. Analyses

In the laboratory, samples were first degassed to primarily get rid of H_2S. Samples from the same UWI were combined into a large beaker in a fume hood for H_2S degassing. A reference beaker of water was placed beside each sample to measure the degree of evaporation over the degassing period. This evaporation was found to be <1% for all samples and is reported along with the lithium result. After H_2S removal, the larger sample was stirred using a stir-bar for at least 1 minute prior to subsampling to ensure sample homogeneity. Then 100 ml or 125 ml of sample was discharged into two opaque amber glass or high-density polyethylene bottles for trace metals testing at SGS Lakefield (assay lab) and BV Calgary where routine water analyses were run, providing duplicate testing to verify trace metal results. The degassing lab (BV or AGAT) packed and shipped samples to their respective destinations with chain of custody documents, as the trace metal lab testing facilities are not equipped to handle sour samples

Samples received at the individual labs were mixed vigorously and a subset of sample was placed in a digestion tube. All samples taken prior to 2022 (present year) were first digested with hydrogen peroxide, and then digested again with a mixture of nitric acid and hydrochloric acid. The purpose of the hydrogen peroxide digestion is to break down humic acid and various organics in the sample that are believed to interfere with the lithium measurement. Third party operator samples collected in 2022, did not go under a double digestion and were only digested once with the nitric acid and hydrochloric acid step. Post digestion, samples were then diluted and run through an Inductively Coupled Plasma - Optical Emission Spectrometry (ICP-OES) machine for trace metals analysis. Samples collected from the three E3 wells had trace metals measured with SGS geochemical division (laboratories) in Lakefield, Ontario. The samples were diluted with 20% HCl for the ICP-OES and 2% HCl for the Inductively Coupled Plasma-Mass Spectrometry (ICP-MS); a combination of both practices is used for the 30 trace metal analyses. Further breakdown of how these analyses were run is included in the appendices (Appendix D).

11.3. Certified Reference Material Verification

A round robin was completed in Q4 2021, as a process to get a certified reference material lithium concentration for resource brine from the 100/10-29-030-27W4/00 well. A total of 70 samples of produced Leduc brine were sent to a total of seven labs. Laboratories in this round robin included, BV

Environmental Lab (Calgary); BV Mineral Lab (Vancouver); ALS Environmental (Vancouver); CARO Analytical Services (Vancouver); SGS Minerals (Lakefield); SGS Environmental (Lakefield); and AGAT Labs (Calgary). Ten samples were sent to each of these labs, and samples were processed using a double digestion- first digested with hydrogen peroxide, and then digested again with a mixture of nitric acid and hydrochloric acid; and standard single digestion for ICP with nitric acid and hydrochloric acid mixture (Figure 32).

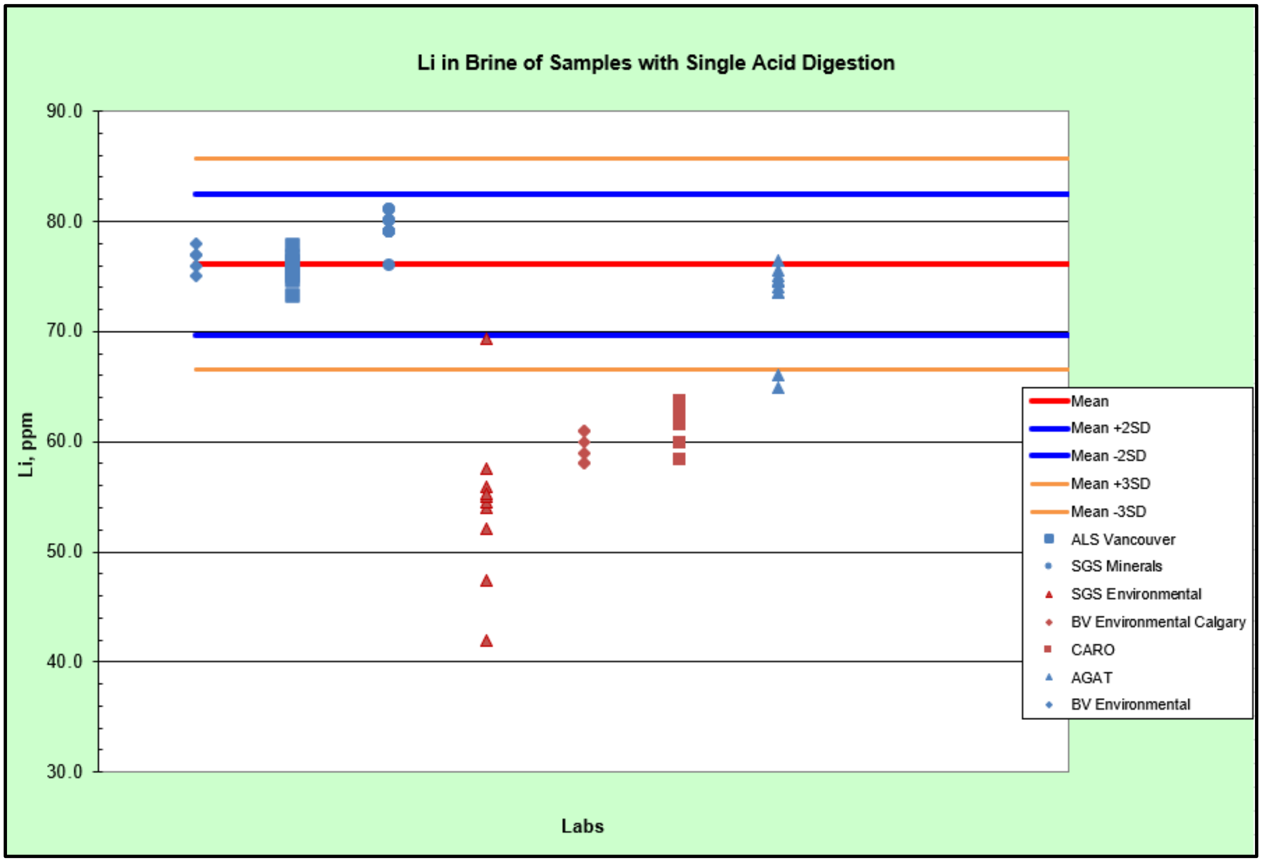

Figure 32: Lithium Concentrations from Lab Results Ran with a Single-standard Digestion

Of the seven labs used, three of these labs (SGS Environmental, BV Environmental and CARO) did not use ICP-OES, instead they used ICP-MS which does not accurately measure Lithium concentration. Due to this inconsistency, these labs lithium concentration results were not used to determine the certified reference material.

Out of the seven labs, only three were able to run samples with the double digestion (Figure 33). Of the three labs, only AGAT used the preferred method of analysis-direct aspiration of the brine into an ICP-OES. The little variation in lithium concentrations between the AGAT samples ran with a single standard digestion and those run with a double digestion showed this extra digestion step is unnecessary for the Leduc brine resource (sourced from well 100/10-29-030-27W4/00).

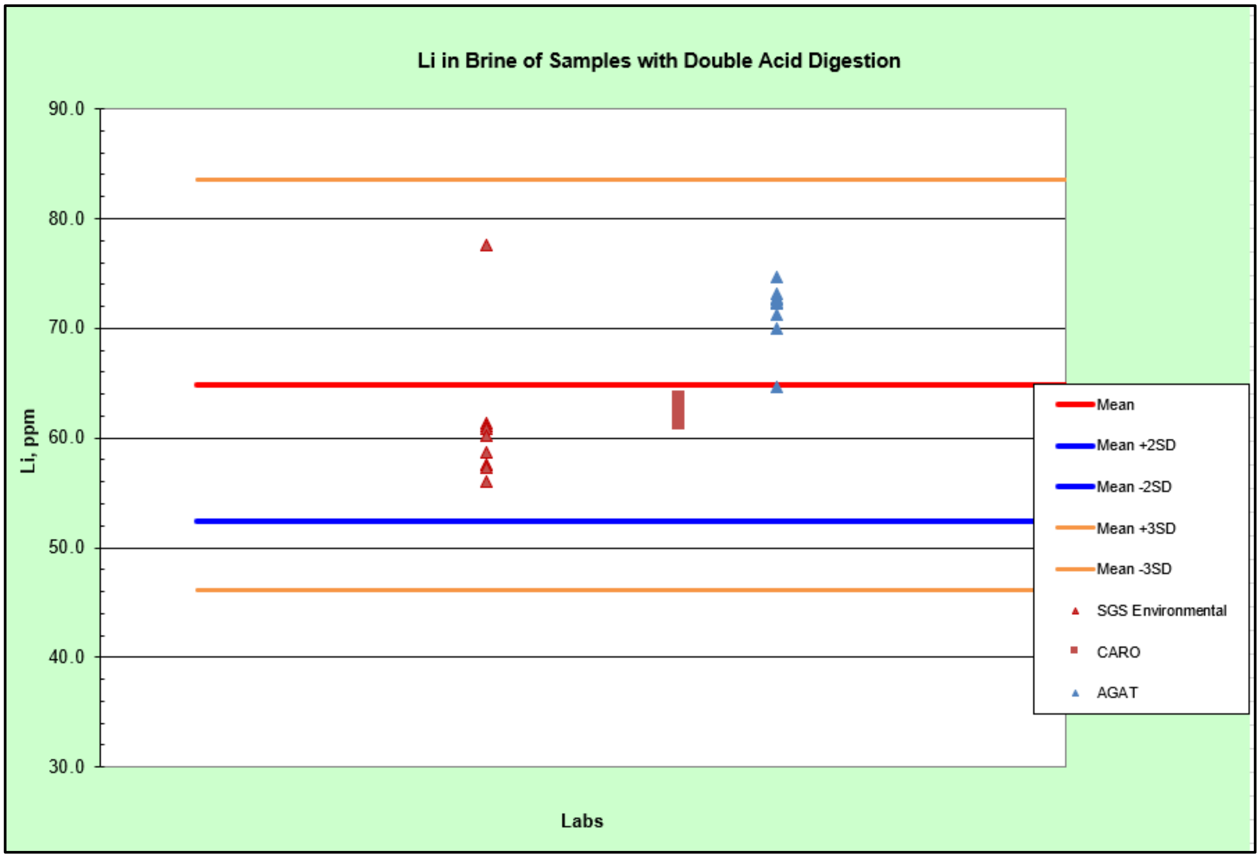

Figure 33: Lithium Concentrations from Lab Results Ran with a Double Acid Digestion

In summary, the certified mean of 76.1 mg/L was signed off and assigned, largely based on the single digestion sample subset, of the four labs that used the appropriate methods for analyses. This certificate was signed off by Barry W. Smee, P.Geo, PhD, FGC on March 2022 (Appendix E).

11.4. Sampling Program Results

To date 86 Leduc brine samples have been collected by E3 across the BD (Figure 34, Table 6). E3 has excluded the publicly available data (Section 6.5) as it cannot be confirmed that the samples followed an equivalent to E3's Standard Operating Procedure with Chain of Custody (Section 11.1) and they were not witnessed by the QP, which is required for CIM 43-101 disclosure. Of the sample data contained herein, a subset of these samples come from the same well (44 unique UWI's sampled). At each well location, there may be different vertical intervals of the Leduc Aquifer that were sampled (6 intervals at 01-16-033-27W4 and 3 intervals at 16-16-031-27W4) and there are also samples that were collected from the same well and interval over time (34 repeat samples). The methodology for evaluating the lithium concentration at each location has changed in this technical report as compared to historical technical reports. In past analysis, samples were aggregated at each location including temporally different samples and those collected at different depths vertically in the reservoir. In this updated analysis, vertically different samples were treated as unique samples so that vertical heterogeneity within the reservoir could be evaluated. For intervals with multiple samples over time, a mean value was calculated after a qualitative review that the samples had low variance in the temporal scale. This revised approach, in addition to the fact that more samples have been included in this report, has resulted in some differences in the minimum, maximum and mean lithium concentrations reported in this technical report versus previous technical reports.

Based on the sampling results, the Leduc is enriched in lithium in sampled wells across the BD, and the data demonstrates consistency throughout both horizontally and vertically (see Ch. 14 for further detail). The QP validated that the data presented in this section has resulted from adequate sample preparation, security and analytical procedures. Figure 35 shows the histogram of the sampling data.

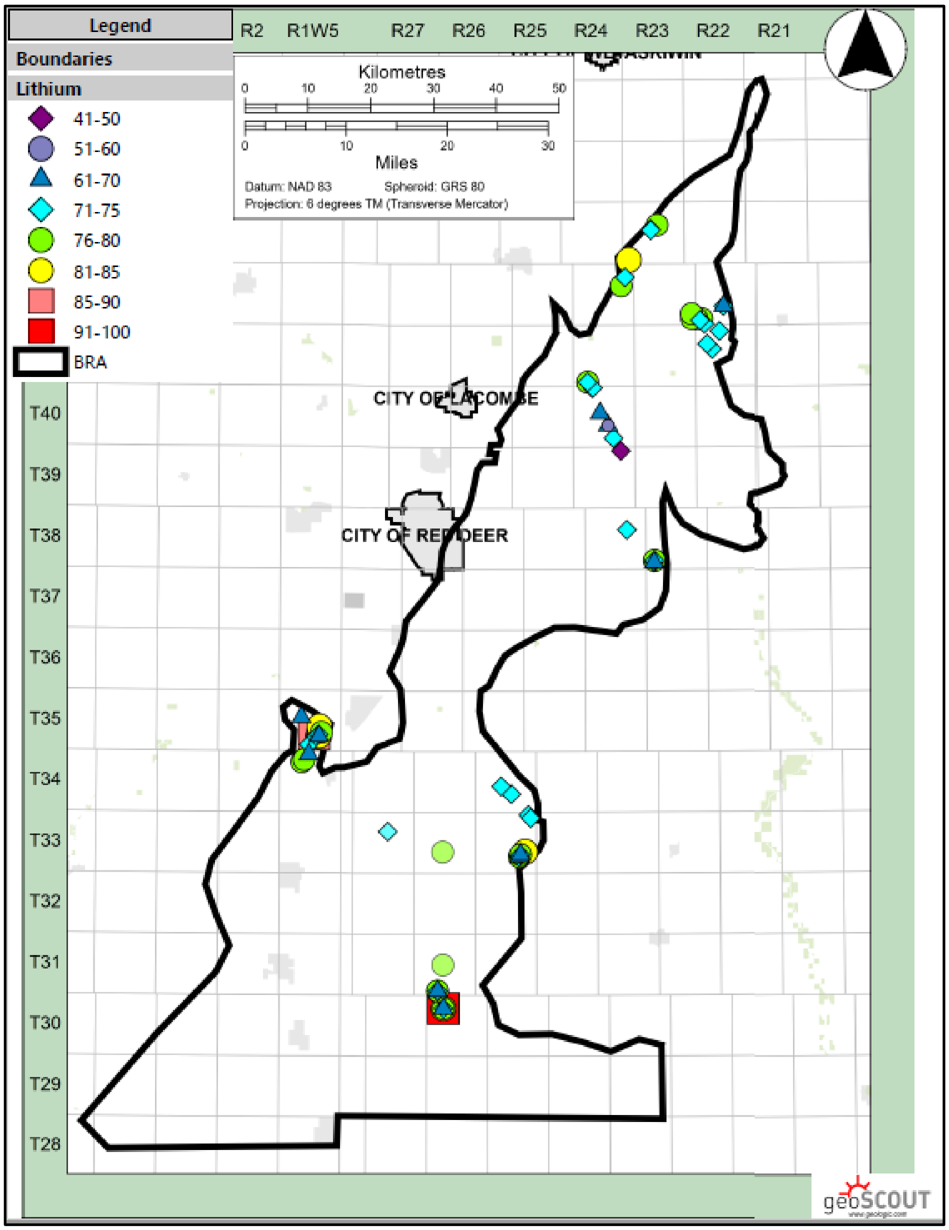

Figure 34: Lithium results across Bashaw District

Table 6: Sampling Results averaged per well's sampled from E3's Programs (2017-2022)

Resource Area	Min Li [mg/L]	P50 Li [mg/L]	Max Li [mg/L]
Bashaw	58	74.5	86.4

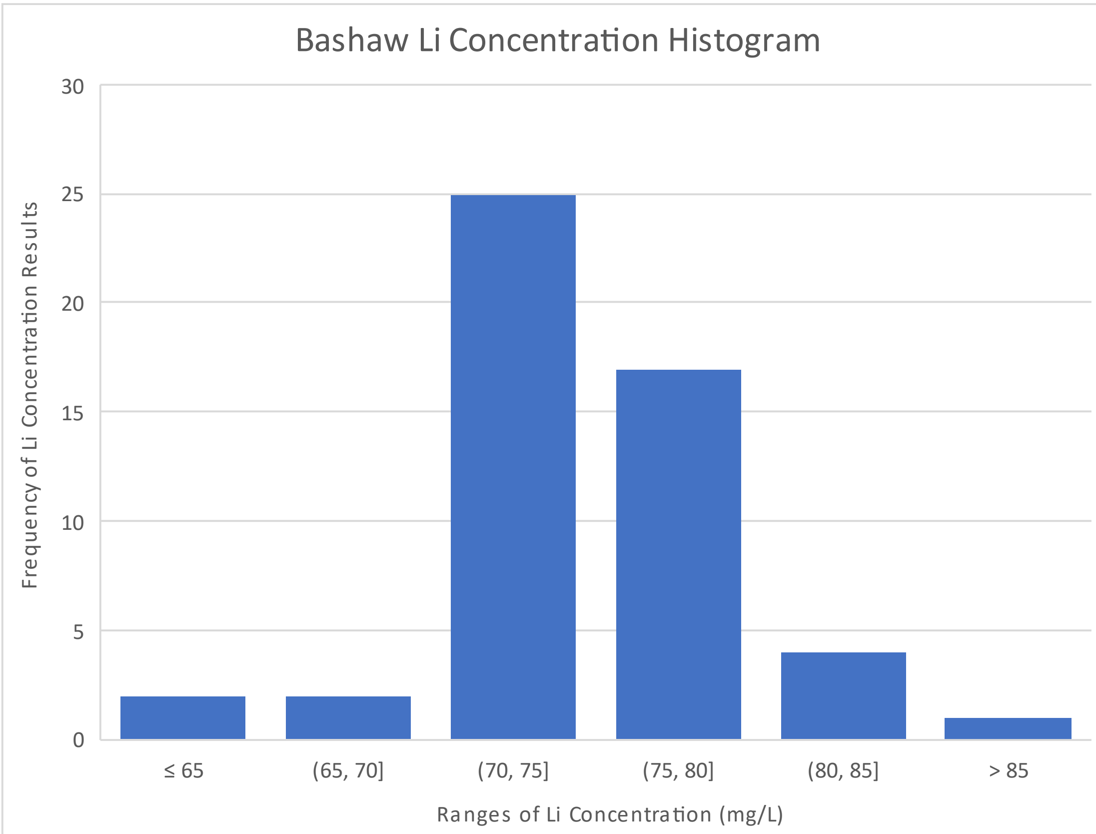

Figure 35: Bashaw District Lithium Concentration Histogram

Averaged value for sampled interval per wells with repeat samples

Of the 86 samples, 85 have been deemed valid, based on a comparison between calculated total dissolved solids of the brine and lithium concentrations (Figure 36). The low outlier sample, containing 130,000 mg/L TDS, has a complicated well completion history including comingled production with the Nisku. As such, the sample is excluded from the analysis as the TDS marks it as unrepresentative of the Leduc formation.

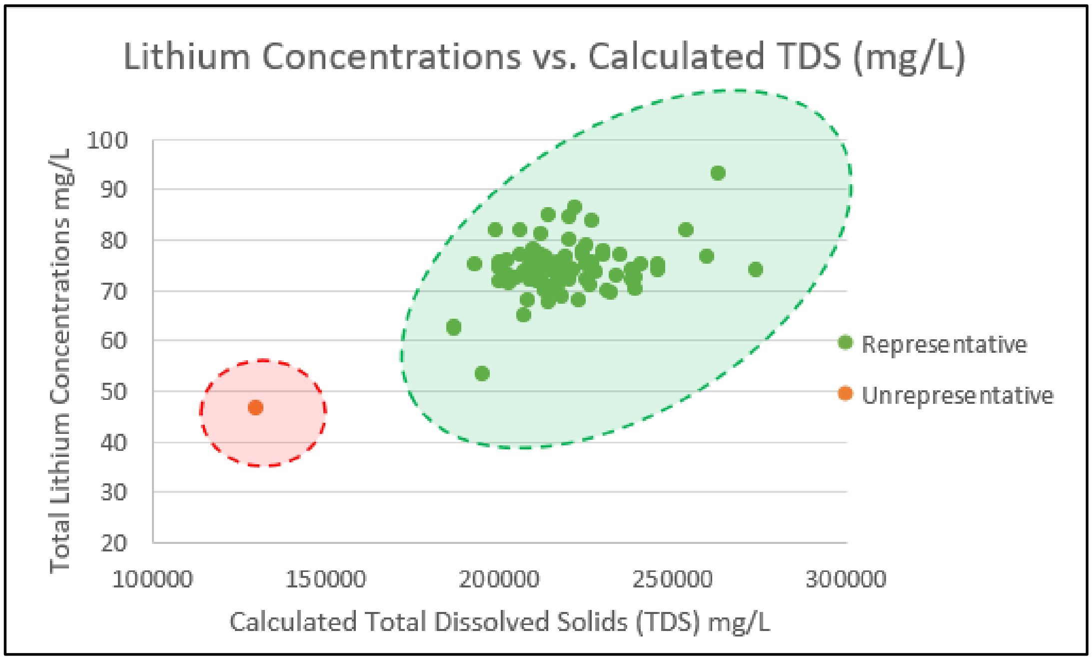

Figure 36: Sampled Lithium Concentrations Plotted Against TDS

Average brine chemistries from routine and trace metals scan analysis in the BD is presented in Table 7.

Table 7: Average Chemical Analyses Across the BD
List of major cations and anions samples and P50 Lithium concentration (mg/L)

Measurement	P50
Trace Metals Analysis	
Total Arsenic (mg/L)	2
Total Barium (mg/L)	1.46
Total Boron (mg/L)	275.5
Total Lithium (mg/L)	74.7
Total Manganese (mg/L)	0.18
Total Silicon (mg/L)	11.6
Total Strontium (mg/L)	956.00
Total Calcium (mg/L)	21,700
Total Magnesium (mg/L)	3,037
Total Sodium (mg/L)	49,000
Total Potassium (mg/L)	6,530
Routine Water Analysis	
pH	7.04
Alkalinity (Total as $CaCO_3$) (mg/L)	424
Bicarbonate (HCO_3) (mg/L)	515.5
Conductivity (µS/cm)	336,000
Dissolved Chloride (Cl) (mg/L)	133,000
Fluoride (F) (mg/L)	3.0
Dissolved Sulphate (SO_4) (mg/L)	374

Dissolved Calcium (Ca) (mg/L)	21,350
Dissolved Magnesium (Mg) (mg/L)	2,910
Dissolved Sodium (Na) (mg/L)	49,500
Dissolved Potassium (K) (mg/L)	6,240
Dissolved Iron (Fe) (mg/L)	0.4
Dissolved Manganese (Mn) (mg/L)	0.15
Calculated Total Dissolved Solids (mg/L)	217,000
Sodium Adsorption Ratio	83.20
Hardness (mg $CaCO_3$/L)	65,650
Total Suspended Solids (mg/L)	333

11.5. Temporal Variation

Sampling to date includes samples from 44 individual wells, with 4 or more repeat samples collected at several locations. A graphical summary of lithium concentration measurements in 3 wells with repeat samples is shown in Figure 37. All analytical results fall within acceptable limits as prescribed by the laboratory. These graphs suggest lithium concentrations remain steady in a relatively narrow P90 to P10 distribution over time in the BD.

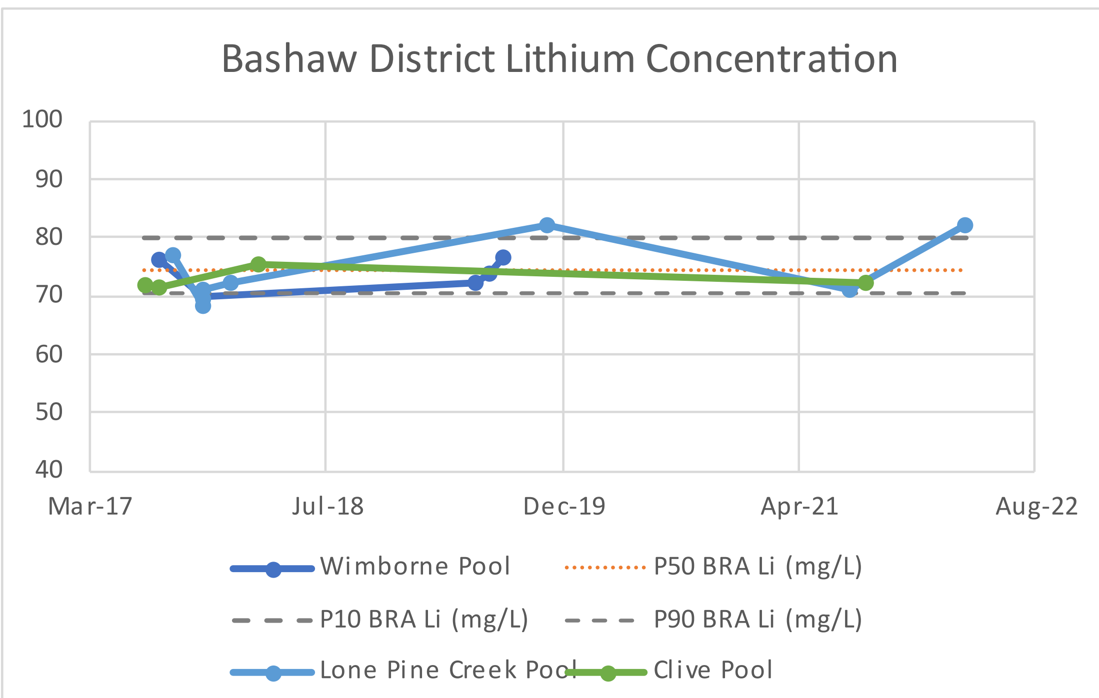

Figure 37: Lithium Concentrations in the Bashaw District Over Time

12. Data Verification

12.1. Lithium Grade Sampling

One component of the Quality Assurance program was for a QP to witness sample collection in the field. Alex Haluszka, of Matrix Solutions Inc, having reviewed the field sampling Standard Operating Procedure (SOP) and the Laboratory Testing SOP (Appendix F) developed by E3 to achieve consistent and accurate sample collection and analysis, witnessed the sampling and authenticated the SOP and COC, for the 2022 sampling program and the 2022 drill program.

BV employees collected samples as described in Section 9.1 from a 3-phase test separator facility on April 28th, 2022. During the observation, BV employees demonstrated a competency of the E3 SOP and executed sampling accordingly. The site was in the southern area of the BD, within the Lone Pine Creek hydrocarbon pool, and the produced water sampled flowed from the 100/10-29-030-27W4. Samples were delivered to AGAT for degassing, trace metal and routine water analyses by a courier (Rebel Hotshot Courier Services) upon the completion of the sampling program.

The QP has additionally reviewed the Quality Assurance/Quality Control results provided by E3 and reviewed the reports provided for each lithium sample by the laboratory. The QP is satisfied that data presented in this report is adequate for the purposes of calculating an indicated and measured resource.

Starting in 2019, Maxxam Laboratories now operates as Bureau Veritas Laboratories and E3 continued to work with the same field staff for sampling programs in 2022 (Figure 38).

Figure 38: Chain of Custody by BV Labs

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

12.2. Flow Test

Alex Haluszka, of Matrix Solutions Inc, witnessed the flow test during a site visit on September 15th, 2022, and reviewed the validated and authenticated report provided by IHS Markit. The site visit included observation of the flow rates, discussions with the Schlumberger field engineer who was operating the electronic submersible pump (ESP), and discussions with Grant Production Testing personnel who were providing quality control and assurance on the rate measurements.

13. Mineral Processing and Metallurgical Testing

E3 is focusing on integrating well-known and understood processes into an integrated flowsheet for producing battery-grade lithium hydroxide monohydrate (LHM). This means implementing low-risk, commercially available processes and technologies to move quickly through the PFS and subsequent project development phases to minimize the design schedule. This strategy also aims to maximize the likelihood of successful commercial operations as early as possible.

Metallurgical testing has focused on selectively recovering lithium while rejecting other cations in the Leduc Reservoir brines using E3's Direct Lithium Extraction (DLE) technology. The preliminary metallurgical information presented in this report is based on tests completed from 2016 to 2023. The initial test work from 2016 to 2018 was completed at the University of Alberta. From 2018 through 2020, bench-scale test work was completed by GreenCentre Canada, an independent sustainable chemistry and advanced materials laboratory in Kingston, Ontario. All testing from Q1 2021 onwards has been completed by E3 personnel at the E3 lab facility in Calgary, Alberta, and at contractors' testing facilities.

13.1. Continued Development and Testing

Since the release of E3's Bashaw District Project Lithium Resource Estimate NI 43-101 Technical Report in August 2022, E3 has achieved the following advancements:

- For its proprietary ion exchange sorbent material, with very high selectivity for lithium above all other cations in the brine, E3 has successfully completed small-scale sorbent production pilot programs replicating commercial-scale continuous operations. This is an important step for progressing to larger-scale pilot programs to scale up sorbent production further.
- E3 has continued benchmarking its proprietary ion exchange sorbent material against other commercially available sorbents. This program aims to maximize lithium recovery, selectivity, loading capacity, and sorbent lifespan.
- E3 has executed desktop studies internally and with 3rd parties that evaluated a wide range of flowsheets for the lithium refining process downstream of DLE to produce LHM.

Final decisions regarding flowsheet selection have not yet been made and will align with E3's focus and approach as outlined above. Further details will be released in a subsequent NI-43101 report, as the focus of this NI-43-101 report is to update the resource statement.

13.2. Direct Lithium Extraction Testing

All DLE test work has been completed using brine sourced from the Leduc Reservoir. 20m^3 of brine was first collected in 2019 from the water leg of a 3-phase separator on an operating oil and gas well. An additional 60 m^3 of brine was collected in 2022 from E3's (and Alberta's) first well drilled specifically for lithium extraction.

Prior to storage, the brine was mechanically sweetened by AMGAS using their proprietary CLEAR[iv] technology to remove H_2S without introducing chemicals to the brine. Sample analysis has been conducted by both E3 and independent and quality-certified laboratories.

The DLE test work is completed at elevated temperatures (70°C) to match the expected brine temperature from the reservoir to the central processing facility.

Continued DLE testing has demonstrated the technical and economic viability of DLE technology for selectively recovering lithium from E3's Clearwater project. Further details will be released in a subsequent NI-43101 report.

13.3. From Lab to Pilot Scale

E3 design work and planning is well underway for a DLE field pilot for Q3 2023. Brine for the pilot will be produced from E3's first lithium well in the Leduc Reservoir, drilled in the summer of 2022. The sour brine will be treated at the surface using AMGAS CLEAR[iv] technology, and the sweet brine will be processed through the DLE skid. Lithium concentrate will be collected for downstream testing, and the spent brine will be disposed of using a well-disposal service. E3 and third-party ISO-certified labs will analyze samples to measure the performance of the DLE system.

E3 is also looking to complete testing of the Post-DLE circuit by Q3-Q4 2023 to validate the design, produce battery-grade LHM for marketing purposes, and generate design data. All the process steps in the post-DLE flowsheet are standard, well-proven technologies to reduce risks.

14. Mineral Resource Estimates

The resource estimate is based on reservoir geometries and properties populated in a 3D geological and reservoir model developed using Petrel™[lxviii]. Petrel™ is a commercial software platform that integrates geological and reservoir data, which E3 used to estimate volumetrics and evaluate grade distribution. The geological model included the following reservoir characteristics: area geometry, structure, thickness, porosity, permeability, and lithium concentrations. The 3D geological model was utilized to geostatistically simulate and evaluate scenarios of connected porosity in the reservoir that comprise the resource volume in the model domain. The mineral resource estimate was developed from a considerable amount of data collected by E3 over the past six years, as well as data compiled from the oil and gas industry, which is made public as a matter of normal practice by the Government of Alberta.

Publicly available grade data (See section 6.5) was not used directly in the grade calculation but informed the understanding of grade continuity.

14.1. Indicated and Measured Methodology

The methodology used for the indicated and measured mineral resource estimates has evolved in keeping with the increased understanding of the Leduc resource across the BD. Additional data collection, geological data integration, and analysis enabled significant changes from the inferred methodology, described below.

14.1.1. Changes from Inferred Methodology

The fundamental changes between the methodology used in this Indicated and Measured report, and previous Inferred reports, is the use of the 3D geological model described above. The model enabled variogram-informed kriging for thickness and sequential gaussian simulation to populate 50 equiprobable three-dimensional realizations for porosity. In addition to the modelling, updated statistical analyses of permeability (based on porosity-permeability correlations) and lithium grade (using variography and descriptive statistics) was completed. A comparison of parameters showing the change, if any, from the inferred methodology to the indicated and measured methodology, is shown in Table 8.

The model allowed for quantification of 3D spatially connected volumes, described in Petrel as "geobodies", above a given porosity cut-off and connected to a lithium grade sample location. Connected cells that are separated from other areas of connected cells are modelled as unique geobodies and identified as such in the model outputs.

Table 8: Comparison of Parameters used in Inferred vs Indicated & Measured Methodologies

Parameter	Change	Rationale for Refined I&M Approach
Area Geometry	No change (Fixed area based on geological mapping)	Shape and extent of the Leduc Formation in the BD is generally accepted; no additional data gathered near the edges of the BD
Structure & Thickness	• Inferred: Single P50 thickness applied across BD • Indicated & Measured: New surfaces generated in the Petrel model for the Leduc and Cooking Lake formations; spatially variable mapped thickness of the formation captured at each grid column	Using a variogram-informed kriging reduces uncertainty around structure and thickness
Porosity	• Inferred: Single P50 effective porosity applied across BD; effective porosity was estimated by multiplying P50 total porosity by the P50 net to gross ratio. • Indicated & Measured: Total vs. effective porosity was directly	Significantly reduced uncertainty in historical porosity datasets after having directly measured total vs. effective porosity in core samples; using the porosity variograms, sequential gaussian simulation of 50 equiprobable realizations quantified uncertainty in

	measured by E3 from core samples in BD; this information was used to validate historical estimates of effective porosity; declustered effective porosity data (see 14.1.3) and inclusion of porosity-depth relationship represents full range of potential effective porosities captured at each grid cell	porosity and connectivity providing confidence in the representativeness of the P50 porosity distribution used to update the resource estimate
Permeability	• Inferred: 10 mD permeability was associated with producible resource volume and was associated to a 2% porosity based on "Flow Zone Indicator" analysis • Indicated & Measured: Updated porosity/permeability relationship was interpreted to indicate a high confidence that 6% porosity could be associated with a producible resource volume and 2% a moderate confidence.	Permeability is not a direct input to the resource estimate, but must be taken into account as part of the "Reasonable Prospect for Eventual Economic Extraction". Upon further analysis the FZI approach was deemed to have less certainty than the cross-plot approach to relate porosity to permeability.
Lithium Grade	• No change (P50 concentration used as input)	Additional data in the lagoon areas increased confidence in grade continuity across the BD and vertically in the Leduc. Statistical analysis of lateral and vertical lithium concentration samples further validated the use of a single P50 concentration applied across BD
Fluid saturation	• No change (Fixed value of 99% used as input)	Direct measurement of dissolved gas saturation in the brine from fluid samples collected at reservoir conditions increases confidence in the input value used

14.1.2. New Data

New Data from E3's 2022 drill program (Table 9) supplemented the existing public data set (Table 10), providing increased confidence in the mineral resource estimate by targeting locations within the BD that were previously under-represented by the historical data set, and validating the publicly available core testing with core analysis conducted directly under the care and control of E3. E3's program was also designed to evaluate parameters that could not be readily evaluated from the existing public dataset which included: vertical distribution of lithium grade in the reservoir, effective porosity, and irreducible water saturation.

Table 9: New data supporting improved resource estimation methodology

Data Source	Contribution to Resource Estimate
E3's 2022 Flow Test	• Pressure validation; brine grade and chemistry analysis; permeability estimation; flow system continuity
E3's 2022 Evaluation Well Program	• Core analysis: Porosity (total and effective); permeability measurements; facies descriptions; lithium concentrations • Downhole wireline logs: Formation tops, depths, and thicknesses; lithology and facies interpretations; porosity (total and effective) • Pressurized Sample Analyses: Water analysis, gas/water ratio (GWR), compositional analysis of flashed gas • Special Core Analysis: Centrifuge Test for Irreducible Water Saturation • Crushed Rock Analysis: Porosity (total and effective)

Table 10: Existing data supporting resource estimation

Data Source	Contribution to Resource Estimate
Public Well Data (logs, core, drill stem tests)	• Downhole wireline logs: Formation tops, depths, and thicknesses; lithology and facies interpretations; porosity (total and effective) • Core analysis from 330 cored wells: Porosity (total and effective); facies descriptions • 327 Drill Stem Tests: pressure, water quality, and permeability measurements
Historical Production and Injection Volumes (hydrocarbons and brine)	• Regional pressure measurements supporting continuity and rate data supporting producibility and injectivity from 593 wells
E3's 2017-2022 Sampling Programs	• Lithium concentrations

14.1.3. New Analyses

Sequential Gaussian Simulation

The Petrel software was used to integrate all geological, petrophysical and reservoir data into a three-dimensional framework. Porosities were assigned to each individual grid block within the model based on field data and variogram-guided geostatistical simulations, also using Petrel. The geostistical simulation method used for effective porosity was sequential gaussian simulation (SGS). With the SGS method, the measured data points are honoured as well as the mean and standard deviation of measured effective porosity dataset (after upscaling to the model grid scale size). Following a randomised path through the grid, kriging is used to estimate/simulate the mean porosity and standard deviation based on the local data and variogram and assign values to each node. Within each simulation using SGS the expected heterogeneity represented by the measured data is better represented than when using deterministic kriging. Additionally, multiple simulations were performed to evaluate the parameter uncertainty in porosity and the connected porosity volume (which was deemed to be a key parameter to constrain for the resource estimate). Fifty unique three-dimensional realizations of porosity were completed to quantitatively evaluate the uncertainty in these parameters, with each one of these realizations honouring the data and the variogram.

Specific Yield, Total vs Effective Porosity, and Irreducible Water Saturation

Current CIM guidance for lithium brines indicates that specific yield should be utilized for resource estimates (CIM 2012)[lxix]. This guidance was developed based on salar resources, and based on the following discussion, we believe that for deep, confined, carbonate reservoirs where pressure in the reservoir will be maintained using re-injection, using recoverable volume based on effective porosity and not excluding irreducible water saturation in place of specific yield is appropriate.

Specific yield is defined as the amount of water that drains from the connected pores under gravitational forces (Woessner and Poeter 2020[lxx]) and an analogous petroleum geological term would be "recoverable volume", although reservoir drive mechanisms replace gravitational forces. Gravitational forces are not the driving mechanism for deep, confined reservoirs; instead, reservoir pressure is the dominating force. Reservoir pressures will be maintained during production, which means that the fluid level will not drop, and therefore the formation will not be dewatered and pressure balance will be maintained. This means that the reservoir porosity will remain fully saturated during production, unlike in the definition of specific yield which replaces brine saturation with air. Furthermore, in this scenario total system compressibility (i.e. specific storage), is not a controlling factor on the producible volume because the reservoir pressure is being maintained.

Crushed Rock Analysis to evaluate Total vs Effective Porosity

For this report recoverable volume is based on effective porosity over total porosity, as total porosity measurements include disconnected pores which are not accessible for fluid flow. To evaluate the difference between total and effective porosity, and to help provide additional confidence whether total or effective porosity was being provided by a given dataset, a crushed rock analysis was performed on 3 core plugs collected from E3's test well program.

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

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

Wireline logs estimate total porosity (all fluid saturated pore space) based on specific physical measurements further described below in Section 14.2.3. Effective porosity can be estimated from wireline logs using several documented techniques which is further discussed below.

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

The resource estimate uses effective porosity.

Test to evaluate Irreducible Water Saturation

As described above, the term effective porosity is used both in hydrogeology and the oil and gas industry to represent connected pores, although there is some inconsistency in oil and gas as to whether effective porosity does or does not include irreducible water (API 1998[xv]).

E3 completed an assessment of irreducible water on core samples collected from the test wells. Irreducible water was evaluated by weighing the dry core plugs, fully saturating them with synthetic brine water, flooding them with lithium-void synthetic brine, and then drying them again. The difference in density between the initial sample and the dried sample was interpreted to represent the irreducible water saturation. Irreducible water was measured at 4.7%.

The resource estimate does not exclude irreducible water from the recoverable volume on the following basis. While there is a physical mechanism controlling fluid adherence to grains (typically clays), the rationale for excluding irreducible water saturation is driven by differences in fluid wettability in multi-phase systems, resulting in preferential production or retention of certain fluid types. The resource area of interest (the Leduc reservoir in the BD) is almost entirely water saturated, with dissolved gas anticipated to stay in solution as the reservoir pressure will be maintained above the bubble point. The resource can be treated as a single-phase system that is fully water saturated. In single-phase system that is fully saturated, irreducible water saturation be safely ignored (Van Rosenberg 1956; Clerke 2008; Coasts & Smith 1964).

In the analysis of irreducible water, E3 fully flooded the pore volume with lithium depleted brines for a total of 40 pore volumes. Additional analysis of this information will be completed as part of future studies to evaluate lithium recovery using the depleted brine reinjection. Using this information, a lithium recovery factor will be evaluated as a modifying factor that will be applied to mineral reserves.

Updated Petrophysical Interpretation

The petrophysical model used as an input into the updated geological model has been revised from the previous technical report. The inferred resource used a total of 72 wells with LAS curves for the petrophysical analysis, and included a number of logs that did not contain the full suite of logs (porosity, gamma, resistivity). This includes wells where only sonic logs were available, which increases uncertainty in the analysis as the porosity interpretation cannot be bolstered by additional curve interpretation.

The revised petrophysical model is based on 57 wells with LAS curves, to eliminate wells without full coverage of the Leduc Reservoir over the Bashaw area. Restricting the petrophysical model inputs to wells with full log suite coverage increases confidence in the model by allowing independent methods to be combined for a more representative analysis (e.g. interpreting porosity from the density log and the neutron log). Additionally, the revised petrophysical model was cross-checked against the core porosity data set, demonstrating alignment between the two sources of porosity data.

Updated Porosity-Permeability Correlation

Linear regression analysis was done on the core data to evaluate the relationship between porosity and permeability. A critical evaluation of the porosity/permeability relationship within the Leduc Formation determined that it was highly variable and complicated by sedimentological facies, diagenetic overprinting, fractures and core analysis limitations. While linear regression is also subject to uncertainty, at this time the authors feel that the uncertainty is lower than the uncertainty associated with the FZI methodology applied for the Inferred Resource.

The regression model is illustrated in Figure 39. There are a wide range of permeabilities that are associated with a given porosity value due to the variability in fracturing of the reservoir and variability in matrix porosity type. Petrophysical estimates of porosity reflect the dual porosity and permeability system where portions of the reservoir are dominated by fracture porosity and permeability, and portions of the reservoir are dominated by intercrystalline matrix porosity created by replacement sucrosic dolomite. Therefore, Kmax data is often biased high and K90 data is considered more representative of matrix permeability. Further discussion on this topic is presented in section 14.2.4 below.

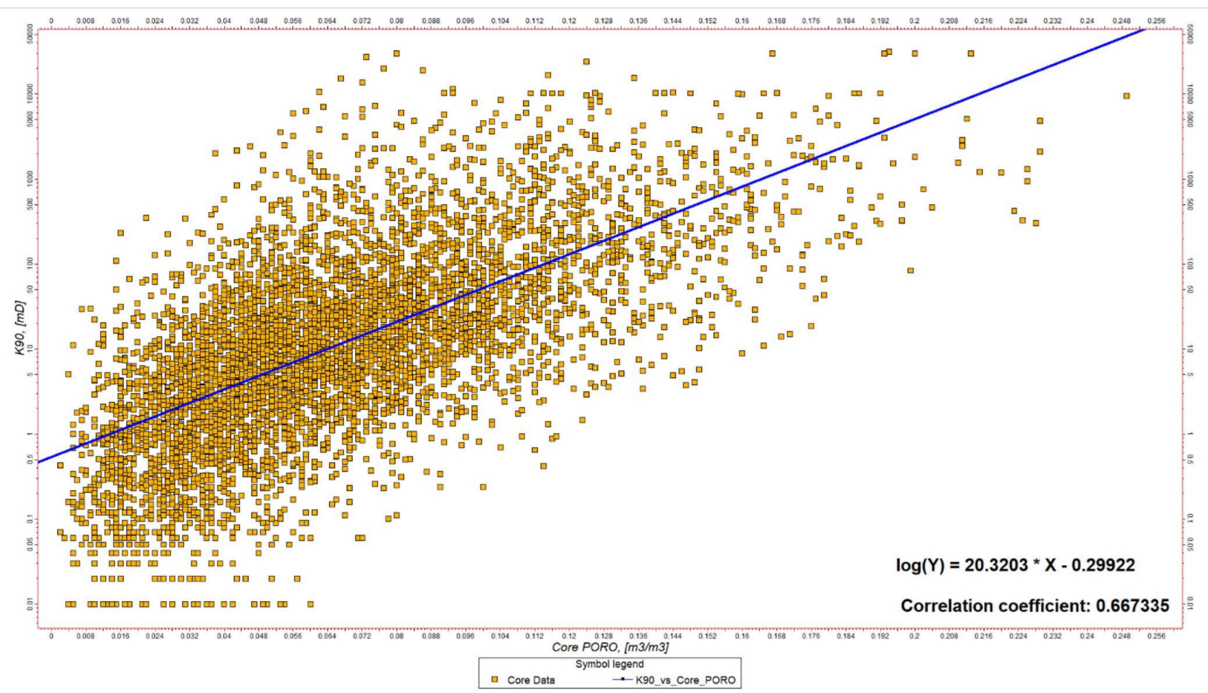

Figure 39: Cross plot of the Porosity-Permeability Relationship

14.2. Key Parameters

This section describes key data sets used to determine values for key reservoir parameters, and their contribution to the resource estimate.

14.2.1. Area Geometry

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

The boundary of the Leduc reef complex is challenging to define in the study area for three main reasons; the bias in well control preferentially in the carbonate reef complex with only a few minor penetrations that define the margin to basin transition; extensive dolomitization tends to obliterate the primary textures, making it difficult to recognize typical facies, diagenetic fabrics and organisms characteristic of the margin (e.g. frame builders and fibrous marine cement); and limited seismic data. As such, the "zero-edge" for the Leduc Resource Area is defined based on the change from high porosity Leduc carbonate reef complex from the surrounding low porosity carbonate muds and shales of the deep-water basin sediments occurring in the Ireton and Duvernay Formations. In the absence of well data, and seismic interpretations existing industry-standard Leduc edge interpretations were consulted (Potma et al., 2001[ii]; Hearn and Rostron, 1997[lxxii]; Hearn et al. 2011; Potma and Weissenberger, 2013[lxxiii]; Mossop and Shetsen, 1994[lxxiv]; GeoScout Devonian Subcrop, 2022[lxxv]). The local and regional geological context was also taken into consideration when making interpretations.

14.2.2. Structure and Thickness

Geological interpretation was completed by E3 via the vetting and selection of geologic formation tops over the Leduc, and Cooking Lake formations. The Leduc top was selected at the base of the Ireton shale (Figure 12), and the Cooking Lake was selected using a regional shale at the base of the Leduc, and a combination of isopach thickness, and the gamma log where the regional shale was less distinguishable (discussed in section 7). These formations were used for mapping structure and thickness for the Leduc, and Cooking Lake formations. The geologic data set used to construct the maps was comprised of 2397 wells with Leduc structure tops (Figure 40), 101 wells with Cooking Lake structure tops (Figure 41).

The model uses ordinary kriging for structure and thickness for the Leduc across the BD. This methodology is appropriate for spatially continuous data and is a deterministic method with a single value result. The result is based on a spatial correlation between data points.

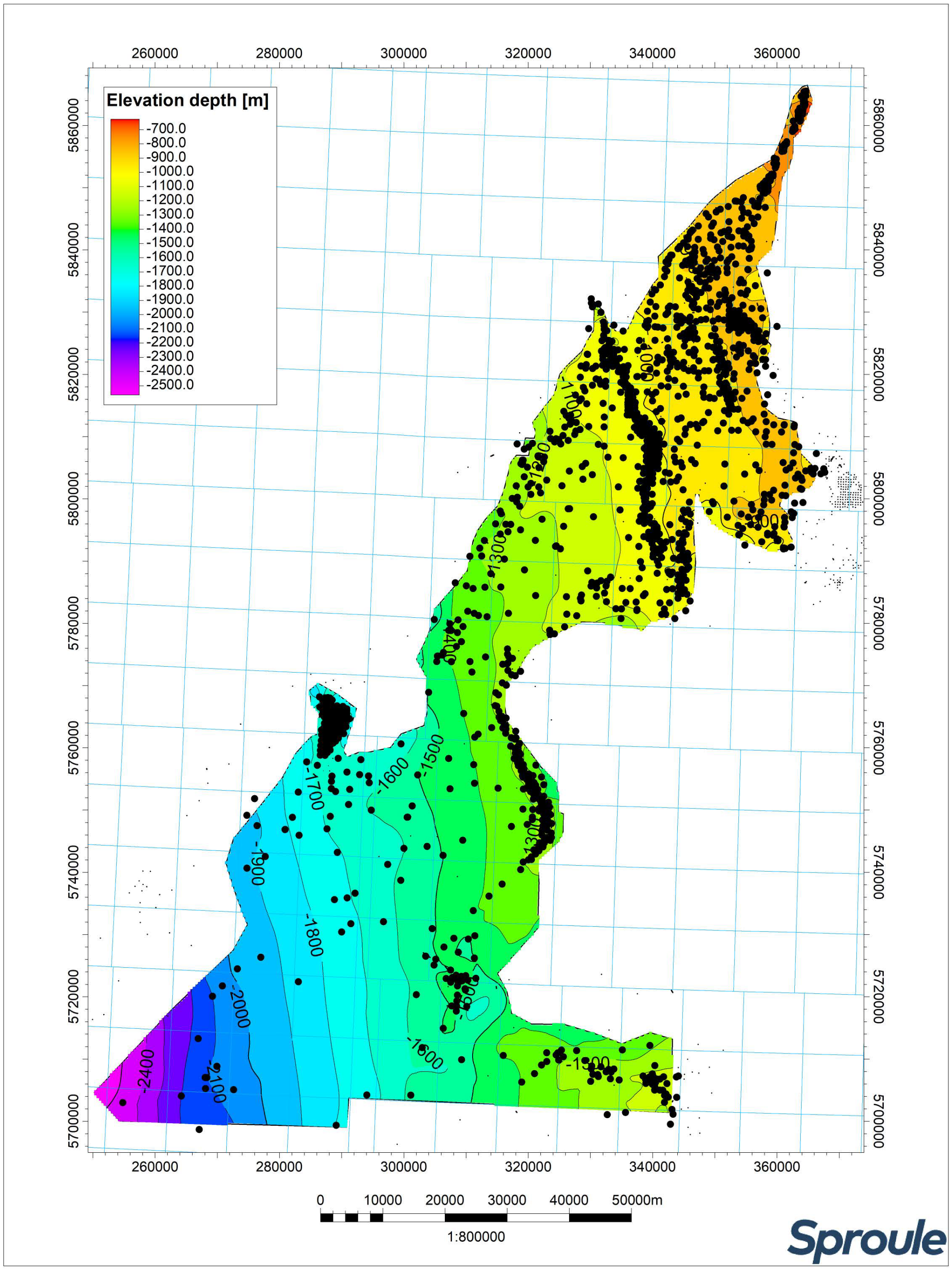

Figure 40: Structure Top of the Leduc

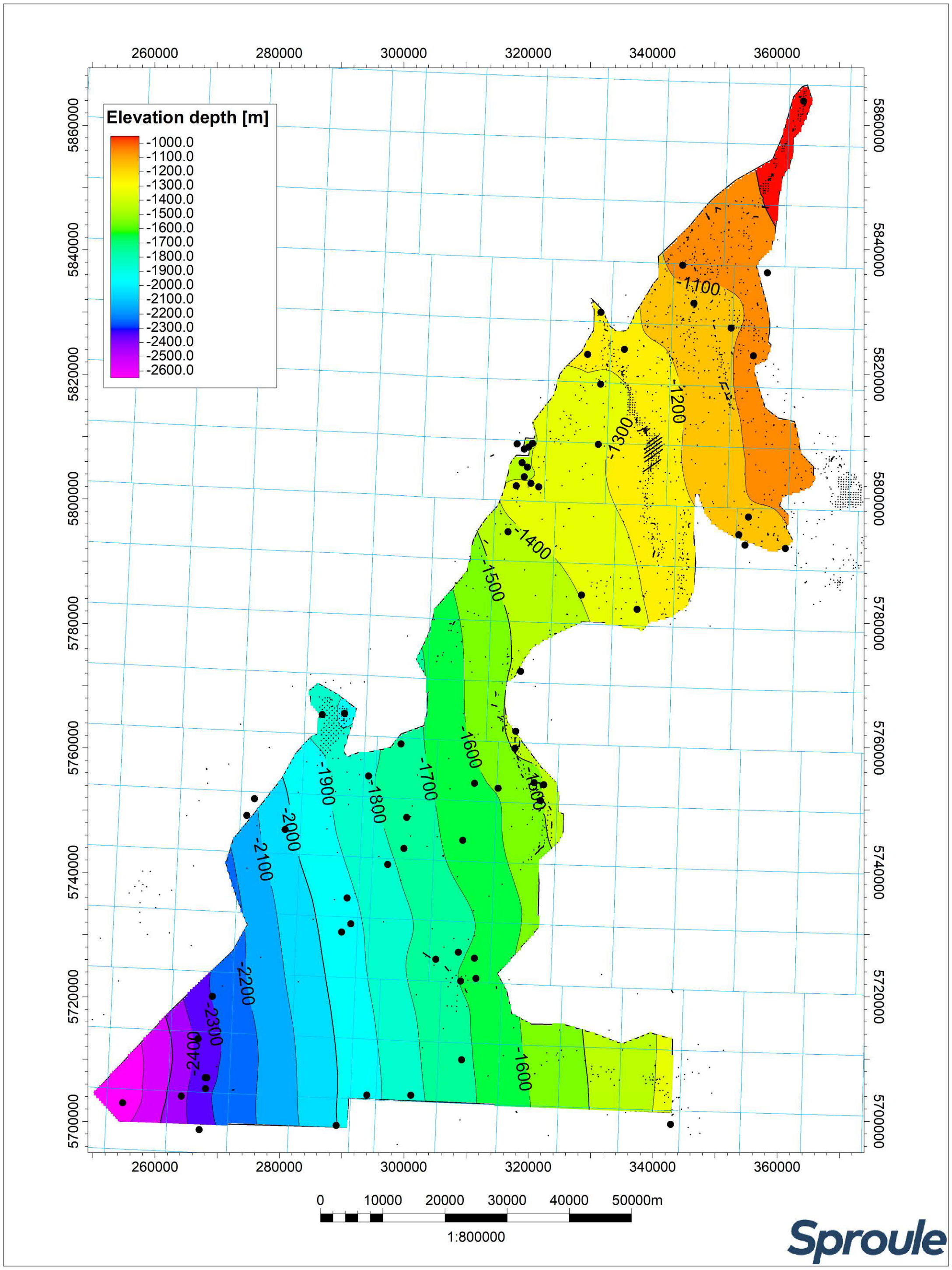

Figure 41: Structure Top of the Cooking Lake

The geological tops and original maps were used as the framework inputs for the 3D geological model. New surfaces were imported in the Petrel model for the Leduc and Cooking Lake formations. The model was constructed of individual cell blocks 400m x 400m x 0.5m in size. This grid cell size was deemed appropriate to honour the potential heterogeneity in geological properties informed by the input data (i.e. well logs, core, and seismic data) and also be manageable computationally for completing additional analysis and future flow simulations. The model represents the entire range of thicknesses and accounts for the thinner edges and the thickest part of the reef complex (Figure 42).

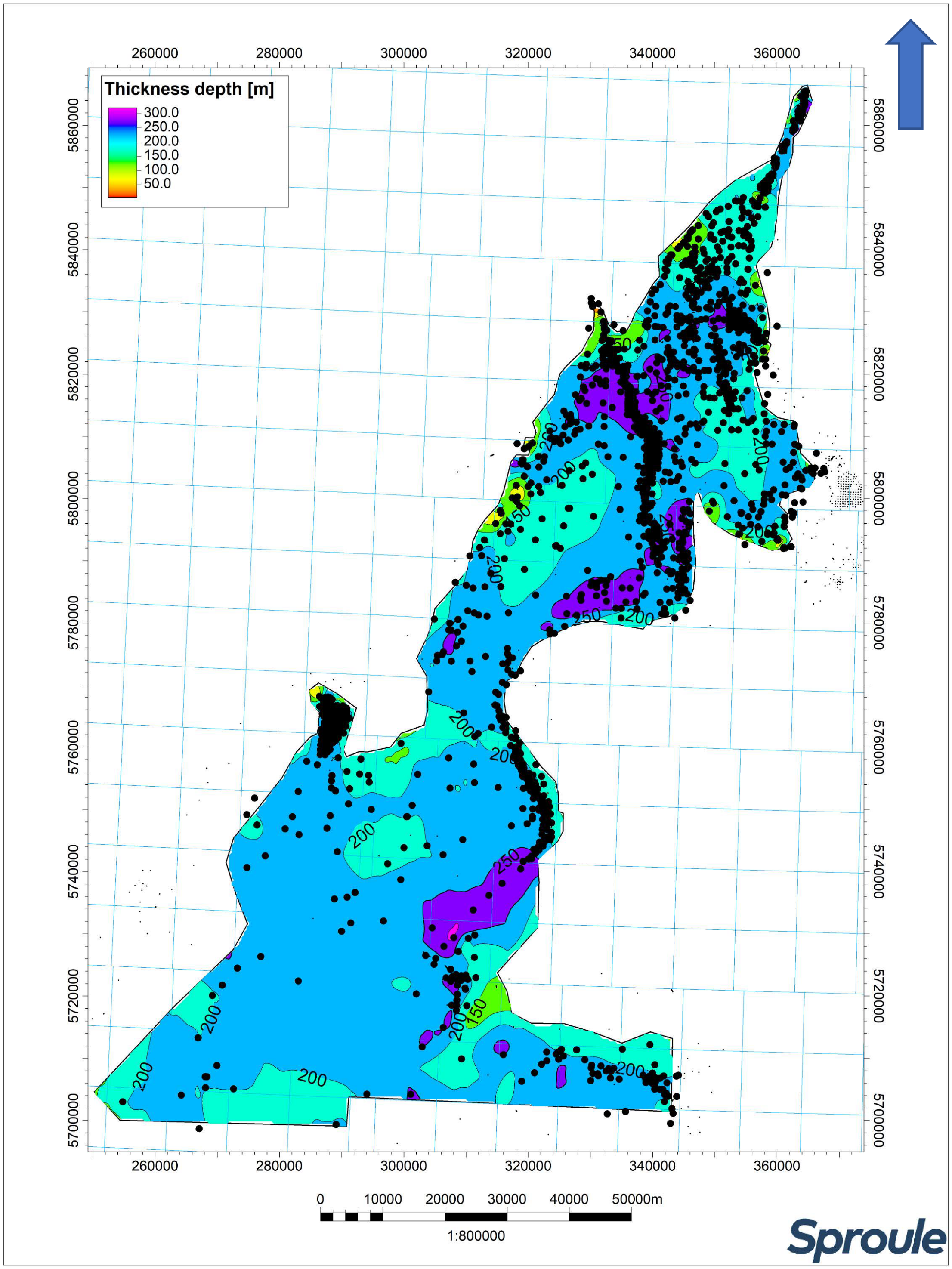

Figure 42: Gross Isopach Map of the Leduc

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

14.2.3. Porosity

Multiple techniques were used to evaluate the porosity of the reservoir. Porosity estimates of lithofacies units in the BD were informed by facies-based porosity estimates published by Atchley et al. (2006)[xxx] and further constrained by core plug measurements and wireline data. Wireline Photoelectric (PE) curve data was used to determine lithology, specifically in this case between limestone and dolomite (refer to type log to see lithology shift: Figure 12) (Kennedy M.C., 2002)[lxxvi]. This distinction is important to the characterization of porosity as dolomite typically has a higher porosity than limestone. The majority of the porosity measurements were determined using petroleum industry standard neutron/density open hole logs, which measure hydrogen concentration and electron density, respectively (American Association of Petroleum Geologists, 2017[xiii]).

There are industry standard methods to estimate effective porosity from wireline logs. In this study, effective porosity was estimated by using a shale volume (Vshale) correction applied from the gamma ray log. This assumes that clay content would be the major influence total vs. effective porosity, which has not been confirmed for the Leduc reservoir and introduced some uncertainty that log derived effective porosity represents the true formation effective porosity.

There are multiple methods for measuring porosity from core samples in the oil and gas industry, and some evaluate effective porosity while some evaluate total porosity (API 1998[xv]). The most common routine core porosity analysis used in Western Canada are completed on dried samples and utilize injection of helium gas to estimate the connected porosity using Boyle's Law. This would be an estimate of effective porosity. In the Inferred Resource assessment completed for the BD, uncertainty in whether all of the historical core analysis derived from public databases used this methodology, the core analysis results were treated as total porosity measurements to be conservative.

Porosity data from core and logs were incorporated into the Petrel model. Separate inputs were made for both total and effective porosity datasets. The total porosity dataset is derived directly from the well logs, while the effective porosity dataset leverages corrected log porosity (using VShale) as well as the core porosity. The resource estimate uses a cut-off applied to the effective porosity.

The data was declustered and a corrected porosity histogram was developed (Figure 43). Data declustering is a standard geostatistical tool used to remove bias from a given data set[lxxvii]. During the declustering, each data point is assigned with a specific weight reflecting the relative percentage of reservoir area or volume which this data represents[lxxviii]. The data points remain unchanged, but the contribution to the modelled histogram and mean changes, and depends on the assigned weight. This methodology reduces the weighting in the higher-energy areas of the dataset, resulting in a lower P50 value than in the inferred report.

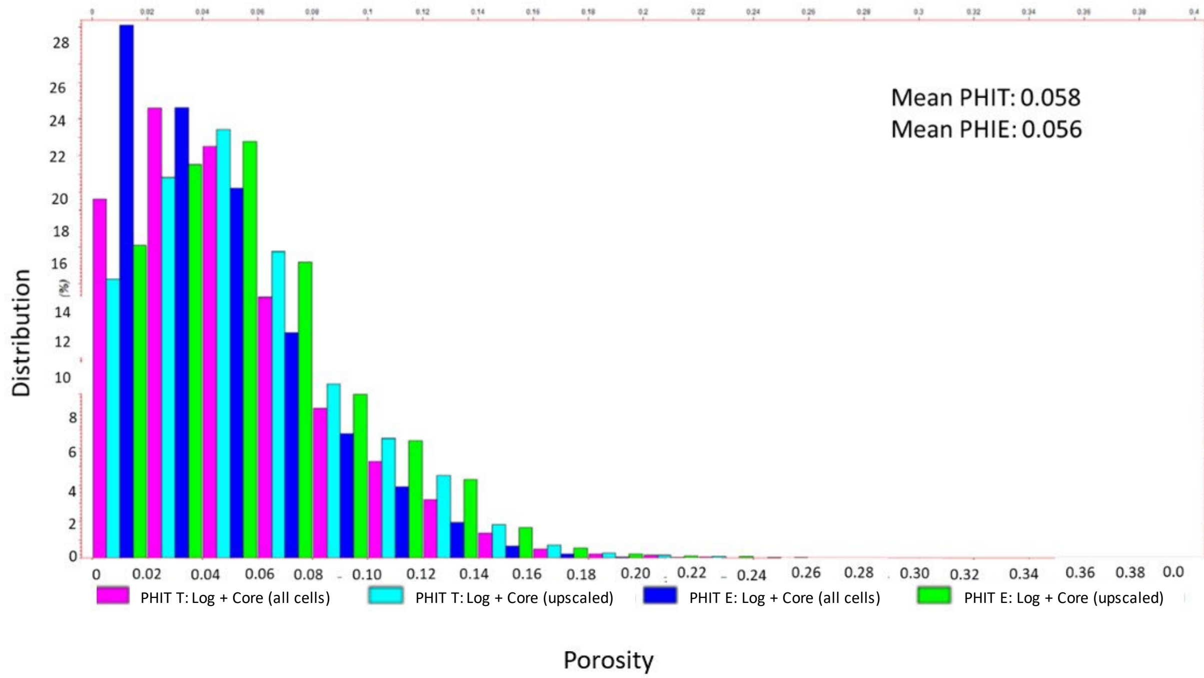

Figure 43: Porosity Histogram from Core and Log Data

Additionally, a porosity-depth relationship was observed in the data and was incorporated into the model (Figure 44). This supports the current conceptual understanding of the reservoir, as the formation transitions from more porous dolomite to less porous limestone towards the base of the Leduc and into the Cooking Lake formation. Data for the porosity modeling includes both dolomite and limestone portions of the reservoir with the majority of the core data coming from dolomitized portions of the Leduc, and the log data coming from both dolomitized and limestone parts of the reservoir.

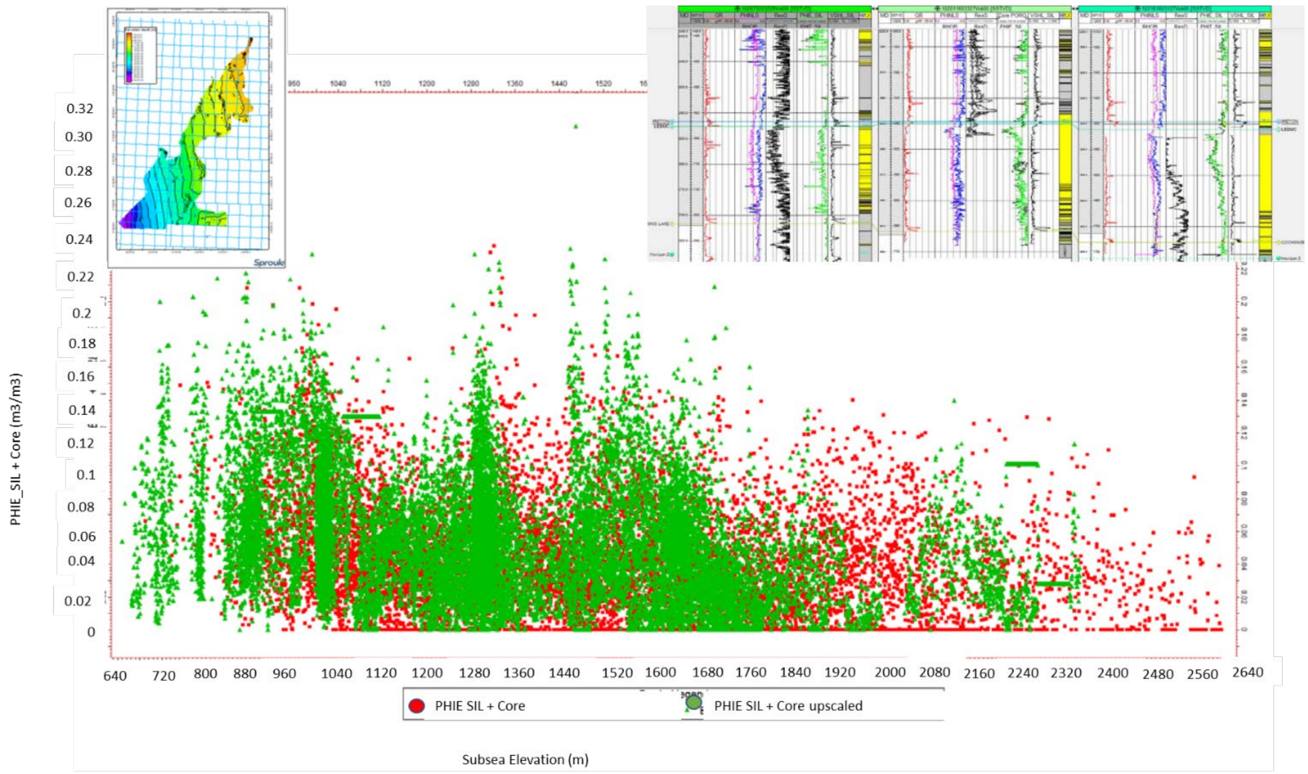

Figure 44: Declustered porosity data showing porosity-depth relationship in the geological model

The data declustering shifted the input P50 effective porosity lower to 5.6% from logs and core data when compared to the 6.63% P50 value used in the inferred report. The modeled P50 effective porosity is 4.2% overall, and 5.9% above the 2% porosity cut-off. The modelled P50 effective porosity was influenced by both the declustering completed on the input data and the porosity-depth reduction which was incorporated into the model.

Net effective porosity thickness is the total thickness of the reservoir with effective porosity above a porosity cut-off. A porosity cut-off is typically selected to represent the lower productive limit of a formation, below which the rock is not expected to materially contribute to fluid production. Two separate porosity cut-offs were applied to the indicated and measured resource estimates, to represent a differing level of confidence in what porosity values can be confidently associated with permeability values that would readily produce brine:

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

A fence diagram through the geomodel (from a single realization) showing the 3D distribution of the porosity cut-offs is shown in Figure 45.

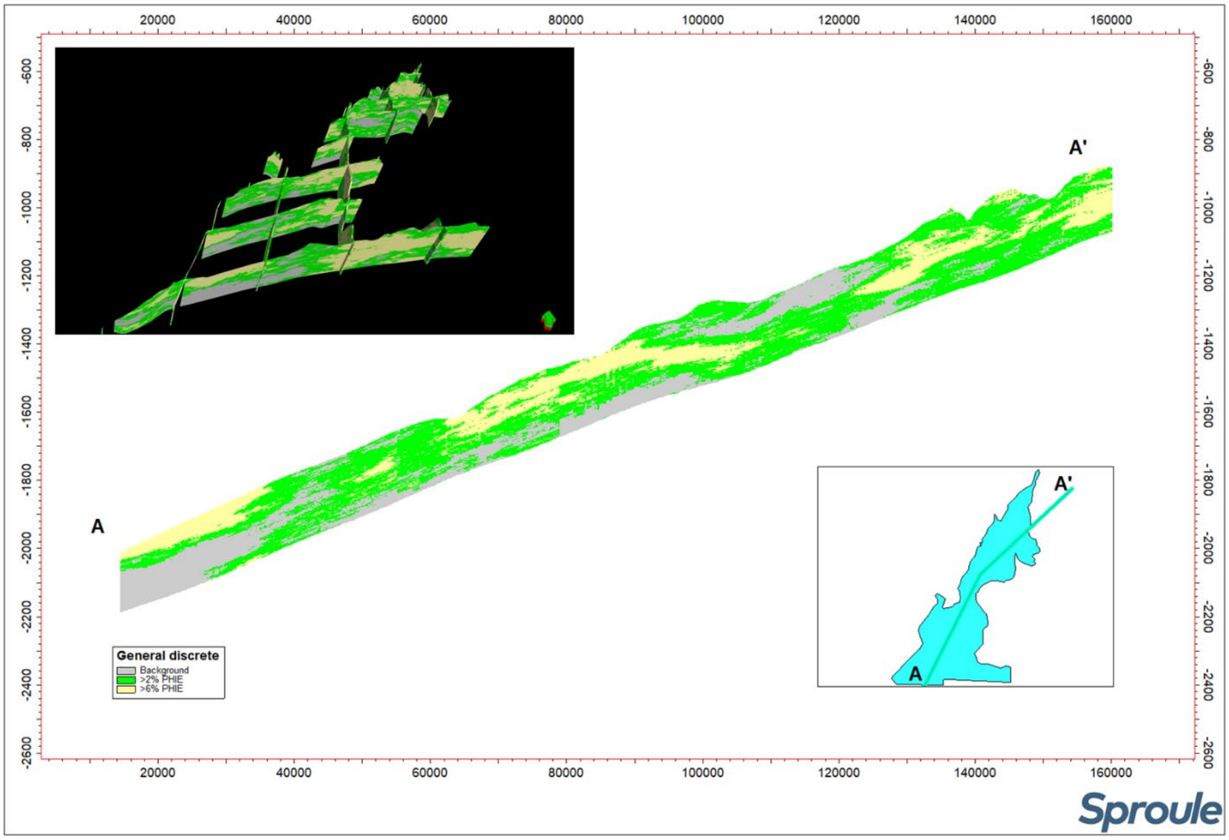

Figure 45: Fence diagram illustrating distribution of porosity cut-offs across the Bashaw District

14.2.4. Permeability

Multiple techniques were used to evaluate the reservoir permeability, as shown in Table 11:

Table 11: Permeability Data Sources and Range of Values

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

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

DST analysis was completed by Melange Geoscience Inc. on a subset of what was considered high-quality DST data. Pressure build-up curves were analyzed on 5 DSTs in the Leduc Formation in the BD. DSTs were performed over reservoir classified as Facies-1, reef flat to reef margin and Facies-2, reef interior to open lagoon. This analysis was performed in 2019 and is considered valid and unchanged at this time.

The core plug permeabilities reflect high quality estimates of permeability on a sub-wellbore-scale (cm-scale) and the DST derived permeabilities reflect high quality estimates of permeability on a near wellbore-scale (m-scale to 10s of m-scale). Both historical data sets also tend to be biased towards the "best reservoir" as they were done to analyze hydrocarbon potential within a reservoir, and as such will often yield the highest results for permeability measurements. It was decided that based on the large range of permeabilities within the core plugs, the best representation of reservoir permeability exclusive of the fracture permeability (because core plugs typically represent unfractured rock samples) is the core K90 measurement of permeability. The K90 permeability is measured at 90 degrees to the maximum permeability direction within the core plug. This was interpreted to represent reservoir permeability that is dominated by the rock matrix driven by intercrystalline porosity associated with replacement sucrosic dolomite texture (euhedral dolomite crystal shapes). The distribution for permeability from the declustered core data can se seen in Figure 45.

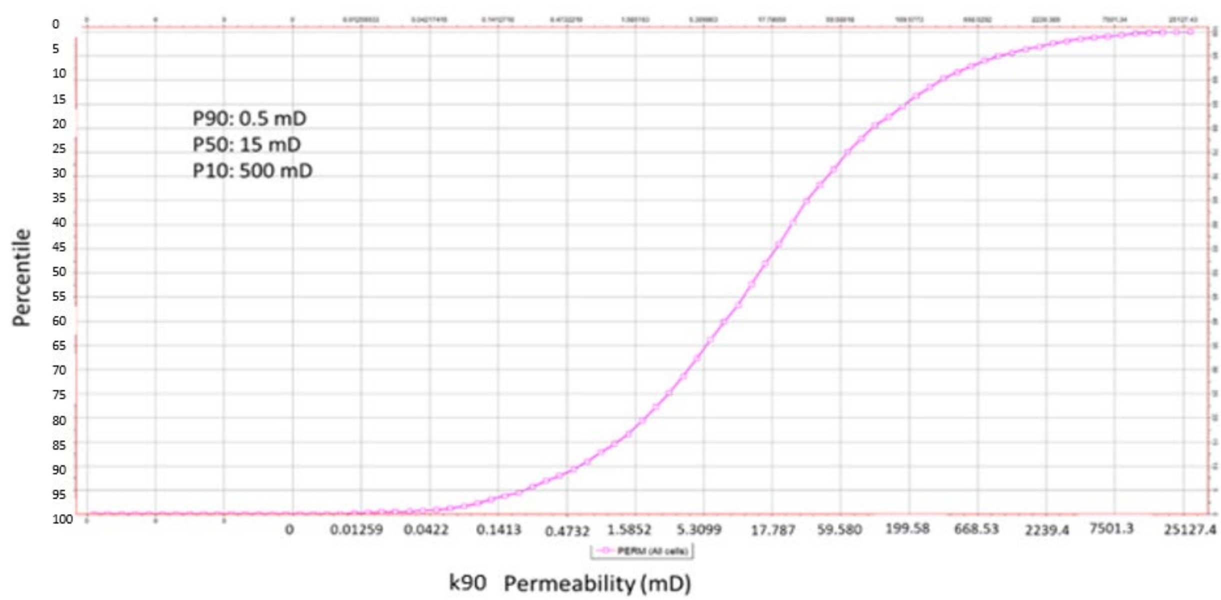

Figure 46: Cumulative Distribution Curve for permeability from declustered K90 core data

Long term production tests or actual production data provide data to estimate an average formation permeability that covers 100's of meters or kilometers of scale in the reservoir. To provide this information, E3 completed a 10-day flow and build-up test in the reservoir at E3's 102/01-16-033-27W4 well (Section 16). This location was also strategically selected to provide permeability and porosity data for the lower energy lagoon facies. Data recorders measured the reservoir pressure response from the production and injection, which was analyzed by an independent 3rd party expert (IHS Markit, part of

S&P Global) to determine the reservoir permeability within the interior lagoon facies. Reservoir pressure response was modeled using an analytical solution to match the flow test results and the permeability input to the model was determined to be a minimum of 20mD near the wellbore, increasing to 100mD as the pressure response extended further from the wellbore.

Physical measurements that represent a reservoir's ability to produce fluid are the best representation of bulk permeability of a system compared to individual measured data points that do not have associated production with them. Confidence in flow test minimum bulk permeability of 20mD is supported as it aligns with the P50 K90 permeability derived from the core analysis. These results provide increase confidence in this reservoir parameter from previous assessments.

Permeability will be incorporated into the 3D Petrel model in the future and will be used in simulation work to determine reservoir flow characteristics. Permeability was not used directly in the resource volume estimate but was utilized to estimate potential reservoir producibility which supports the evaluation of whether the resource has a reasonable prospect of economic extraction.

14.2.5. Lithium Grade

Previous precedent to evaluate continuity of resource grade for lithium brines has relied on kriging and kriging variance. This is appropriate for reservoirs where lithium grade has spatial variability. This does not align with E3's conceptual model for the Leduc Reservoir, where there is a regionally continuous, hydraulically connected aquifer where the emplaced lithium has been regionally distributed through advective and dispersive groundwater flow over a long period of geologic time.

The measured lithium concentrations in the BD have a P90-P10 range of 70.4 to 79.9mg/L with a P50 of 74.5 mg/L. E3's vertical sampling is included in this data set, which addressed a key uncertainty in the previous dataset. The lack of variation in measured vertical lithium grade supports the overall continuity of lithium across the BD as was previously indicated by the lateral sample distribution. This is consistent with the emplacement model discussed in Section 8 and validates the assumption that the grade is homogeneous in the vertical and lateral directions.

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

1. Variography
2. Descriptive statistics

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

While geostatistical approaches like kriging and variography evaluate spatial continuity in a dataset, for descriptive statistics it must be assumed that the samples are representative of the population. E3 moved to utilizing descriptive methods to evaluate the grade distribution once it was demonstrated that the samples varied by less than 1.32 mg/L and were normally distributed. E3 evaluated two descriptive statistical measurements to further evaluate the confidence in the assumption that the lithium grade distribution is homogeneous:

1. The coefficient of variation for the sample set was calculated for both the raw samples dataset (n=85) and the sample set with temporally averaged samples (n=51) and found to be very low (0.07 and 0.06) in both cases. The fact that temporal averaging reduced the coefficient of variation supports the finding from the variography work that lab analysis error may be resulting in much of the current variance observed in the samples, as these samples were collected from the same well completion interval.
2. A confidence interval following Student's t-distribution was constructed, based on the assumption that samples were drawn from the same population. For the temporally averaged dataset, the mean Lithium grade was estimated at 74.8 +/- 1.32 mg/L throughout the BD.

Based on the statistical evaluation and the completion of the vertical grade profiling, E3 and the QP's agree that the sample dataset represents a large regional area across the BD and within this dataset, lithium grade variance is small and there are no mappable spatial trends in the grade. This analysis demonstrates that it is reasonable to apply the P50 Lithium concentration of 74.5mg/L as the Lithium grade across the BD to determine the measured and indicated resource volumes.

14.2.6. Fluid Saturation

The additional fluid analyses conducted on the pressurized downhole samples validated the previous assumption that the brine saturation in the BD (outside of the hydrocarbon window) is >99%, and the entrained gas saturation is <1%. The samples were collected at reservoir conditions (90°C and ~20,000kPa) via a controlled displacement tool. The samples were maintained at reservoir conditions and transported to Core Laboratories *Advanced Technology Centre* in Calgary for analyses. Direct measurement of the fluid saturation below the hydrocarbon window increases confidence in the resource volume estimates.

14.3. Resource Estimate

E3's previous resource estimates have relied on single net reservoir thickness, porosity, and lithium grade values to represent given variables used in the resource calculation. The current methodology leverages the three-dimensional geological model across the BD and enabled a novel approach to distinguishing between resource categories based on uncertainty analyses.

As demonstrated in preceding sections the BD resource area can be treated as a single continuous reservoir based on continuity in porosity (>2% effective porosity), lithium grade, and pressure dynamics. The collection of additional data and integration within the framework of the 3D geological model represents a significant improvement in volumetric estimation methodology.

As discussed in Section 14.2.3, porosity is more spatially variable than grade and was modeled using sequential gaussian simulation (14.1.3). In this analysis, 50 equiprobable realizations of effective porosity across the BD were created. Connected geobodies at 2% and 6% porosity cut-offs were evaluated for all realizations. These connected geobodies are interpreted to represent continuous reservoir facies that are capable to support economic extraction. Further justification of the 2% and 6% porosity cut-offs to support the Indicated vs. Measured resource volumes is described below.

The geostatistical simulation of 50 equally plausible 3D effective porosity distributions for the resource quantified the uncertainty in the estimated brine pore volume (and by extension resource volume) accounting for the uncertainty in the measured data. Specifically, based on the current data locations, density and range in the effective porosity values, the difference in overall P10 and P90 brine pore volume between all 50 realizations is 12% (Table 12). On this basis E3 has selected P50 volume calculated from the 50 realizations that evaluated the connected effective porosity as the basis for the estimate.

Consistent with E3's Inferred resource estimate, and effective porosity cut off was used and E3 has accounted for the presence of hydrocarbons in the reservoir. The hydrocarbon pore volumes from Leduc oil & gas fields were pulled from public data (Appendix G) and sum of the original oil in place (OOIP) and original gas in place (OGIP) from Leduc pools in the BD were removed from the total pore volume. As OOIP and OGIP volumes are reported at surface conditions and both fluids are significantly more compressible than water, the appropriate formation volume factors were applied to calculate the pore volume impact at reservoir conditions. E3's 2022 sampling program demonstrated that <1% of the total fluid volume was entrained gas, and therefore a brine saturation percentage with a value of 99% was used.

The following methodology used in the brine resource volume estimate is provided:

- Step 1: Export the total connected pore volume from 50 realizations of the geological, and calculate the P50 value from 50 realizations for areas greater than 2% effective porosity cut-off
- Step 2: Subtract the OOIP and OGIP from the P50 total connected pore volume
- Step 3: Multiply the total pore volume by the brine saturation of 99% to determine brine volume

The total pore volume in the BD is calculated to be ~40 km^3 of resource brine in high permeability zones (Table 12).

Table 12: Bashaw District Brine Volume above 2% effective porosity cut-off

<table>
<tr><th>Pore Volume [m^3]</th><th>Bashaw OOIP [m^3]</th><th>Brine Volume [m^3]</th></tr>
<tr><td>P50: 55,853,000,000
P90: 53,600,000,000
P10: 60,770,000,000</td><td>54,299,410</td><td>P50: 40,355,000,000
P90: 38,124,000,000
P10: 45,222,000,000</td></tr>
<tr><td>Li-Rich Brine Saturation</td><td>Bashaw OGIP [m^3]</td><td>Brine Volume [km^3]</td></tr>
<tr><td>99%</td><td rowspan="3">15,036,100,000</td><td rowspan="3">P50: 40
P90: 38
P10: 45</td></tr>
<tr><td>Li Concentration [mg/L]</td></tr>
<tr><td>74.5</td></tr>
</table>

Note: significant digits were used for table formatting purposes, but no rounding occurred until the final step of the resource estimate (mass calculation of OLIP in LI tonnes)

14.3.1. Indicated and Measured Resource Criteria

As discussed in Section 14.2.5, E3 has a high confidence that the variability in lithium grade across the BD is low within the sampled reservoir and that the more significant factor that will influence the Resource volume is effective porosity distribution which is related to the lateral continuity and permeability (and hence producibility) of the resource. As previously discussed, the connectivity of porosity in the 3D geomodel can be quantitatively analyzed in the geomodel as geobodies.

Indicated Resource Criteria

Based on the revised porosity permeability relationship presented in Figure 39, it is observed that permeability values at reservoir core porosities (which represent effective porosity) of 2% or greater range from 0.04 to 1000 mD with a regression fit of approximately 1 mD. For reservoir permeability >1 mD the QP's have 1) moderate confidence that this rock volume has permeability that directly supports economic extraction and 2) moderate confidence that this rock volume has been adequately sampled and assessed via the information compiled to date by E3. We note that there are measurements less than 1 mD at this porosity but a large number exceed this threshold and therefore the QP's have moderate confidence that the rock volume represented in the 3D geomodel with effective porosity of at least 2% has permeability of at least 1 mD.

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

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

Measured Resource Criteria

Based on the revised porosity permeability relationship presented in Figure 39, it is observed that permeability values at reservoir core porosities (which represent effective porosity) of 6% or greater range from 0.1 to 30000 mD with a regression fit of approximately 10 mD. For reservoir permeability >10 mD the QP's have 1) high confidence that this rock volume has permeability that directly supports economic extraction and 2) high confidence that this rock volume has been adequately sampled and assessed via the information compiled to date by E3 to provide sufficient confidence in the continuity of these zones to support a reserve estimate. We note that there are measurements less than 10 mD at this porosity but a significant number of measurements exceed this threshold and therefore the QP's have moderate confidence that the rock volume represented in the 3D geomodel with effective porosity of at least 6% has permeability of at least 10 mD.

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

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

14.3.2. Indicated & Measured Volumes

The steps to estimate measured resource volume is provided:

- Step 1: For each of 50 realizations, generate a geobody showing all connected porosity above 6% porosity that intersects a measured Lithium data sampling point, and export the P50 pore volume
- Step 2: Calculate the P50 pore volume from the 50 realizations exported in Step 1
- Step 3: Calculate the net brine volume (Net pore volume from step 2 minus the hydrocarbon pore volume) x brine saturation
- Step 4: Calculate the OLIP [tonnes] (Net Lithium Volume = Net Brine Volume [m3] x 1000 [L/m3]) x P50 Li concentration [mg/L]) / one billion [mg/tonne])
- Step 5: Calculate the OLIP [LCE] (Li tonnes from Step 4 x 5.323)

The steps to estimate indicated resource volume is provided:

- Step 1: For each of 50 realizations, generate a geobody showing all connected porosity above 2% porosity that intersects a measured Lithium data sampling point, and export the P50 pore volume
- Step 2: Calculate the P50 pore volume from the 50 realizations exported in Step 1 minus Measured P50 pore volume)
- Step 3: Calculate the net brine volume (Net pore volume from step 2 minus the hydrocarbon pore volume) x brine saturation
- Step 4: Calculate the OLIP [tonnes] (Net Lithium Volume = Net Brine Volume [m3] x 1000 [L/m3]) x P50 Li concentration [mg/L]) / one billion [mg/tonne])
- Step 5: Calculate the OLIP [LCE] (Li tonnes from Step 4 x 5.323)

A summary of the BD total, measured, and indicated resource volumes is provided in Table 13:

Table 13: Bashaw District Total, Measured, and Indicated Resource Estimates

	OLIP (Li tonnes)	OLIP (LCE tonnes)
Bashaw District Net OLIP (excluding hydrocarbon pore volumes)	3,006,000	16,003,000
Bashaw District Indicated Resource (excluding hydrocarbon pore volumes)	1,766,000	9,404,000
Bashaw District Measured Resource (Excluding hydrocarbon pore volumes)	1,239,000	6,598,000

A visual representation of the measured and indicated volumes are shown in Figure 46, based on a single realization where the volumes are closest to the P50 volumes. As the P50 volumes were calculated from the exports across all 50 realizations, no single realization is an exact match to the reported resource volume estimate. The visual representation projects the vertical variation to a plan view, based on the ratio of measured and indicated volumes occurring in a given column of model grid cells. Where the ratio is above 0.5, the representation shows green for measured; below 0.5, the representation shows yellow for indicated.

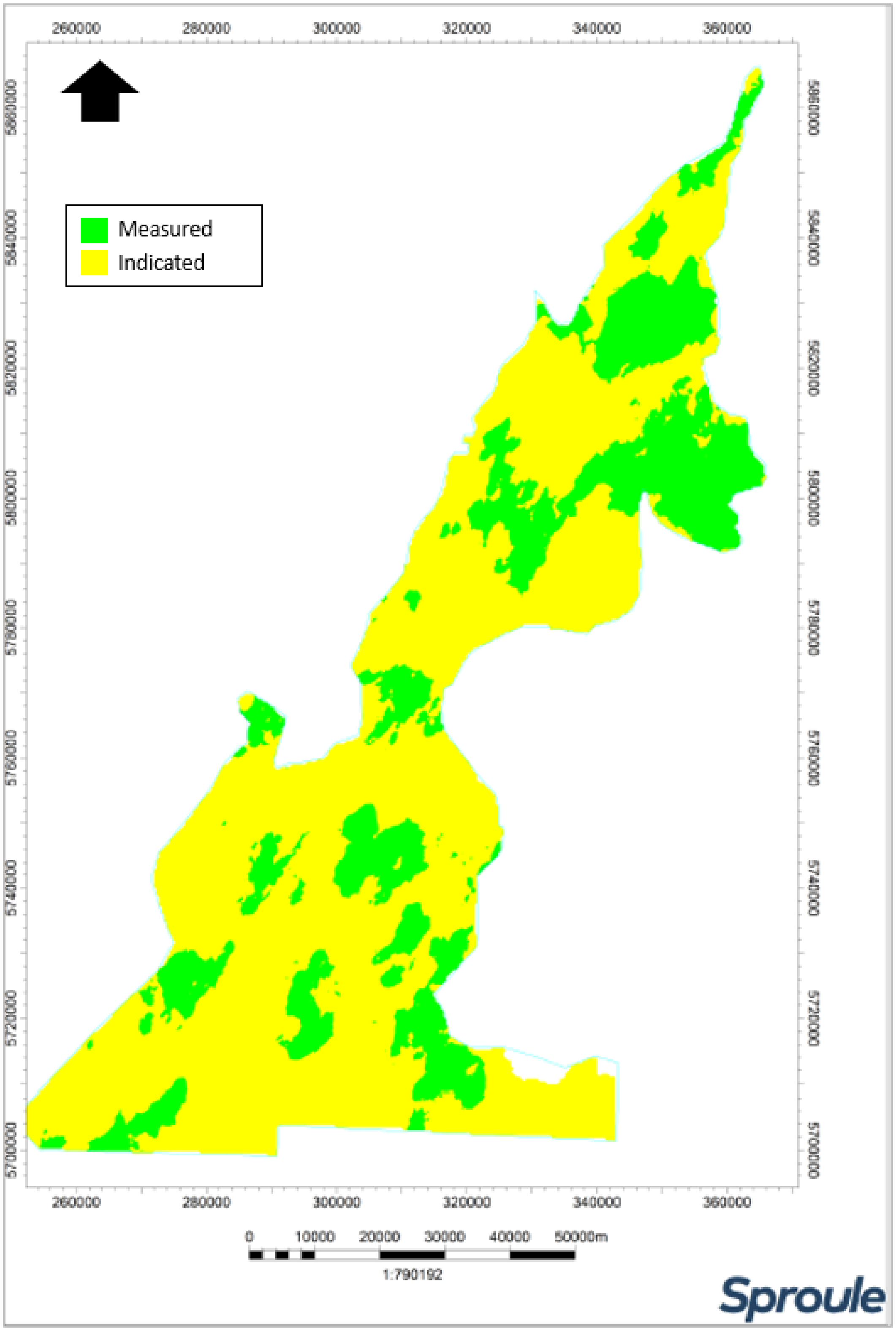

Figure 47: Visual Representation of Indicated and Measured resource volumes across the Bashaw District

The indicated and measured mineral resource estimates have been prepared to be consistent with the NI 43-101 Standards of Disclosure for Mineral Projects (National Instrument, 2016[lxxix]); Form 43-101F1 (National Instrument, 2011[lxxx]); CIM Definition Standards (CIM 2014[lxxxi]); and the CIM Best Practice Guidelines for Reporting of Lithium Brine Resource and Reserves (CIM 2012[lxii]).

14.4. Resource Statement

The data sources used for the mineral resource include historical well data logs, core logs developed by E3, and brine samples collected by E3 from currently operating Leduc wells, and a 3D Petrel geological model.

The two key findings of this assessment include:

1. The assessment that lithium concentrations are statistically consistent vertically and laterally throughout the Bashaw District
2. E3 and QP's have a high confidence that the 6% or greater connected porosity volume represents a laterally continuous and connected resource that can be economically extracted. This confidence is sufficient to allow the application of modifying factors in sufficient detail to support mine planning and final evaluation of economic viability of a resource. The confidence level This was classified as a Measured Resource.
3. E3 and QP's have a moderate confidence that the 2% or greater connected porosity volume represents a laterally continuous and connected resource that can be economically extracted. This confidence is sufficient to allow the application of modifying factors in sufficient detail to support mine planning and final evaluation of economic viability of a resource. This was classified as an Indicated Resource.

Using the methodology described above, the total Indicated and Measured resource estimate for the Bashaw District is 3,006,000 tonnes of lithium, which equates to 16,003,000 tonnes of lithium carbonate equivalent (LCE)[3].

The Indicated portion of the resource is 9,404,000 tonnes LCE and is classified as indicated due to the evidence being sufficient to assume geological, grade, and quality continuity between points of observation. This confidence is sufficient to allow the application of modifying factors in sufficient detail to support mine planning and final evaluation of the economic viability of the resource.

The Measured portion of the resource is 6,598,000 tonnes LCE and is classified as measured due to the geological evidence being sufficient to confirm geological, grade and quality continuity between points of observation. This confidence is sufficient to allow the application of modifying factors in sufficient detail to support mine planning and final evaluation of economic viability of a resource.

The Mineral Resource figures have been rounded to reflect that they are estimates.

15. Mineral Reserve Estimates

The Project is in an early stage and a mineral reserve estimate is not applicable.

16. Mining Methods

To produce lithium, the reservoir water will be pumped to the surface from a production well as produced brine. The produced brine will be processed at the surface to remove the lithium, leveraging E3's proprietary DLE technology. The lithium-depleted brine will be injected into the reservoir using injection wells for pressure support and to maintain the reservoir voidage replacement ratio (VRR).

E3's 2022 flow test was designed and analyzed by an independent 3rd party expert (IHS Markit, part of S&P Global) to support brine producibility and injectivity.

The test involved:

- Flowing 400m^3/d of brine to surface for four days, using an electronic submersible pump (ESP)
- Shutting in the well for seven days and monitoring well buildup
- Re-injecting the produced brine in <2 days at a rate of 1,200m^3/d
- Shutting in the well for one day and monitoring well falloff

The flow test results observed:

- Bulk permeability of ~20mD
- Radial flow patterns
- Consistent results from both the buildup and falloff tests
- Reservoir boundaries were not defined by the test
- The minimum area evaluated by the test is 4.4km in diameter

This data is critical in advancing the understanding of the resource. The test experienced high near-wellbore damage ("skin", of ~65 [unitless]) which restricts the calculated maximum stable rate to ~500m3/d. If the skin damage is reduced to a reasonable and achievable value of 5 through an acid cleanout workover, the calculated maximum stable rate is ~1,750m3/d. The implication is that the overall well count will increase if the skin effect cannot be reduced. The injectivity test demonstrated that an injection rate of 1,200 m^3/d was readily accepted by the reservoir. Taken in conjunction with the 60+ years of brine co-production from the Leduc reservoir from oil and gas wells, this data supports that the BD is a reasonable prospect for eventual economic extraction.

17. Recovery Methods

No work has been completed for this section for the BD resource area. A PEA was previously completed for the Clearwater Lithium Project, which is a sub area of the BD[xv].

18. Project Infrastructure

No work has been completed for this section for the BD resource area. A PEA was previously completed for the Clearwater Lithium Project, which is a sub area of the BD[xv].

19. Market Studies and Contracts

No work has been completed for this section for the BD resource area. A PEA was previously completed for the Clearwater Lithium Project, which is a sub area of the BD[xv].

20. Environmental Studies, Permitting, and Social or Community Impact

No work has been completed for this section for the BD resource area. A PEA was previously completed for the Clearwater Lithium Project, which is a sub area of the BD[xv].

21. Capital and Operating Costs

No work has been completed for this section for the BD resource area. A PEA was previously completed for the Clearwater Lithium Project, which is a sub area of the BD[xv].

22. Economic Analysis

No work has been completed for this section for the BD resource area. A PEA was previously completed for the Clearwater Lithium Project, which is a sub area of the BD[xv].

23. Adjacent Properties

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

The BD claims are interspersed in a checkerboard configuration between permits held from the provincial government and those on privately-owned, freehold land. On freehold lands, metallic and industrial minerals are owned by private individuals or corporations. Production from within the permit area is to be governed by the AER with similar regulations that govern oil and gas production in the province. Outside of the permit areas (large white areas on Figure 46), the lands are held by a combination of Freehold and Crown ownership.

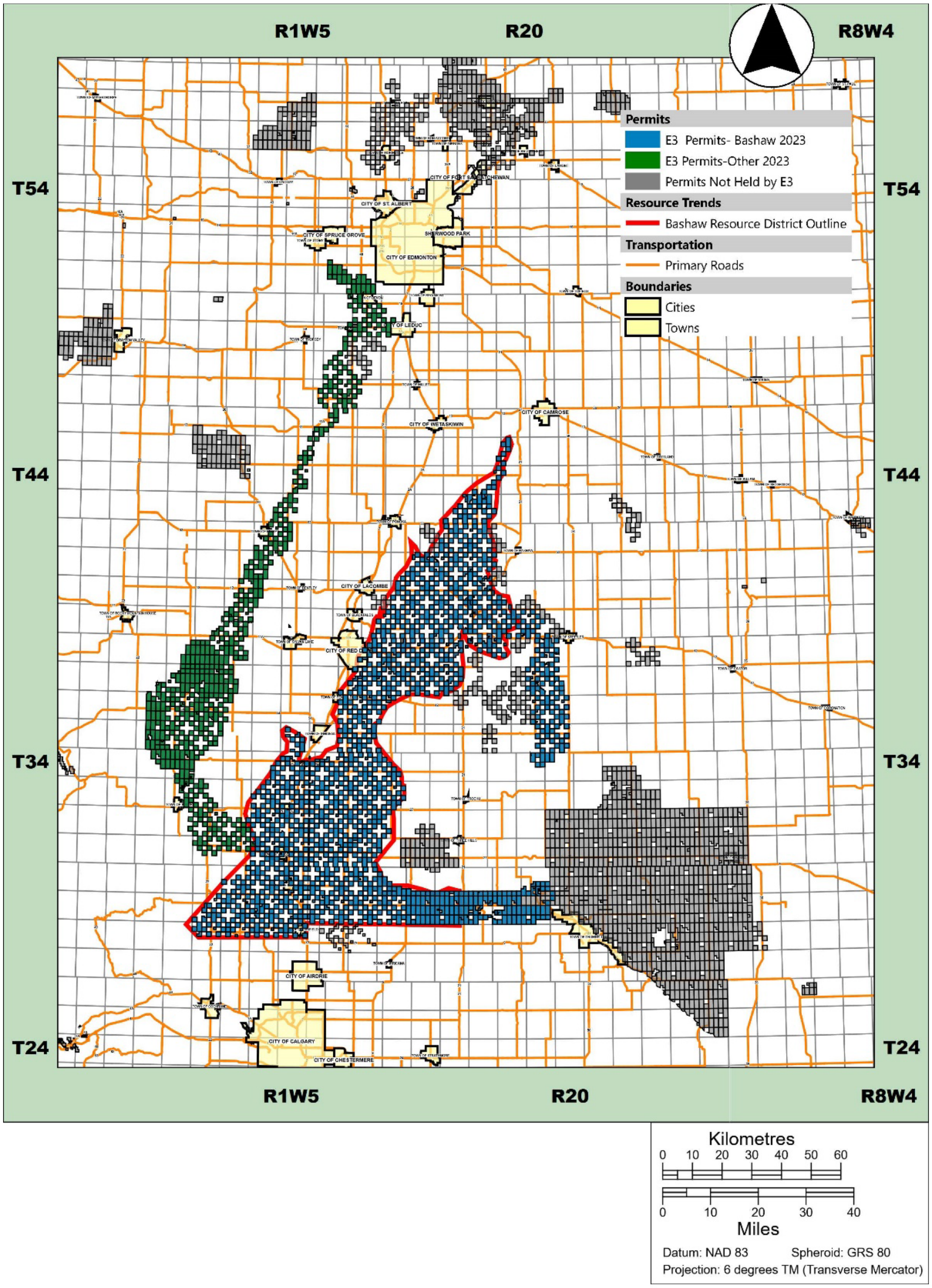

Figure 48: Adjacent Properties Map

24. Other Relevant Data and Information

24.1. Lithium Regulation in Alberta

The Alberta government 'Mineral Resource Development Act[lxxxii] for Brine-Hosted Mineral Resource Development Rules' came into force on March 1, 2023. Under this act, many of the directives for Lithium (and other brine hosted minerals) mirror current oil and gas regulatory frameworks that are well established and have been in place for several years.

Requirements for brine hosted minerals development in the province of Alberta are now included in the Alberta Energy Regulator's Directive 90[lxxxiii]. Directive 90 includes the following:

- defines the types of mineral developments, including brine-hosted mineral schemes;
- identifies the licences and authorizations for wells, facilities, pipelines, and schemes;
- extends the existing Licensee Management Program (i.e., holistic licensee assessment, estimates of liability, and security deposits) to include brine-hosted mineral developments;
- identifies the requirements for converting oil, gas, or geothermal wells to a brine-hosted minerals well;
- identifies risk assessment requirements related to hazards for brine-hosted mineral wells; and
- identifies data filing, measurement, and reporting requirements specific to brine-hosted mineral wells.

Many of the AER's requirements for oil and gas development apply to the development of brine hosted minerals. Therefore, Directive 90 references several other existing AER directives which have now been modified to include brine hosted minerals operations and development.

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

Overlapping carbon capture and sequestration (CCS) permits have been granted across portions of the BD to allow the evaluation of the Leduc to determine its suitability for CCS projects. E3 is working with the CCS evaluation permit holders to resolve subsurface conflicts and has engaged with Alberta Energy and the Alberta Energy Regulator on this topic.

24.2. Health, Safety, and Environment

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

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

25. Interpretation and Conclusions

25.1. Reasonable Prospect for Eventual Economic Extraction

The Bashaw District is a reasonable prospect for eventual economic extraction[lxxxiv] on the basis of realistically assumed and justifiable technical and economic conditions.

- The reservoir is regionally contiguous with lithium grade and reservoir properties consistent with producibility.
- Measured production and injection rates based on E3's 2022 flow test indicate sufficient transmissivity for extraction using conventional methods.
- E3 has a DLE process that is in advanced stages of development that they are confident will be able to refine lithium at reservoir concentration thresholds at or below the average concentration in this reservoir.
- Lithium has been recognized as a "critical mineral" by Natural Resources Canada[lxxxv].
- Global demand for lithium is expected to exceed supply based on electric vehicle sales and battery capacity growth[lxxxvi].

25.2. Lithium Resource Estimate

The indicated and measured mineral resource estimate for the Bashaw District is 3,006,000 tonnes of elemental lithium (16,003,000 LCE tonnes[ii]). This volume is changed from to previously published NI 43-101 reports[xv] due to the increased confidence and reduced uncertainty across the BD, quantified by the geostatistical analysis enabled by the 3D Petrel model.

Key changes driving the BD estimate include:

1. Incorporating a large data suite into a geologic model in Petrel to integrate interpretation of multiple data types (core logs and petrophyiscs) and parameterize porosity and thickness of the Leduc Formation
2. New and repeated sampling within the resource area resulted in an updated P50 lithium concentration of 74.5 mg/L, and consistent Lithium concentrations sampled vertically in the Upper, Middle and Lower Leduc formation.
3. Statistical validation that the updated combined lithium grade dataset is representative of the full resource domain and has low variance laterally and vertically.
4. Geostatistical simulation of 50 realizations of the reservoir pore volume including:

a. Updated reservoir volumetrics generated using a range of values and applied over 100,000,000+ cell blocks within the model.
b. Petrel modeling and declustering of the porosity data to better represent the ranges of porosity, and the relationship between porosity and depth within the Leduc.
c. Direct export of volumes in the Leduc reservoir, rather than calculating based on a single value for each variable
d. Using exported brine volumes generated from connected geobodies above 2% and 6% porosity that intersect measured Lithium sampling data points to determine indicated and measured brine volumes.
e. Uncertainty analysis based on 50 realizations to understand potential range of connected porosity and support use of P50 connected porosity

5. Further support of a brine saturation percentage factor of 1% to account for potential dissolved gases within the water saturated portion of the reservoir via collection of pressurized brine samples taken at reservoir temperature and pressure.

25.3. Lithium Processing / Production

E3 will apply a DLE technology that includes a proprietary ion exchange sorbent material that offers high selectivity for lithium above all other cations in the brine. E3 is continuing to develop its DLE technology.

E3 is also further identifying, developing, and evaluating flowsheets to produce lithium hydroxide from the DLE eluate. This work aims to select the optimum flowsheets (as it relates to cost, performance, environmental impact, and risks) for continued development and testing. To support this, E3 has completed a desktop study with process simulations of circuits that include the purification, concentration, and lithium hydroxide production steps and reflect the range of DLE eluate characteristics.

25.4. Significant Risks and Uncertainties

To progress from an indicated & measured resource, to reserves, the following risks and uncertainties have been identified:

1. Technical Risks: Lithium resource

   a. Existing porosity, permeability, and grade measurements are still mainly concentrated in the hydrocarbon pools within the BD
   b. Uncertainty in the resource estimate can be further reduced by additional data acquisition

2. Technical Risks: Ability to produce

   a. Potential production and injection rates for full Leduc perforations are currently calculated based off only one flow test
   b. Hydraulic continuity between interior and margin areas has been inferred from regional data, not physically validated by long term pressure transient data

c. Timing and magnitude of break-through of lithium-depleted brine that is re-injected into the reservoir reaching the production wells
d. Maintaining reservoir pressures to maintain flow
e. Relationship of porosity to permeability is variable across the BD area and the specific factors controlling variability have not been discretely represented in the model
f. Processing rates for the DLE process are currently a scaled value from lab-scale testing

   i. Final DLE flowsheet is still under development
   ii. Downstream processing of the eluate is under development

3. Regulatory Risks:

   a. Pore space competition between Brine hosted minerals resources and Carbon capture utilization and storage interests
   b. Freehold land ownership and crown ownership for mineral permits not held by E3 will require agreements to equitably produce

26. Recommendations

E3 is progressing the resource upgrade and lithium processing in parallel as work continues to support planned commercial development. As such, the work and costs recommended below are not contingent on each other.

26.1. Resource Upgrade(s)

Characterization of the Leduc resource brine geology and properties benefits from an abundance of data compiled by the oil and gas industry. To better characterize the potential brine production from this project, additional data and further characterization of existing data is required to further characterize the reservoir and upgrade the resource to a reserve. Further upgrading the resource to a reserve category requires analysis and application of Modifying Factors, such as refining well networks and evaluation of commercial DLE facility options.

Recommended activities to continue to refine the resource estimate include:

- Additional drilling / testing of existing wells
  a. Additional porosity and permeability data
  b. Additional analysis to compare new data to previous parameter distributions and petrophysical models
  c. Complete additional flow tests over the entire reservoir thickness
- Additional grade sampling
  a. Of produced water from oil and gas wells
  b. Of brine samples from lithium wells
  c. Of vertically segregated zones
- Complete reservoir simulations to model flow characteristics for planning of a well network production and injection scheme

a. Address variability in the porosity-permeability relationship by:
    i. Utilizing K90 as opposed to KMax to inform the relationship
    ii. Utilize a statistical transformation as opposed to regression to parameterize permeability from the porosity values, to represent the full range of uncertainty in the porosity-permeability relationship
b. Calibrate geological model to flow test to validate reservoir simulations
c. Determine brine production type curve(s)
d. Determine brine injection type curve(s)
e. Conduct economic analyses

- Perform special core analysis to help simulate single phase flow characteristics for injection, and to evaluate potential for breakthrough of re-injected depleted brine; this information will be used to evaluate a lithium recovery factor assuming this production scheme

E3 has communicated their intent to complete aspects of the above work to the QPs. The QPs have not independently verified the costs associated with these activities. Additional costs are estimated on an annual basis for ~3 years, until commercial development commences: drilling at $2-$6 million/year; grade sampling at $100,000/year; reservoir simulations at $50,000/year; and special core analysis at $50,000/year.

26.2. Lithium Processing

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

- Confirm the sorbent performance, kinetic and equilibrium data
- Optimization of the current IX system envisaged; compare the current “sorbent-in-brine” IX circuit with a fixed bed system
- Quantify the removal efficiencies and species formed for secondary contaminants such as boron, strontium, and manganese removed in the secondary purification stage where impurities (largely calcium and magnesium) are removed via precipitation; simulate the system at lab scale
- Demonstrate the feasibility of the IX process at pilot scale using Leduc brine
- Demonstrate feasibility of downstream processing using Leduc brine

The estimated cost associated with this work ~CAD$8,500,000.

26.3. Pre-Feasibility Study

Completion of a Pre-Feasibility Study is the minimum prerequisite for the conversion of mineral resources to mineral reserves. CIM defines a PFS as:

> *A Pre-Feasibility Study is a comprehensive study of a range of options for the technical and economic viability of a mineral project that has advanced to a stage where a preferred mining method, in the case of underground mining, or the pit configuration, in the case of an open pit, is established and an effective method of mineral processing is determined. It includes a financial analysis based on reasonable assumptions on the Modifying Factors and the evaluation of any other relevant factors which are sufficient for a Qualified Person, acting reasonably, to*

determine if all or part of the Mineral Resource may be converted to a Mineral Reserve at the time of reporting.

E3 has communicated their intent to complete a PFS to the QPs. The QPs have not independently verified the costs associated with these activities. The cost to develop a PFS, including pre-FEED engineering design, is estimated at $8 million, leading up to commercial development.

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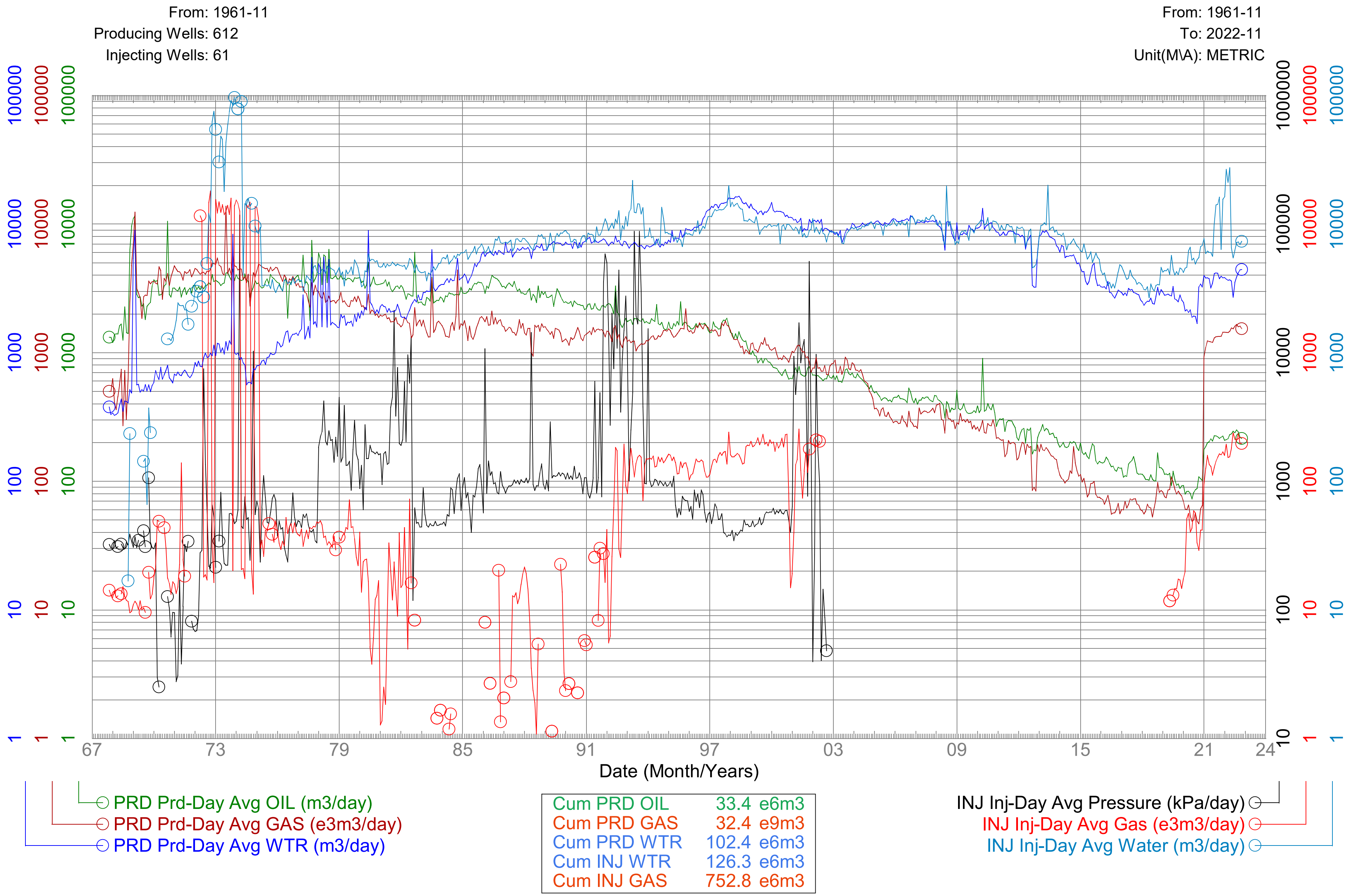
[lxxxv] https://www.nrcan.gc.ca/our-natural-resources/minerals-mining/minerals-metals-facts/lithium-facts/24009

[lxxxvi] https://www.rkequity.com/

Agreement No.	Property	Representative	Original Staking Date	Deadline to Apply for BH Minerals Licence
9316060174	Bashaw	1975293 Alberta Ltd.	6/20/2016	12/31/2023
9316060175	Bashaw	1975293 Alberta Ltd.	6/20/2016	12/31/2023
9316060176	Bashaw	1975293 Alberta Ltd.	6/20/2016	12/31/2023
9316060177	Bashaw	1975293 Alberta Ltd.	6/20/2016	12/31/2023
9316060178	Bashaw	1975293 Alberta Ltd.	6/20/2016	12/31/2023
9316060179	Bashaw	1975293 Alberta Ltd.	6/20/2016	12/31/2023
9316070175	Bashaw	1975293 Alberta Ltd.	7/5/2016	12/31/2023
9316070198	Bashaw	1975293 Alberta Ltd.	7/18/2016	12/31/2023
9316070199	Bashaw	1975293 Alberta Ltd.	7/18/2016	12/31/2023
9316070200	Bashaw	1975293 Alberta Ltd.	7/18/2016	12/31/2023
9317060252	Bashaw	1975293 Alberta Ltd.	6/26/2017	12/31/2023
9317060254	Bashaw	1975293 Alberta Ltd.	6/26/2017	12/31/2023
9317060255	Bashaw	1975293 Alberta Ltd.	6/26/2017	12/31/2023
9317060260	Bashaw	1975293 Alberta Ltd.	6/26/2017	12/31/2023
9318050395	Bashaw	1975293 Alberta Ltd.	5/28/2018	12/31/2023
9318050396	Bashaw	1975293 Alberta Ltd.	5/25/2018	12/31/2023
9317060214	Bashaw	1975293 Alberta Ltd.	6/20/2017	12/31/2023
9317060215	Bashaw	1975293 Alberta Ltd.	6/20/2017	12/31/2023
9317060216	Bashaw	1975293 Alberta Ltd.	6/20/2017	12/31/2023
9317060219	Bashaw	1975293 Alberta Ltd.	6/20/2017	12/31/2023
9317060220	Bashaw	1975293 Alberta Ltd.	6/20/2017	12/31/2023
9317060238	Bashaw	1975293 Alberta Ltd.	6/20/2017	12/31/2023
9317060253	Bashaw	1975293 Alberta Ltd.	6/26/2017	12/31/2023
9317060256	Bashaw	1975293 Alberta Ltd.	6/26/2017	12/31/2023
9317060257	Bashaw	1975293 Alberta Ltd.	6/26/2017	12/31/2023
9317060258	Bashaw	1975293 Alberta Ltd.	6/26/2017	12/31/2023
9317050246	Bashaw	1975293 Alberta Ltd.	5/12/2017	12/31/2023
9319050184	Bashaw	1975293 Alberta Ltd.	5/6/2019	12/31/2023
9319100157	Bashaw	1975293 Alberta Ltd.	10/15/2019	12/31/2023
9319110154	Bashaw	1975293 Alberta Ltd.	11/7/2019	12/31/2023
9320100056	Bashaw	1975293 Alberta Ltd.	10/30/2020	12/31/2023
9321070251	Bashaw	1975293 Alberta Ltd.	7/21/2021	12/31/2023
9321070259	Bashaw	1975293 Alberta Ltd.	7/23/2021	12/31/2023
9321070260	Bashaw	1975293 Alberta Ltd.	7/23/2021	12/31/2023
9321070261	Bashaw	1975293 Alberta Ltd.	7/23/2021	12/31/2023
9321070262	Bashaw	1975293 Alberta Ltd.	7/23/2021	12/31/2023
9321070263	Bashaw	1975293 Alberta Ltd.	7/23/2021	12/31/2023
9321070264	Bashaw	1975293 Alberta Ltd.	7/23/2021	12/31/2023
9321080140	Bashaw	1975293 Alberta Ltd.	8/13/2021	12/31/2023
9321080141	Bashaw	1975293 Alberta Ltd.	8/13/2021	12/31/2023
9321080142	Bashaw	1975293 Alberta Ltd.	8/13/2021	12/31/2023
9321080143	Bashaw	1975293 Alberta Ltd.	8/13/2021	12/31/2023
9321080144	Bashaw	1975293 Alberta Ltd.	8/13/2021	12/31/2023
9321080145	Bashaw	1975293 Alberta Ltd.	8/13/2021	12/31/2023
9321080146	Bashaw	1975293 Alberta Ltd.	8/13/2021	12/31/2023
9322110176	Bashaw	1975293 Alberta Ltd.	11/24/2022	12/31/2023

ALL BASHAW DISTRICT WELLS PRODUCTION/INJECTION

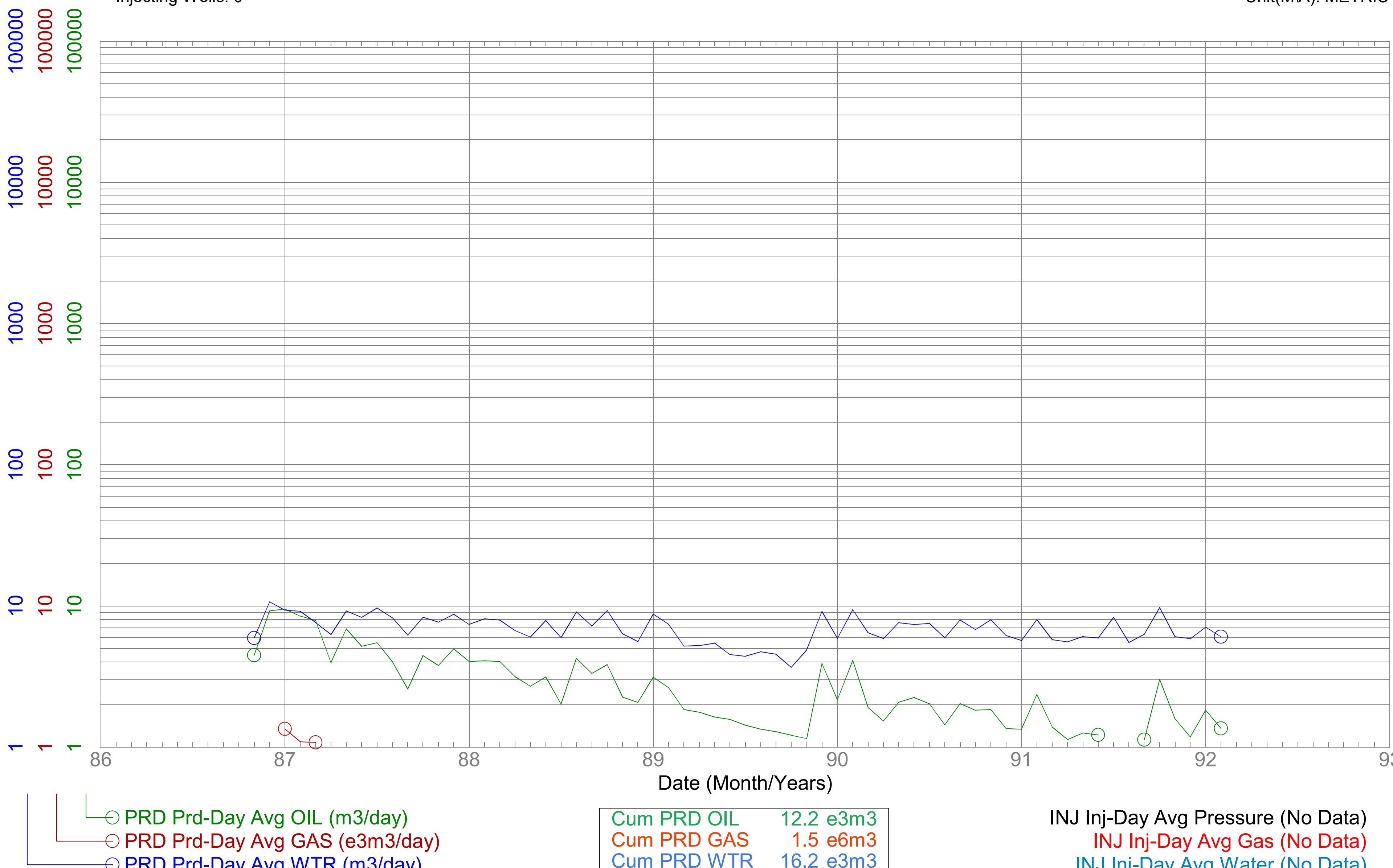


geoSCOUT www.geologic.com

ALIX FIELD WELLS PRODUCTION/INJECTION

From: 1984-10
Producing Wells: 1
Injecting Wells: 0

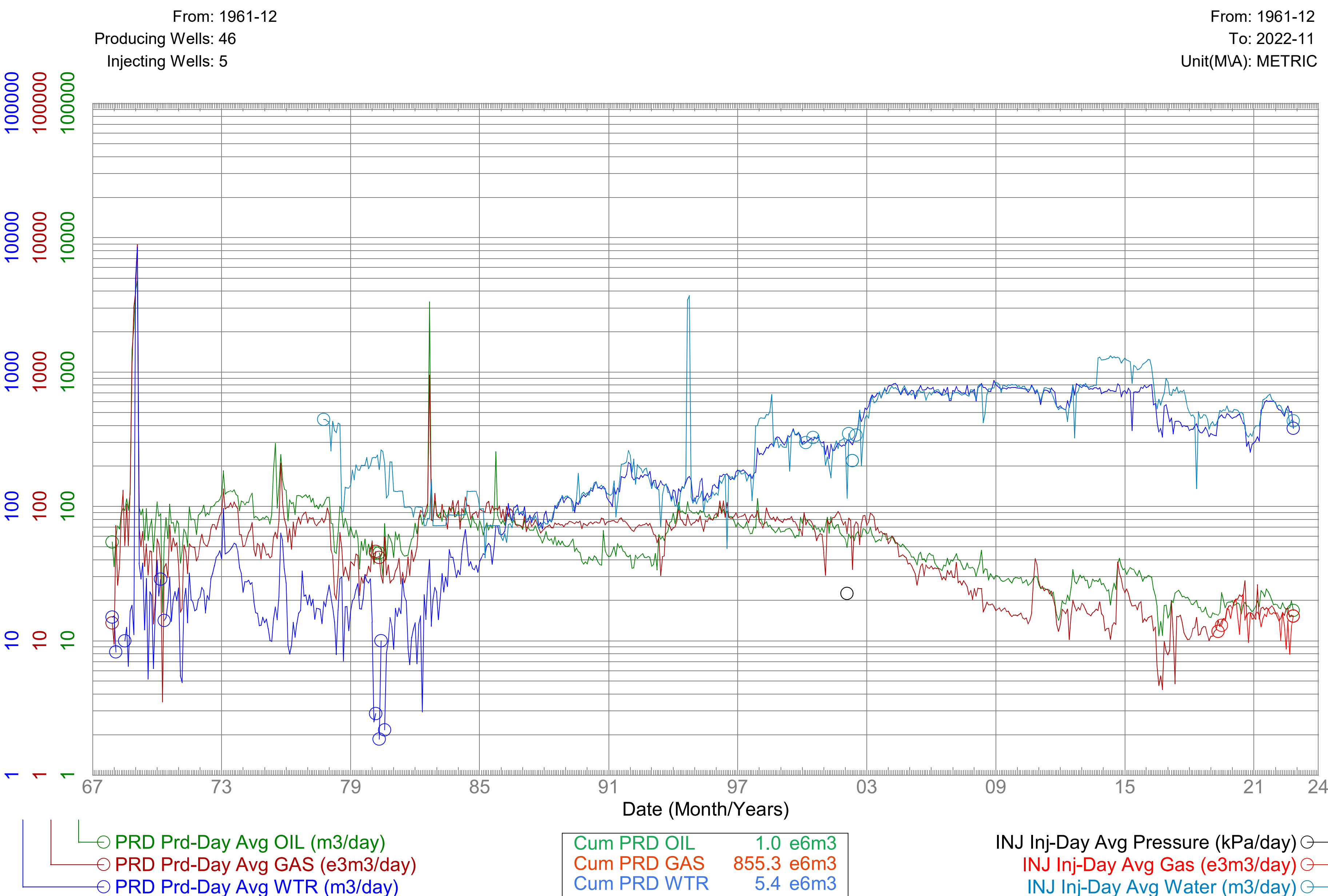
From: 1984-10
To: 1993-09
Unit(M\A): METRIC



Cum PRD OIL	12.2 e3m3
Cum PRD GAS	1.5 e6m3
Cum PRD WTR	16.2 e3m3
Cum INJ WTR	0.0 e3m3
Cum INJ GAS	0.0 e3m3

INJ Inj-Day Avg Pressure (No Data)
INJ Inj-Day Avg Gas (No Data)
INJ Inj-Day Avg Water (No Data)

BASHAW FIELD WELLS PRODUCTION/INJECTION

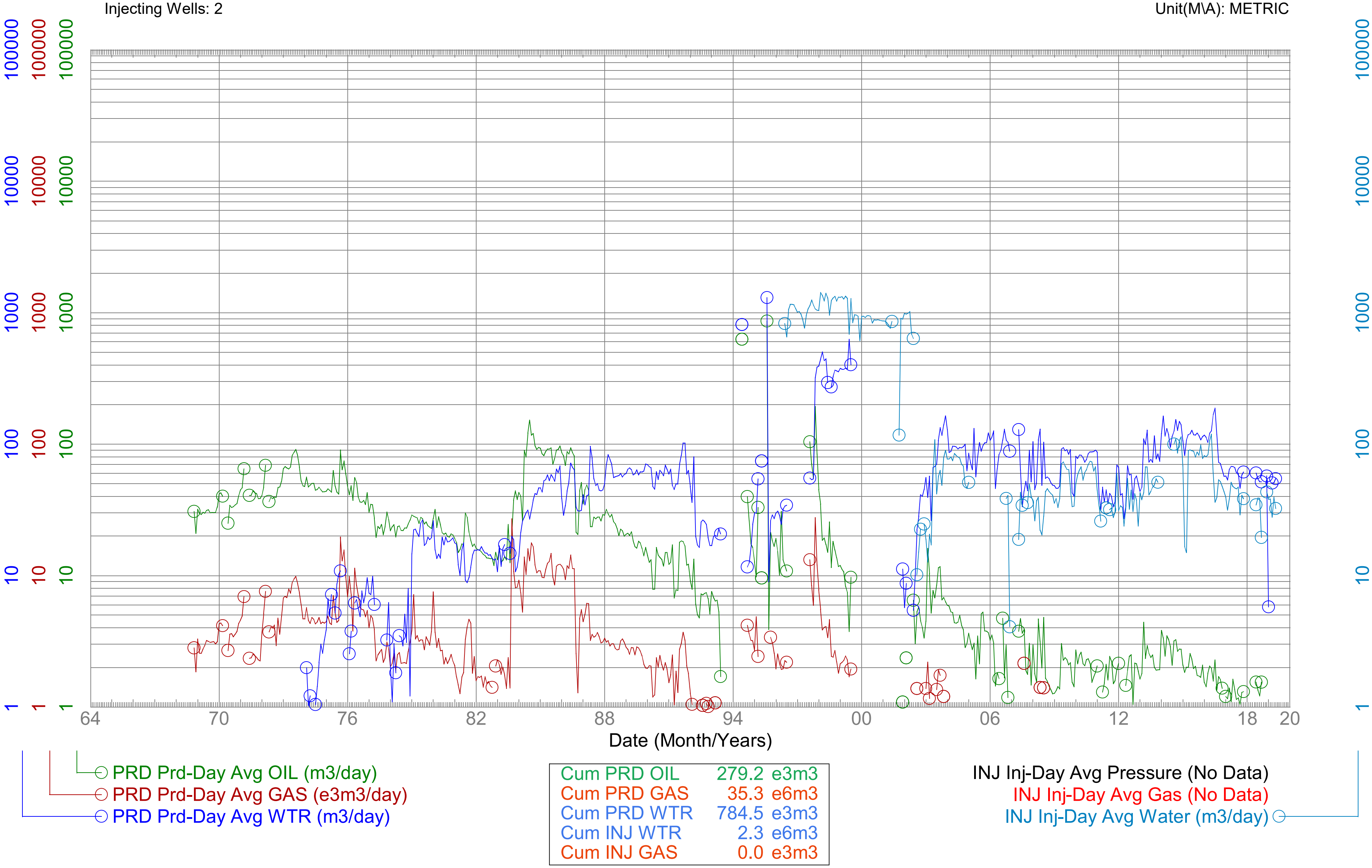


Cum PRD OIL	1.0 e6m3
Cum PRD GAS	855.3 e6m3
Cum PRD WTR	5.4 e6m3
Cum INJ WTR	6.3 e6m3
Cum INJ GAS	18.0 e6m3

CHIGWELL FIELD WELLS PRODUCTION/INJECTION

From: 1964-01
Producing Wells: 14
Injecting Wells: 2

From: 1964-01
To: 2019-05
Unit(M\A): METRIC



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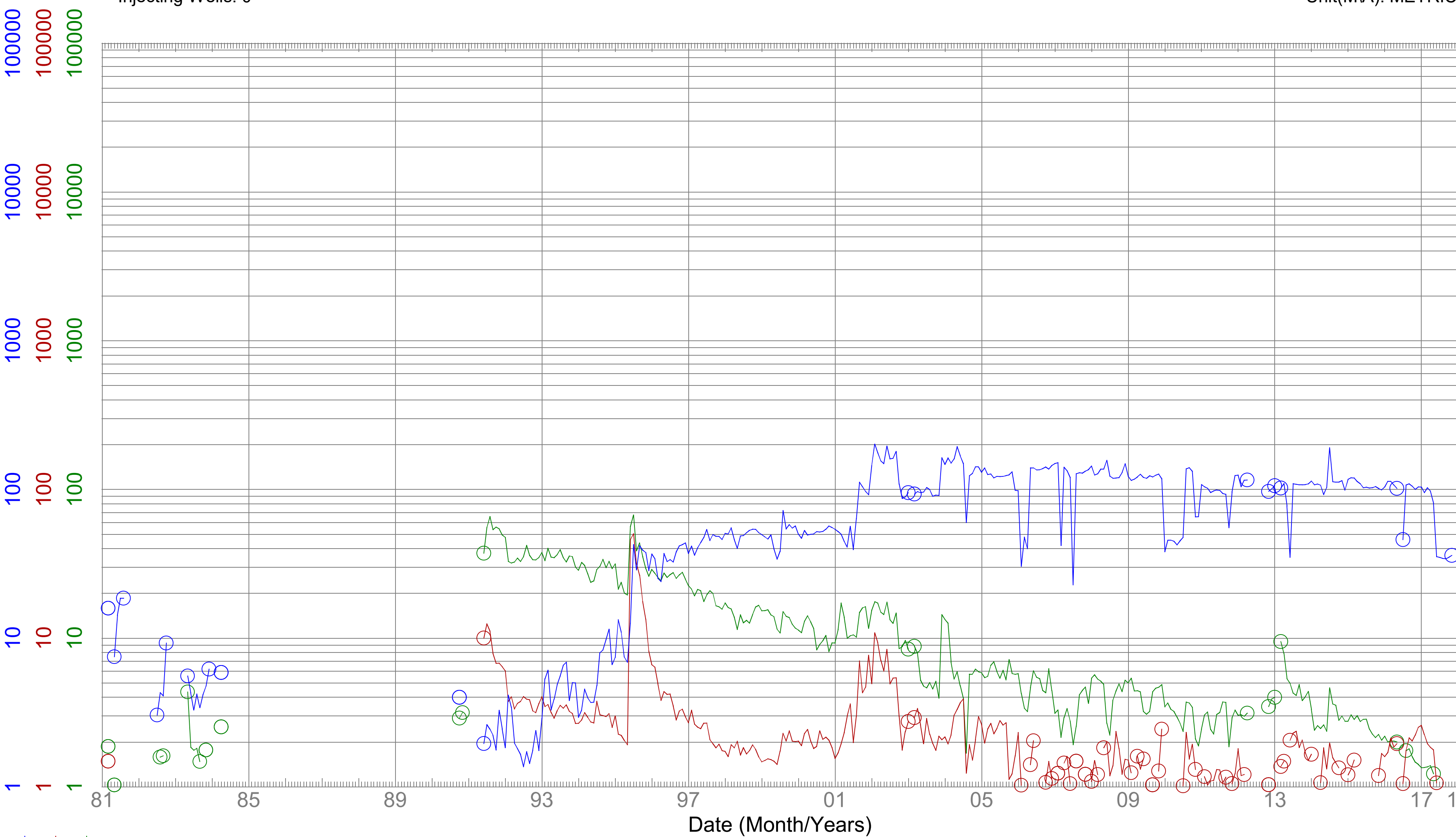
CHIGWELL NORTH FIELD WELLS PRODUCTION/INJECTION

From: 1981-03
Producing Wells: 5
Injecting Wells: 0

From: 1981-03
To: 2017-11
Unit(M\A): METRIC

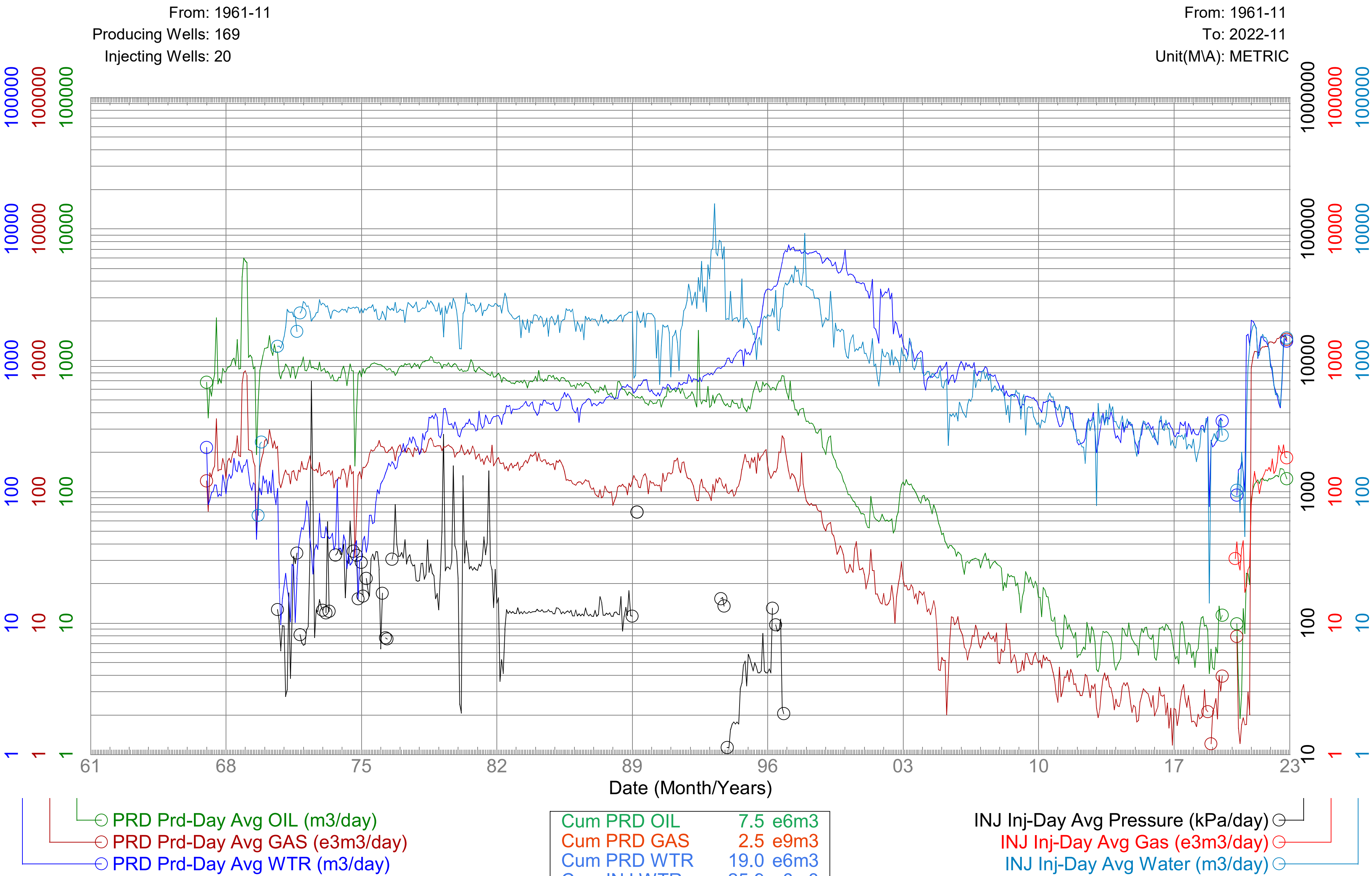


PRD Prd-Day Avg OIL (m3/day)
PRD Prd-Day Avg GAS (e3m3/day)
PRD Prd-Day Avg WTR (m3/day)

Cum PRD OIL	107.4	e3m3
Cum PRD GAS	22.7	e6m3
Cum PRD WTR	626.1	e3m3
Cum INJ WTR	0.0	e3m3
Cum INJ GAS	0.0	e3m3

INJ Inj-Day Avg Pressure (No Data)
INJ Inj-Day Avg Gas (No Data)
INJ Inj-Day Avg Water (No Data)

CLIVE FIELD WELLS PRODUCTION/INJECTION

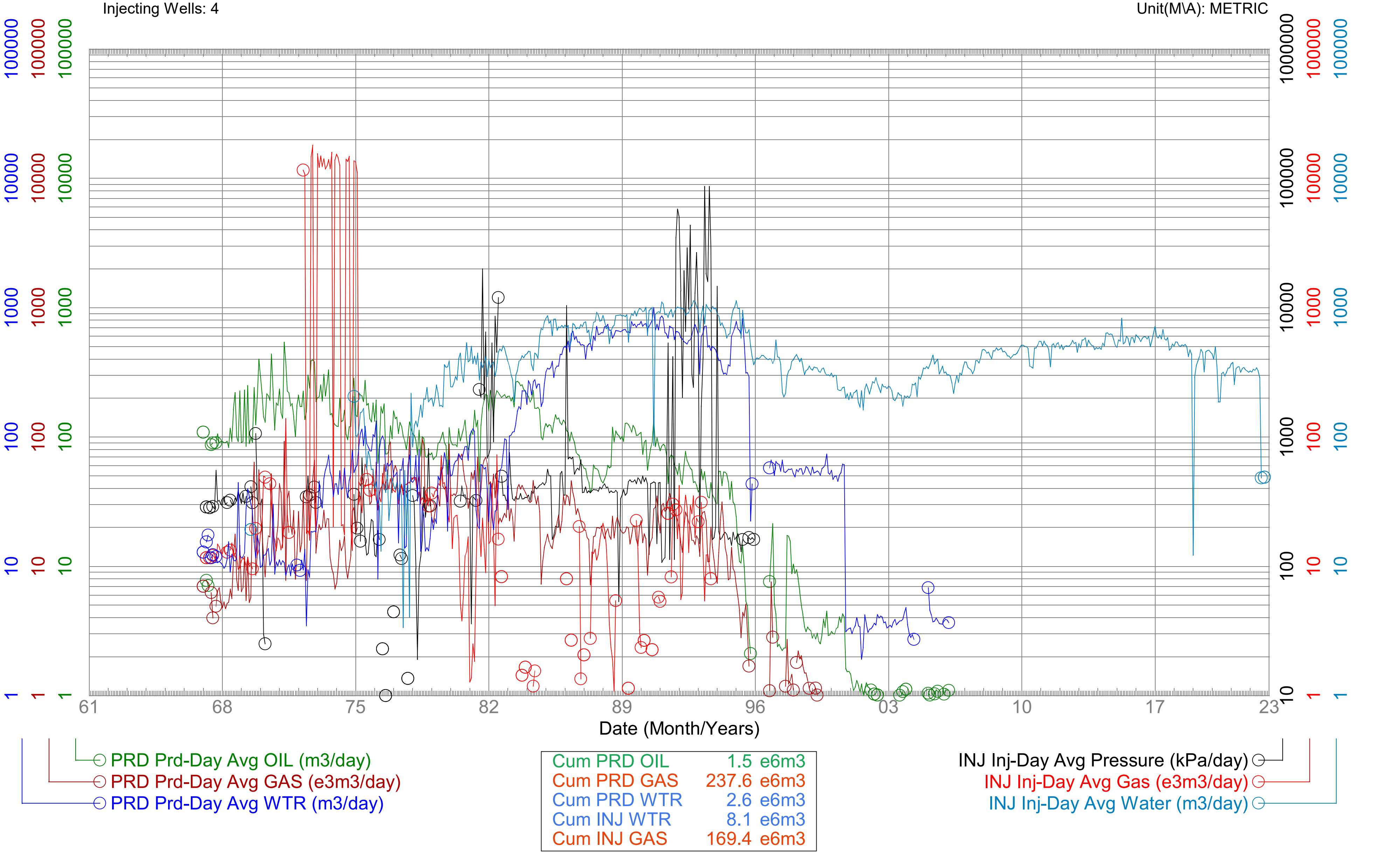


Cum PRD OIL	7.5	e6m3
Cum PRD GAS	2.5	e9m3
Cum PRD WTR	19.0	e6m3
Cum INJ WTR	25.9	e6m3
Cum INJ GAS	112.2	e6m3

DUHAMEL FIELD WELLS PRODUCTION/INJECTION

From: 1961-11
Producing Wells: 21
Injecting Wells: 4

From: 1961-11
To: 2022-10
Unit(M\A): METRIC

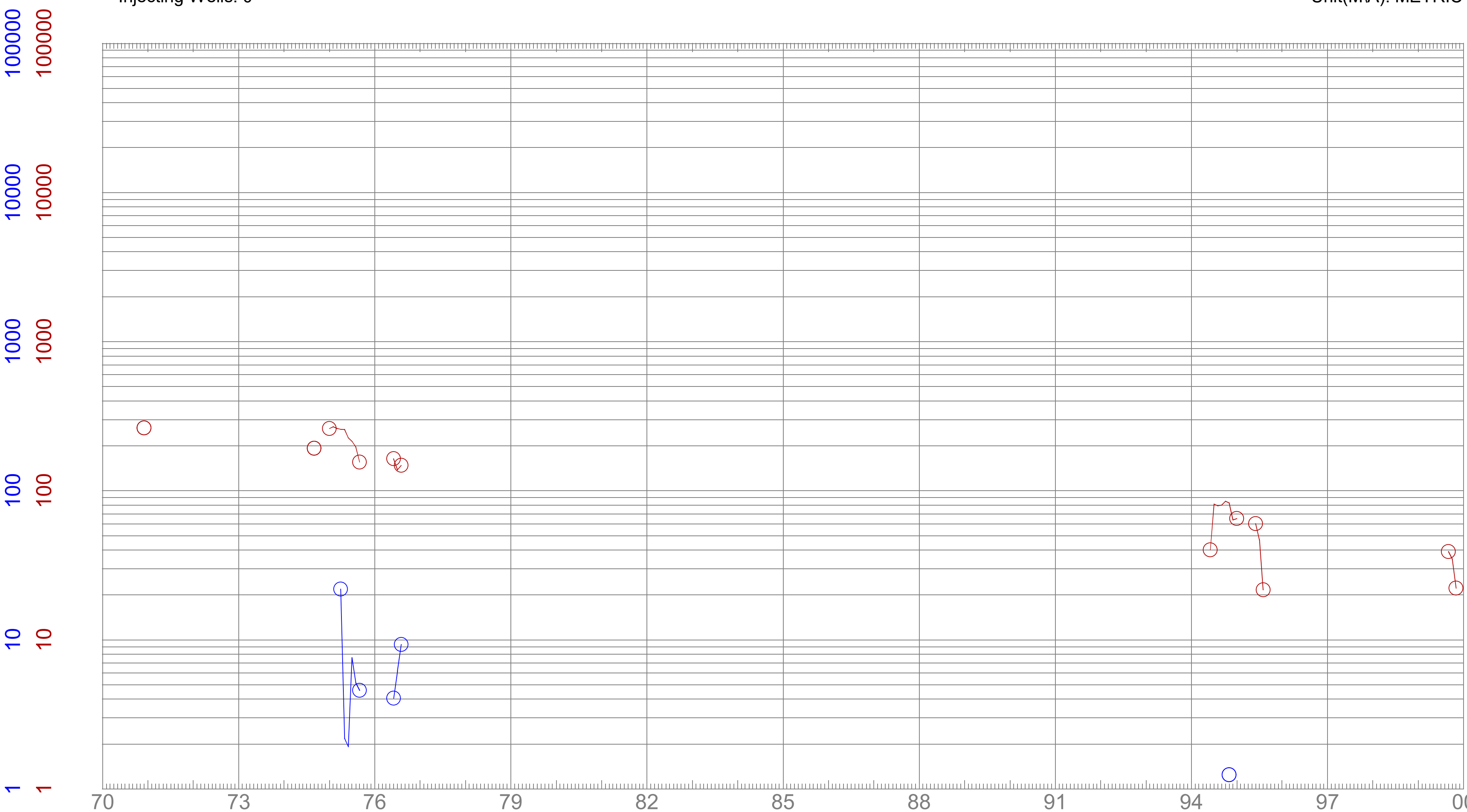


geoSCOUT www.geologic.com

ERSKINE FIELD WELLS PRODUCTION/INJECTION

From: 1970-12
Producing Wells: 2
Injecting Wells: 0

From: 1970-12
To: 1999-11
Unit(M\A): METRIC



PRD Prd-Day Avg OIL (No Data)
PRD Prd-Day Avg GAS (e3m3/day)
PRD Prd-Day Avg WTR (m3/day)

Cum PRD OIL	0.0	m3
Cum PRD GAS	83.2	e6m3
Cum PRD WTR	1.7	e3m3
Cum INJ WTR	0.0	m3
Cum INJ GAS	0.0	e3m3

INJ Inj-Day Avg Pressure (No Data)
INJ Inj-Day Avg Gas (No Data)
INJ Inj-Day Avg Water (No Data)

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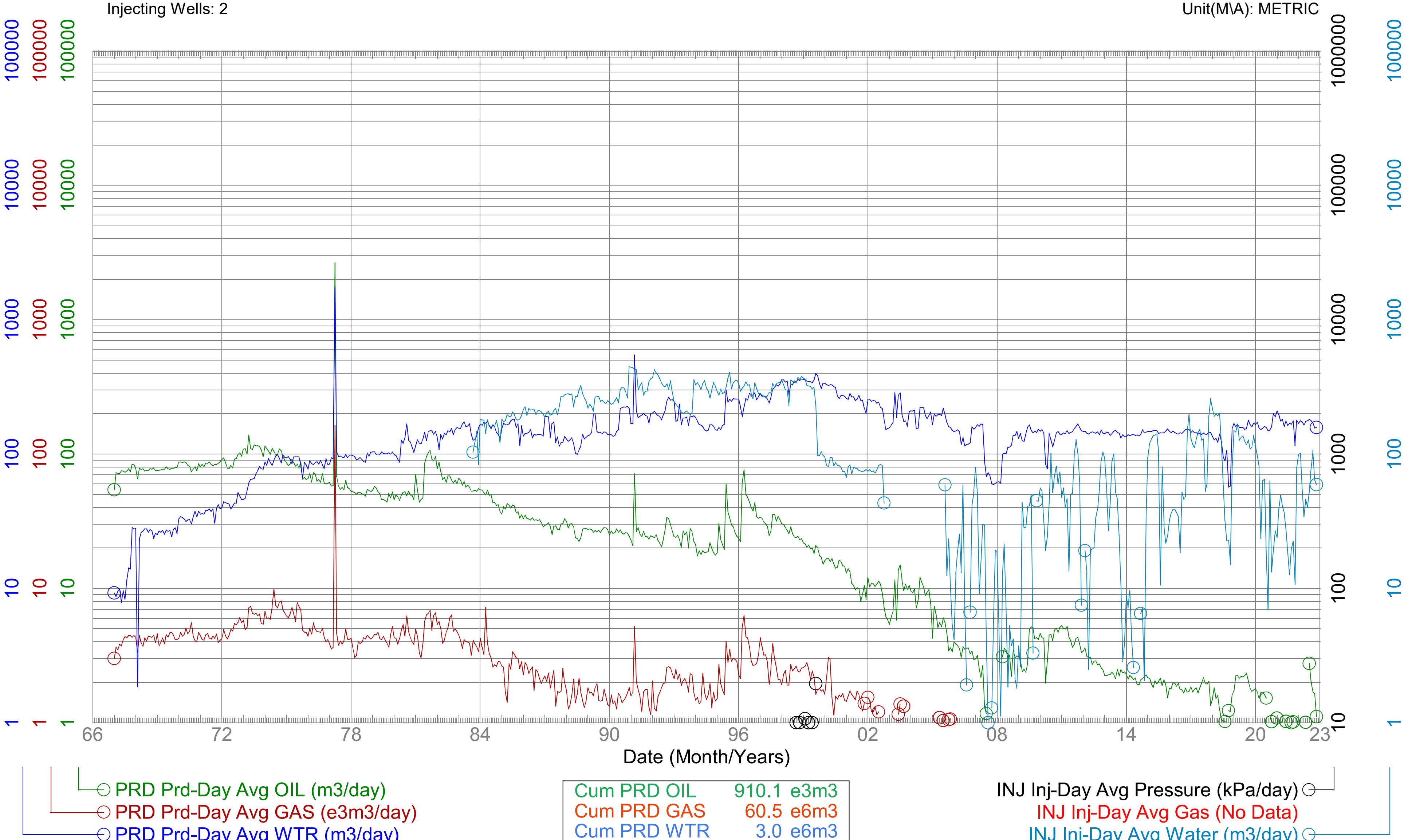
www.geologic.com

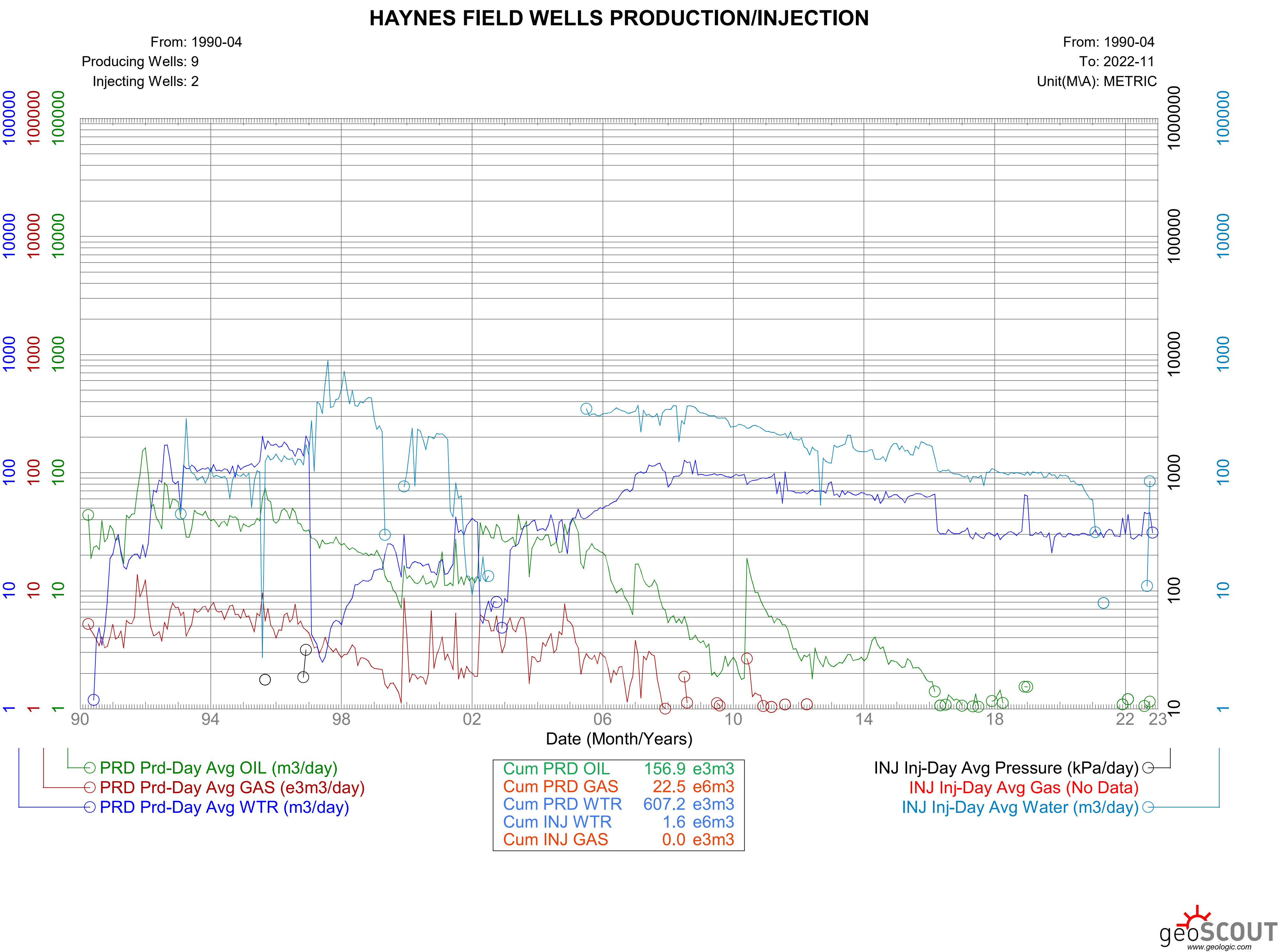
GHOST PINE FIELD WELLS PRODUCTION/INJECTION

From: 1961-12
Producing Wells: 17
Injecting Wells: 2

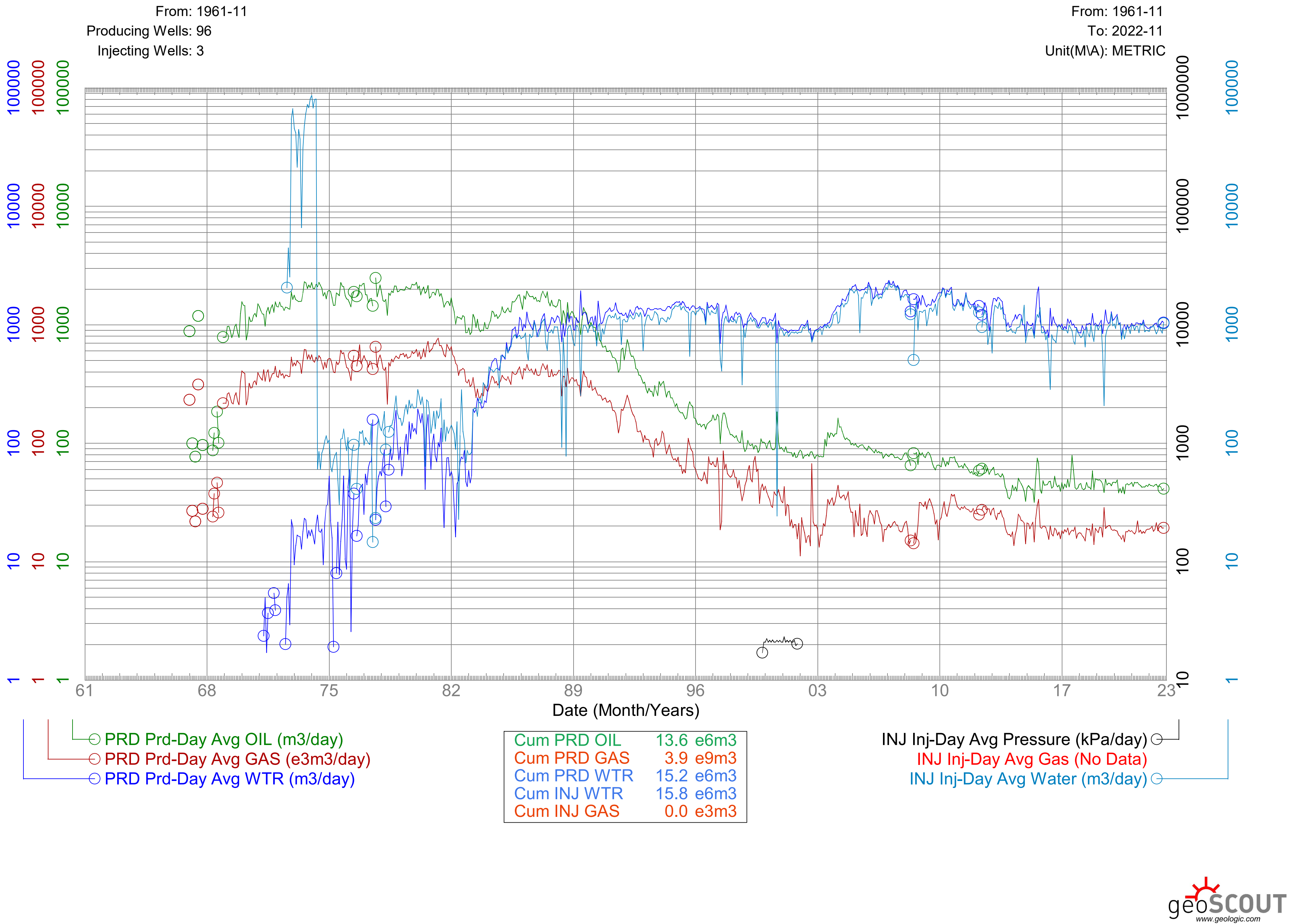
From: 1961-12
To: 2022-11
Unit(M\A): METRIC



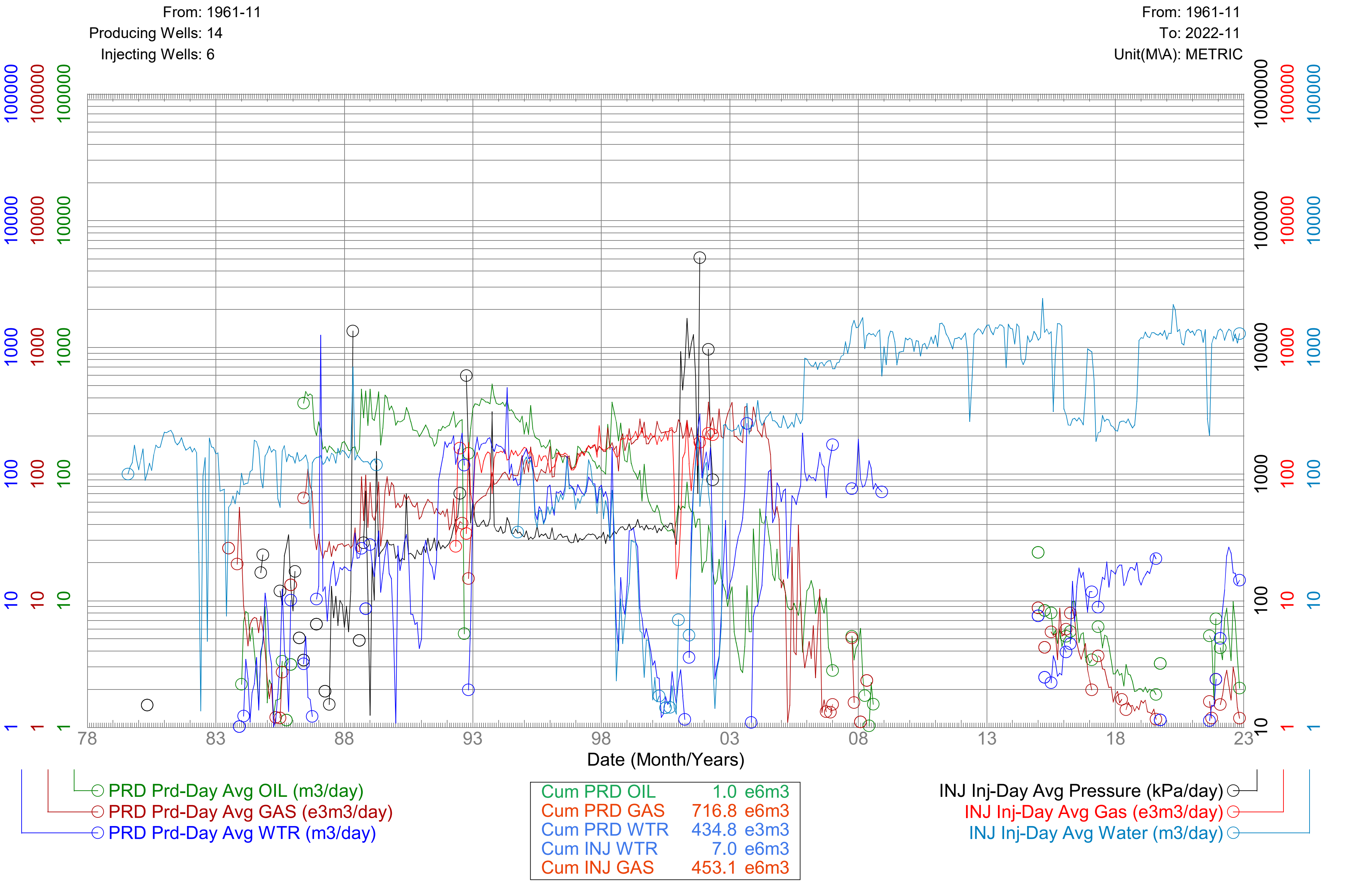
Cum PRD OIL	910.1	e3m3
Cum PRD GAS	60.5	e6m3
Cum PRD WTR	3.0	e6m3
Cum INJ WTR	2.0	e6m3
Cum INJ GAS	0.0	e3m3


HAYNES FIELD WELLS PRODUCTION/INJECTION
From: 1990-04
Producing Wells: 9
Injecting Wells: 2
From: 1990-04
To: 2022-11
Unit(M\A): METRIC
Date (Month/Years)
90
94
98
02
06
10
14
18
22
23
PRD Prd-Day Avg OIL (m3/day)
PRD Prd-Day Avg GAS (e3m3/day)
PRD Prd-Day Avg WTR (m3/day)
Cum PRD OIL 156.9 e3m3
Cum PRD GAS 22.5 e6m3
Cum PRD WTR 607.2 e3m3
Cum INJ WTR 1.6 e6m3
Cum INJ GAS 0.0 e3m3
INJ Inj-Day Avg Pressure (kPa/day)
INJ Inj-Day Avg Gas (No Data)
INJ Inj-Day Avg Water (m3/day)
geoSCOUT
www.geologic.com

INNISFAIL FIELD WELLS PRODUCTION/INJECTION



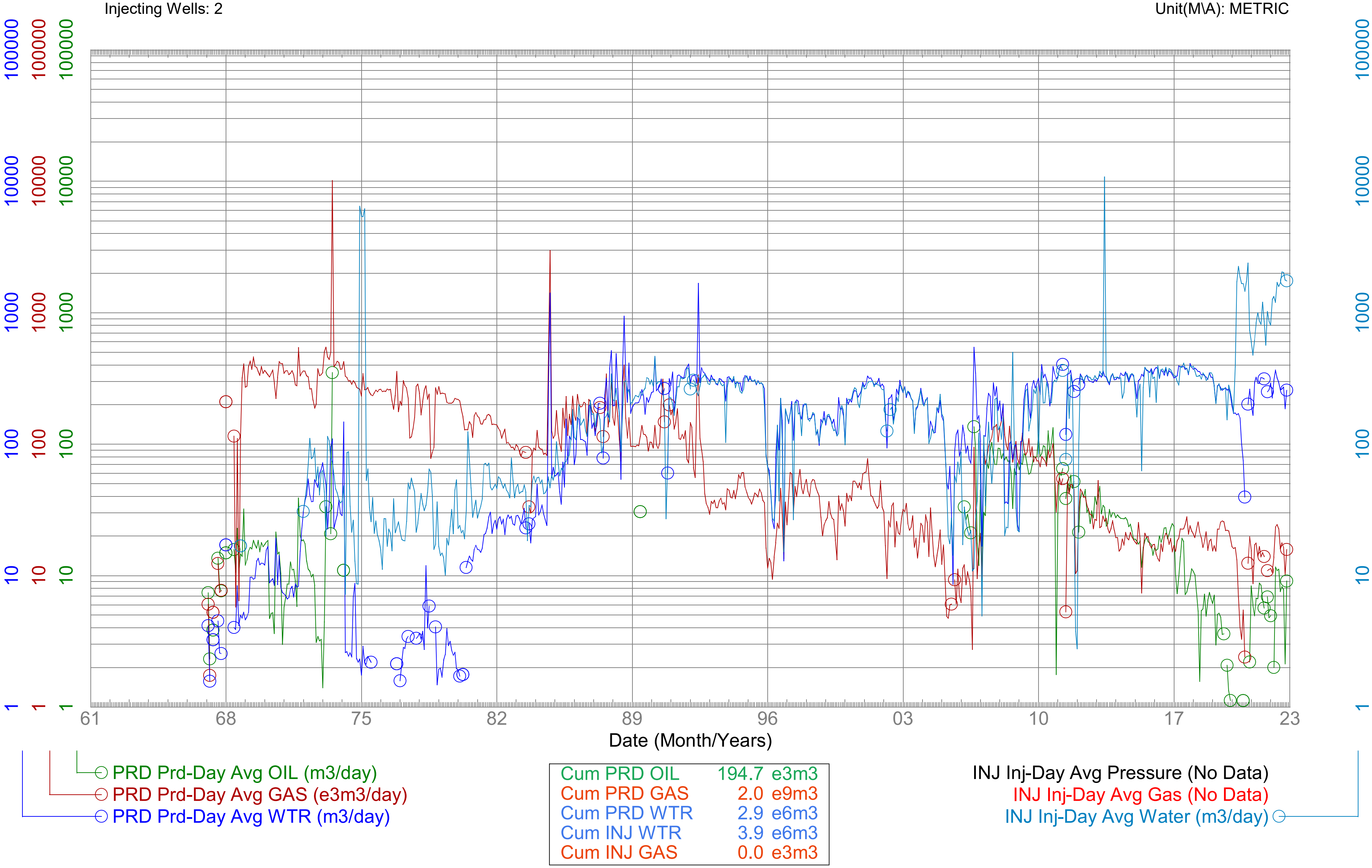
JOFFRE FIELD WELLS PRODUCTION/INJECTION



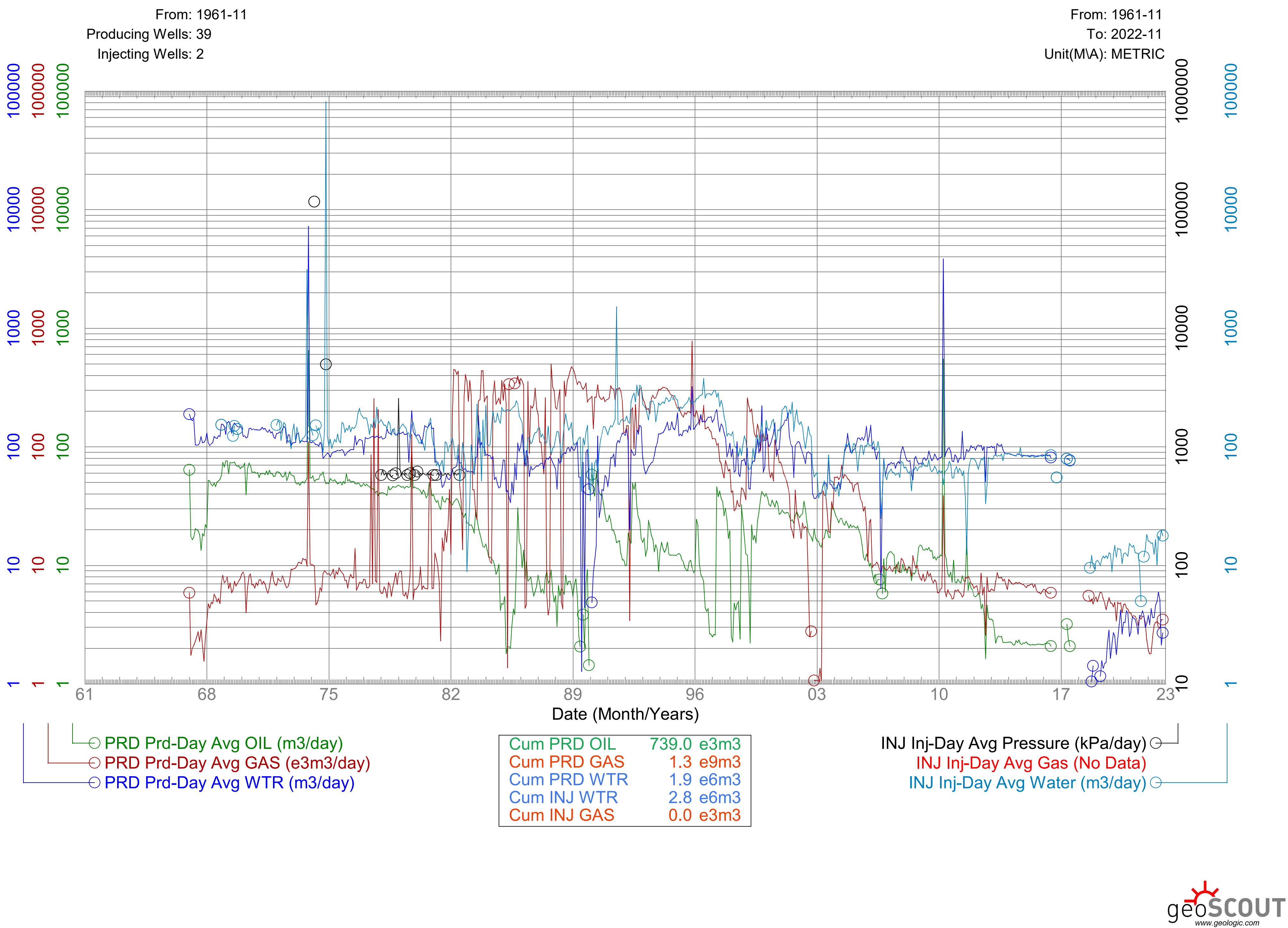
LONE PINE CREEK FIELD WELLS PRODUCTION/INJECTION

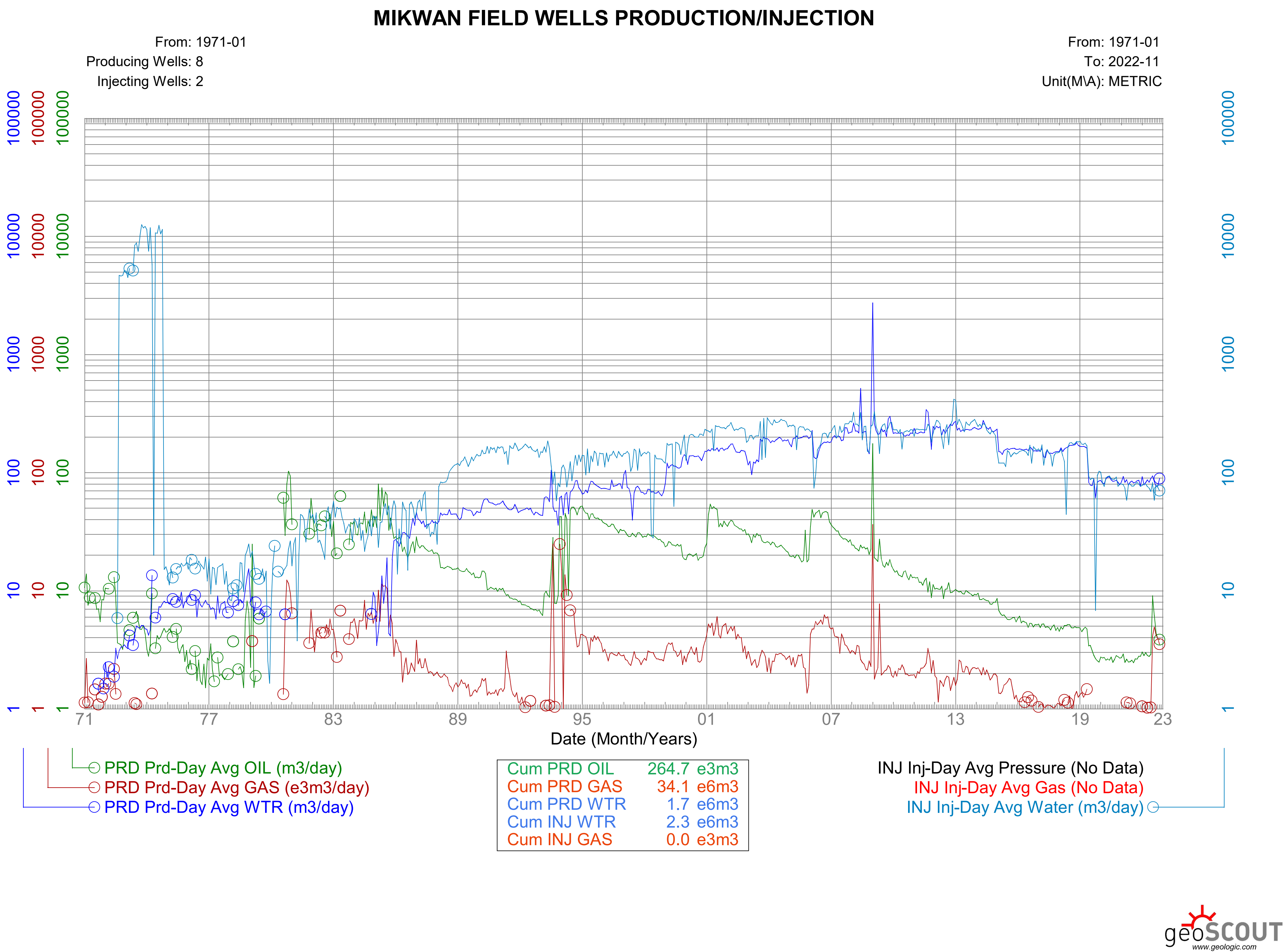
From: 1961-12
Producing Wells: 15
Injecting Wells: 2

From: 1961-12
To: 2022-11
Unit(M\A): METRIC



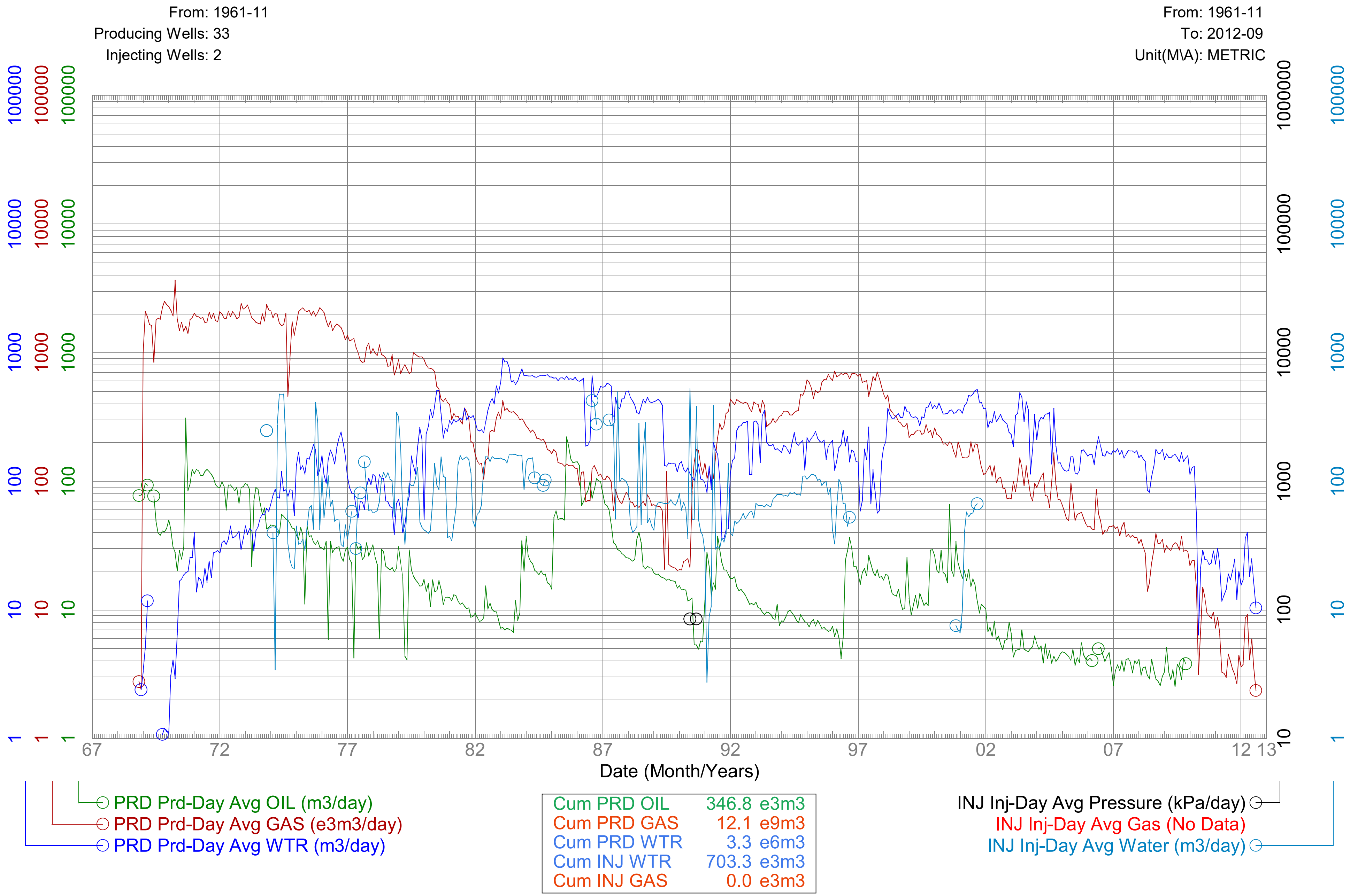
MALMO FIELD WELLS PRODUCTION/INJECTION





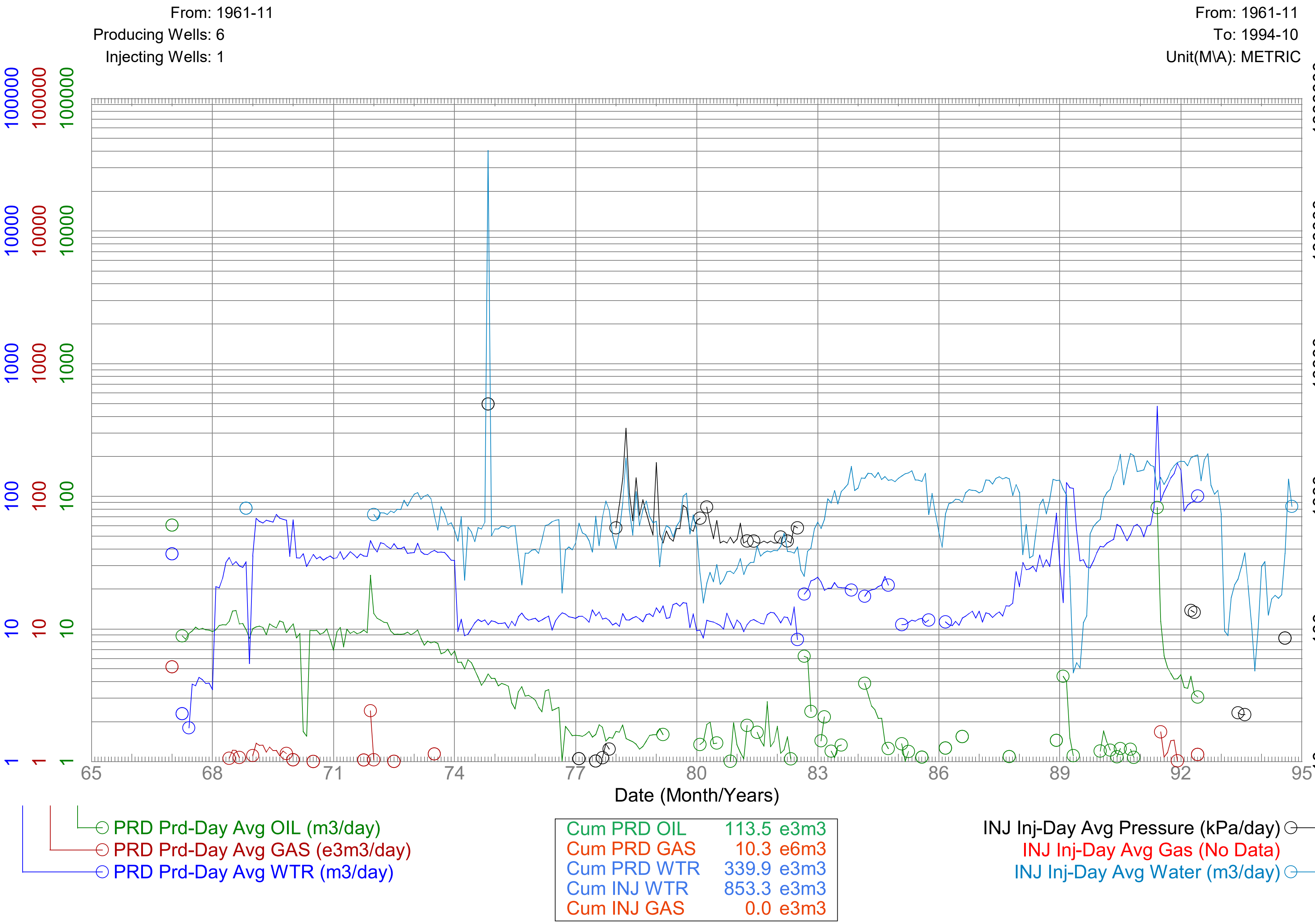
MIKWAN FIELD WELLS PRODUCTION/INJECTION
From: 1971-01
Producing Wells: 8
Injecting Wells: 2
From: 1971-01
To: 2022-11
Unit(M\A): METRIC
100000
10000
1000
100
10
1
71
77
83
89
95
01
07
13
19
23
Date (Month/Years)
PRD Prd-Day Avg OIL (m3/day)
PRD Prd-Day Avg GAS (e3m3/day)
PRD Prd-Day Avg WTR (m3/day)
Cum PRD OIL 264.7 e3m3
Cum PRD GAS 34.1 e6m3
Cum PRD WTR 1.7 e6m3
Cum INJ WTR 2.3 e6m3
Cum INJ GAS 0.0 e3m3
INJ Inj-Day Avg Pressure (No Data)
INJ Inj-Day Avg Gas (No Data)
INJ Inj-Day Avg Water (m3/day)
geoSCOUT
www.geologic.com

NEVIS FIELD WELLS PRODUCTION/INJECTION



geoSCOUT
www.geologic.com

NEW NORWAY FIELD WELLS PRODUCTION/INJECTION

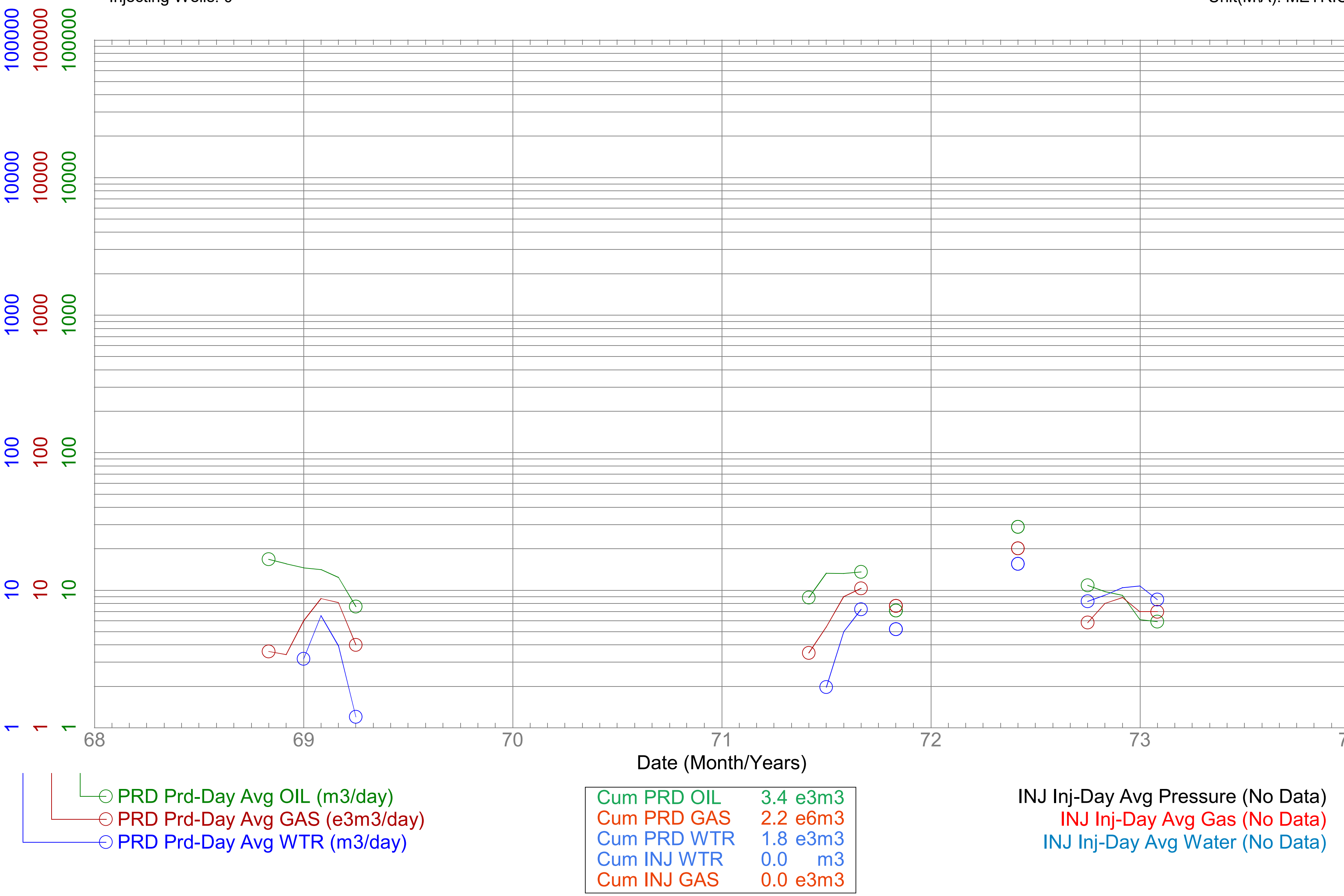


geoSCOUT www.geologic.com

PENHOLD FIELD WELLS PRODUCTION/INJECTION

From: 1968-11
Producing Wells: 1
Injecting Wells: 0

From: 1968-11
To: 1973-02
Unit(M\A): METRIC



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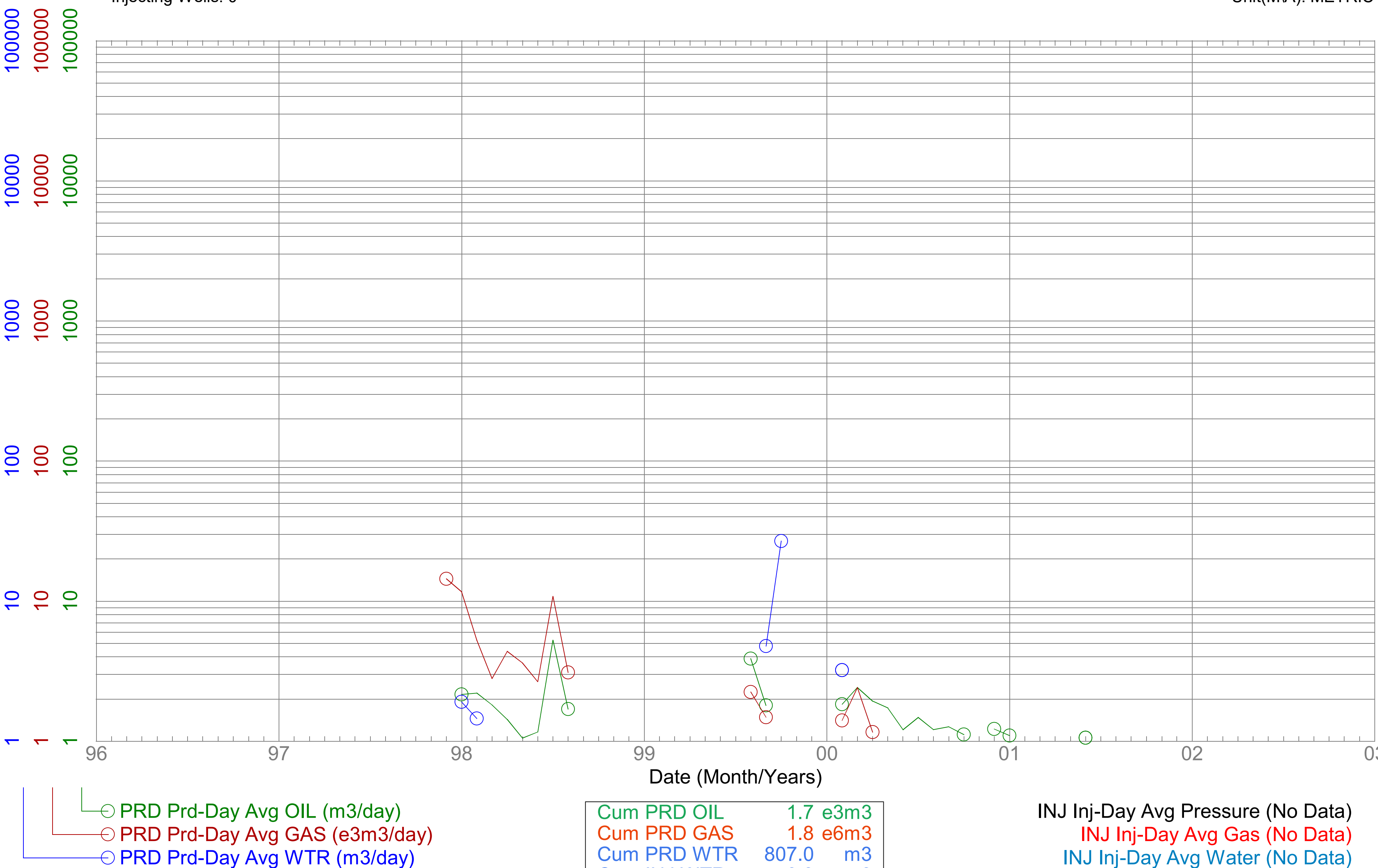
SWALWELL FIELD WELLS PRODUCTION/INJECTION

From: 1961-11
Producing Wells: 2
Injecting Wells: 0

From: 1961-11
To: 2002-01
Unit(M\A): METRIC



Cum PRD OIL	1.7	e3m3
Cum PRD GAS	1.8	e6m3
Cum PRD WTR	807.0	m3
Cum INJ WTR	0.0	m3
Cum INJ GAS	0.0	e3m3

INJ Inj-Day Avg Pressure (No Data)
INJ Inj-Day Avg Gas (No Data)
INJ Inj-Day Avg Water (No Data)

geoSCOUT
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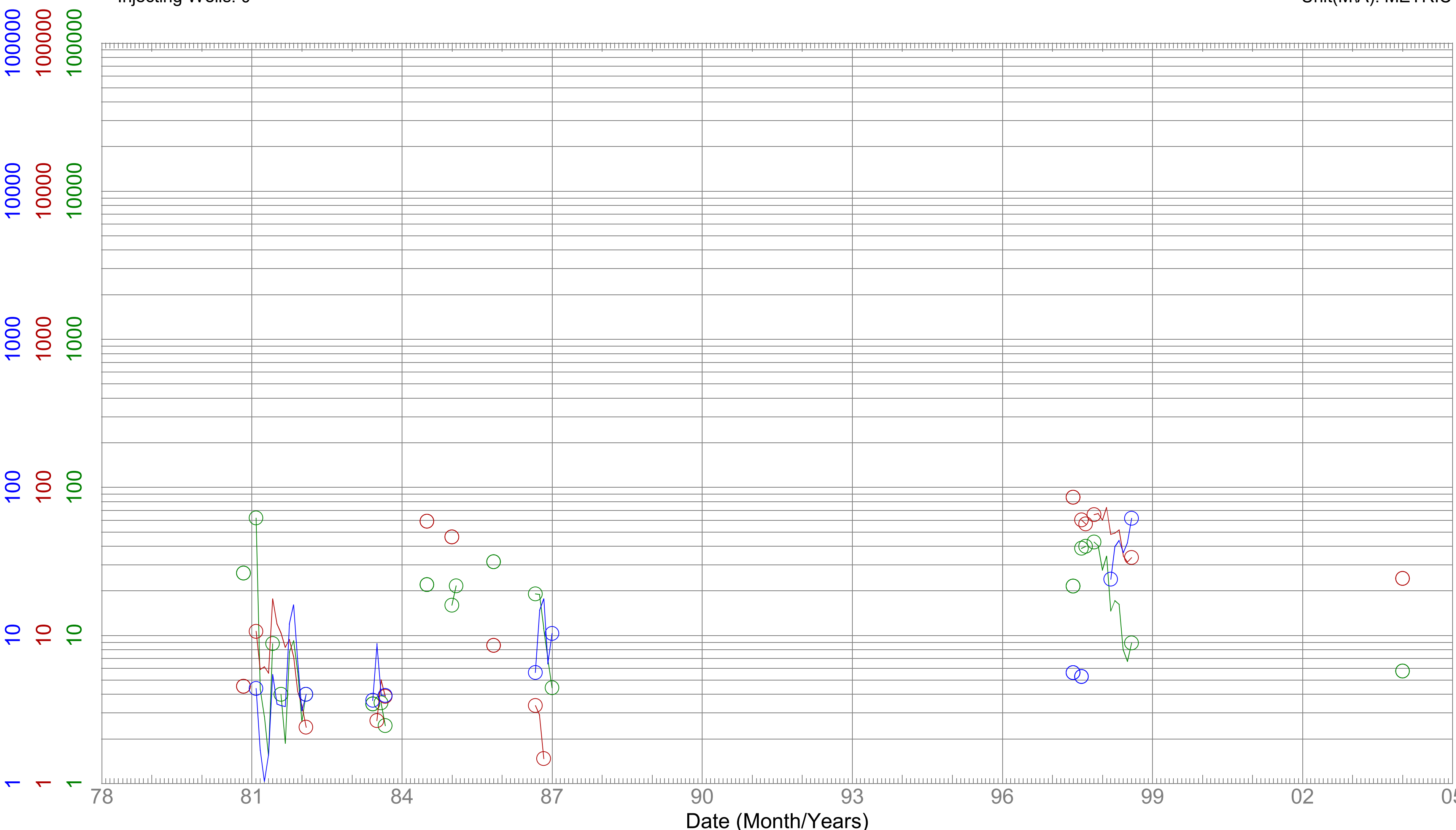
THREE HILLS CREEK FIELD WELLS PRODUCTION/INJECTION

From: 1961-11
Producing Wells: 6
Injecting Wells: 0

From: 1961-11
To: 2004-02
Unit(M\A): METRIC



PRD Prd-Day Avg OIL (m3/day)
PRD Prd-Day Avg GAS (e3m3/day)
PRD Prd-Day Avg WTR (m3/day)

Cum PRD OIL	9.4 e3m3
Cum PRD GAS	18.2 e6m3
Cum PRD WTR	8.7 e3m3
Cum INJ WTR	0.0 m3
Cum INJ GAS	0.0 e3m3

INJ Inj-Day Avg Pressure (No Data)
INJ Inj-Day Avg Gas (No Data)
INJ Inj-Day Avg Water (No Data)

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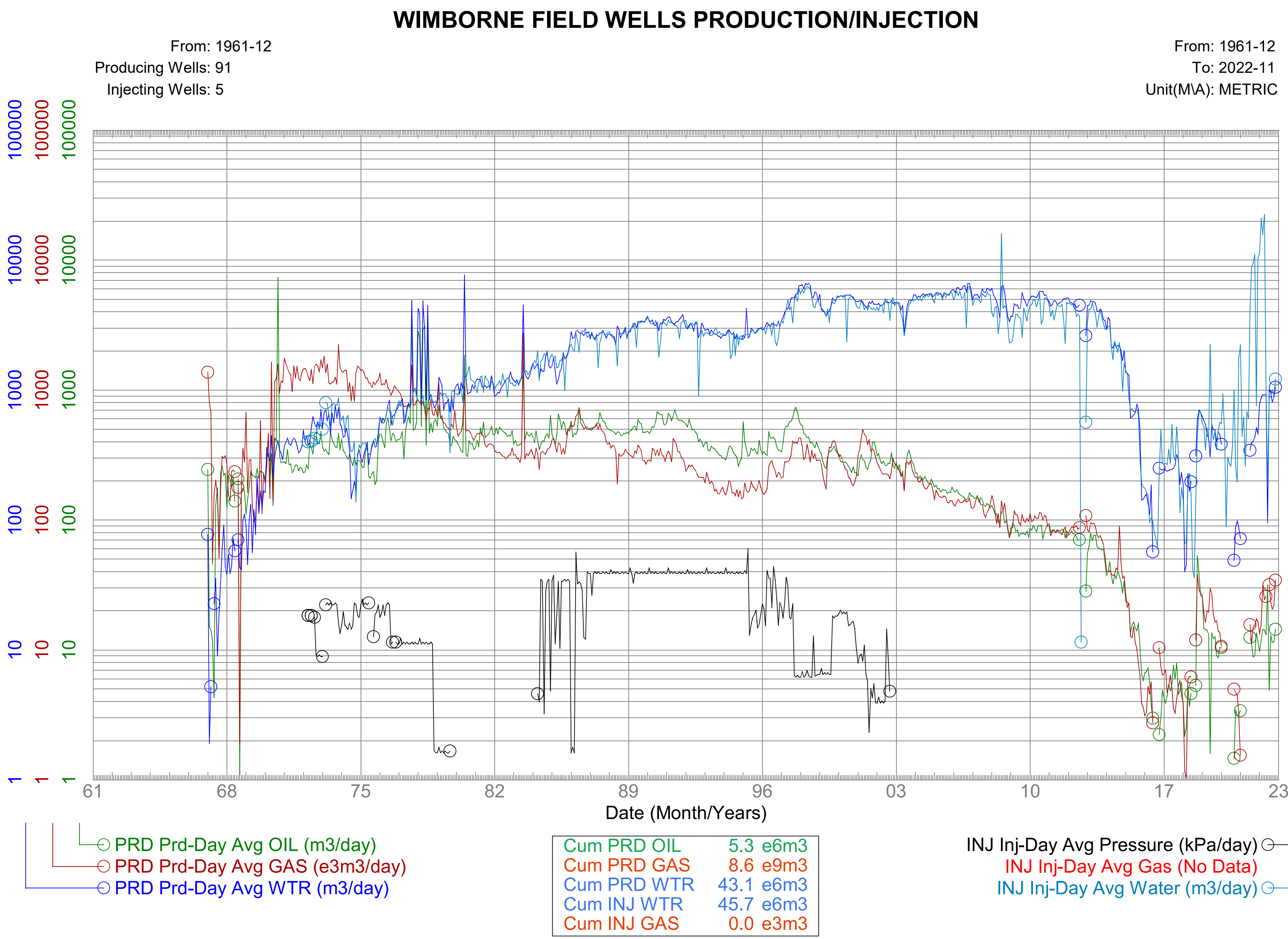
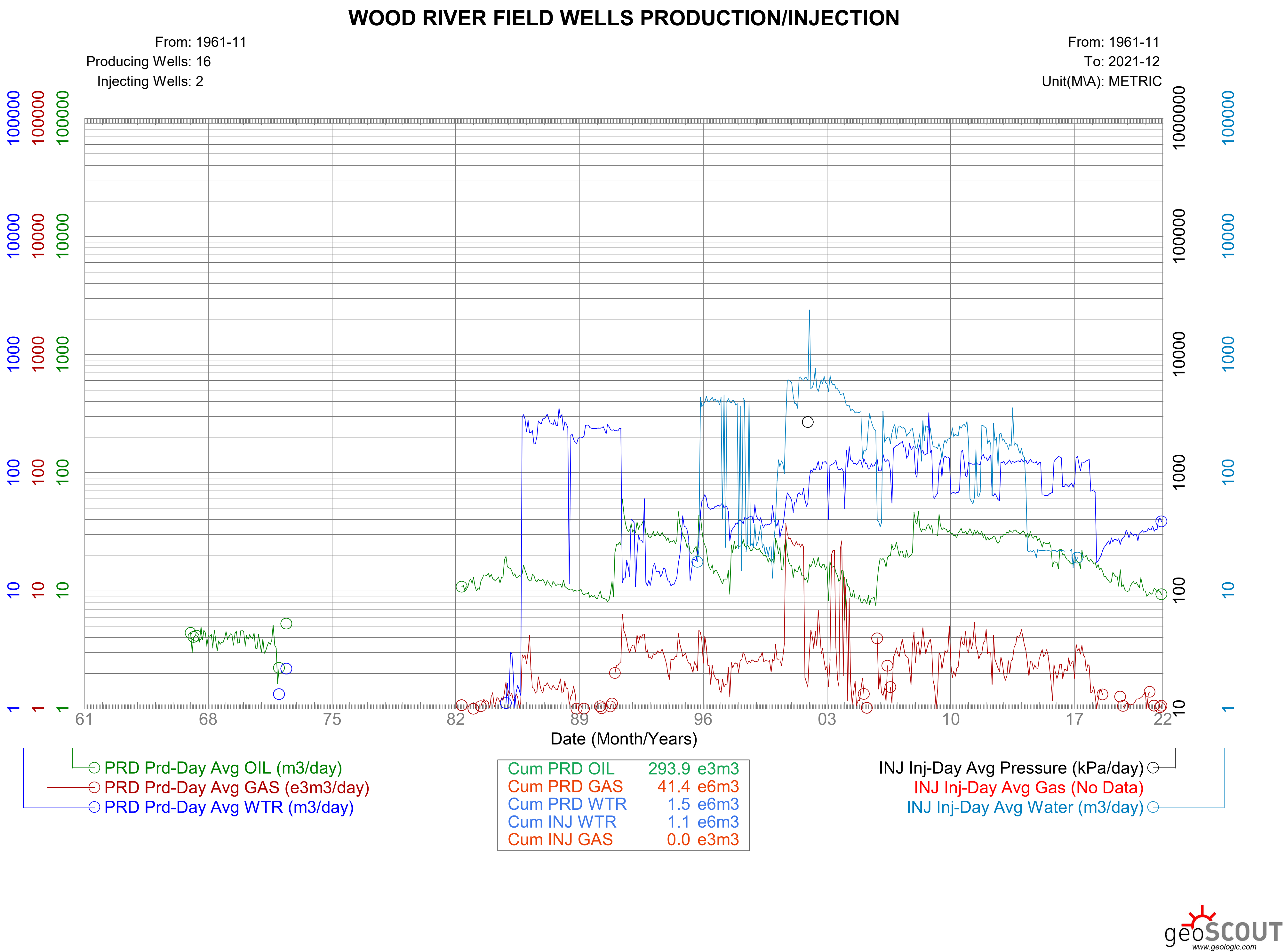


WIMBORNE FIELD WELLS PRODUCTION/INJECTION
From: 1961-12
Producing Wells: 91
Injecting Wells: 5
From: 1961-12
To: 2022-11
Unit(M\A): METRIC
Date (Month/Years)
61
68
75
82
89
96
03
10
17
23
PRD Prd-Day Avg OIL (m3/day)
PRD Prd-Day Avg GAS (e3m3/day)
PRD Prd-Day Avg WTR (m3/day)
Cum PRD OIL 5.3 e6m3
Cum PRD GAS 8.6 e9m3
Cum PRD WTR 43.1 e6m3
Cum INJ WTR 45.7 e6m3
Cum INJ GAS 0.0 e3m3
INJ Inj-Day Avg Pressure (kPa/day)
INJ Inj-Day Avg Gas (No Data)
INJ Inj-Day Avg Water (m3/day)



WOOD RIVER FIELD WELLS PRODUCTION/INJECTION
From: 1961-11
Producing Wells: 16
Injecting Wells: 2
From: 1961-11
To: 2021-12
Unit(M\A): METRIC
Date (Month/Years)
61
68
75
82
89
96
03
10
17
22
1
10
100
1000
10000
100000
1000000
PRD Prd-Day Avg OIL (m3/day)
PRD Prd-Day Avg GAS (e3m3/day)
PRD Prd-Day Avg WTR (m3/day)
Cum PRD OIL 293.9 e3m3
Cum PRD GAS 41.4 e6m3
Cum PRD WTR 1.5 e6m3
Cum INJ WTR 1.1 e6m3
Cum INJ GAS 0.0 e3m3
INJ Inj-Day Avg Pressure (kPa/day)
INJ Inj-Day Avg Gas (No Data)
INJ Inj-Day Avg Water (m3/day)
geoSCOUT
www.geologic.com

POOL	VRR	Net Producing
ALL BASHAW	0.398551	Net Injecting
ALIX	0	
BASHAW	0.554177	
CHIGWELL NORTH	0	
CHIGWELL	1.760946	
CLIVE	0.635604	
DUHAMEL	1.884367	
Erskine	0	
GHOST PINE	0.457712	
HAYNES	1.765363	
INNISFAIL	0.297207	
JOFFRE	1.685638	
LONE PINE CREEK	0.270255	
MALMO	0.281019	
MIKWAN	1.069614	
NEVIS	0.009536	
NEW NORWAY	1.621446	
PENHOLD	0	
SWALWELL	0	
THREE HILLS CREEK	0	
WIMBORNE	0.460774	
WOOD RIVER	0.541395	

SGS	Geochemistry Lakefield Laboratory	Doc Type **Method Summary** Method Code **GC_SOL91T** Service **Testing** Issued Date **June 2021**
Natural Resources	Multi-Element Preparation and Determination of Aqueous solutions by ICP-OES [Ag, Al, As, Ba, Be, Bi, Ca, Cd, Co, Cr, Cu, Fe, K, Li, Mg, Mn, Mo, Na, Ni, P, Pb, Sb, Se, Sn, Sr, Tl, Ti, V, W, Y, Zn] Note: B, Ga, Ge, In, Nb, Re, Sc, Si, Ta, Te, U, Zr can be added as additions.	Approved by **S. Meyers**

1. **Parameter(s) measured, unit(s):**
   Silver (Ag), Aluminum (Al), Arsenic (As), Barium (Ba), Beryllium (Be), Bismuth (Bi), Calcium (Ca), Cadmium (Cd), Cobalt (Co), Chromium (Cr), Copper (Cu), Iron (Fe), Potassium (K), Lithium (Li), Magnesium (Mg), Manganese (Mn), Molybdenum (Mo), Sodium (Na), Nickel (Ni), Phosphorus (P), Lead (Pb), Antimony (Sb), Selenium (Se), Tin (Sn), Strontium (Sr), Thallium (Tl), Titanium (Ti), Vanadium (V), Tungsten (W), Yttrium (Y), and Zinc (Zn) in mg/L.
   Boron (B), Gallium (Ga), Germanium (Ge), Indium (In), Niobium (Nb), Rhenium (Re), Scandium (Sc), Silica (Si), Tantalum (Ta), Tellerium (Te), Uranium (U), and Zirconium (Zr) in mg/L can be added as additional elements but are not part of the typical package.

2. **Typical sample size:**
   10 mL

3. **Type of sample applicable (media):**
   Aqueous (non-cyanide) process solutions.

4. **Sample preparation technique used:**
   Samples are diluted into specific acids depending upon the acid/base matrix of the incoming solution and generally diluted 10x, 100x and 5000x into an acid matrix.

5. **Method of analysis used:**
   Aqueous (non-cyanide) process solutions are diluted within the linear range of the instrument calibration and according to their acid or base matrix and analyzed by the ICP-OES system.

6. **Data reduction by:**
   Computer, on line, data fed to Laboratory Information Management System with secure audit trail.

7. **Figures of Merit:**

This method has been fully validated for the range of samples typically analyzed. Method validation includes the use of reference materials, replicates, duplicates and blanks to calculate accuracy, precision, linearity, range, limit of detection, reporting limit, specificity and measurement uncertainty.

The estimated Measurement Uncertainty (MU) has been established for the following parameters at various concentration ranges. The estimated MU is assessed using reference materials, and replicate samples or duplicate samples (comprising of different samples, analysts, laboratory conditions, equipment, etc.,) over a period of greater than 3 months.

Where insufficient live sample data is available to calculate the estimated MU, a theoretical estimate is provided in blue.

Concentration Range	**Estimated Measurement Uncertainty (MU) +/- (relative percent)**														
	Ag	Al	As	Ba	Be	Bi	Ca	Cd	Co	Cr	Cu	Fe	K	Li	Mg
Lower Limit (mg/L)	0.08	0.2	3	0.007	0.002	1	0.9	0.09	0.3	0.1	0.1	0.2	1	2	0.07
0.001-<0.005 mg/L	NA	NA	NA	NA	88	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
0.005-<0.01 mg/L	NA	NA	NA	72	38	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
0.01-<0.05 mg/L	NA	NA	NA	22	13	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
0.05-<0.1 mg/L	105	NA	NA	12	8.3	NA	NA	105	NA	NA	NA	NA	NA	NA	72
0.1-<0.5 mg/L	30	72	NA	6.7	5.8	NA	NA	30	72	30	30	55	NA	NA	22
0.5-<1.0 mg/L	15	32	NA	5.7	5.3	NA	105	15	32	15	15	25	NA	NA	12
1-<5 mg/L	7.5	12	72	5.2	5.1	30	30	7.5	12	7.5	7.5	10	22	55	6.7
5-<10 mg/L	6.0	7.7	32	5.1	5.0	15	15	6.0	7.7	6.0	6.0	7.0	12	25	5.7
10-<50 mg/L	5.3	5.7	12	5.0	5.0	7.5	7.5	5.3	5.7	5.3	5.3	5.5	6.7	10	5.2
50-<100 mg/L	5.1	5.3	7.7	5.0	5.0	6.0	6.0	5.1	5.3	5.1	5.1	5.2	5.7	7.0	5.1
100-<500 mg/L	5.0	5.1	5.7	5.0	5.0	5.3	5.3	5.0	5.1	5.0	5.0	5.1	5.2	5.5	5.0
500-<1000 mg/L	5.0	5.0	5.3	5.0	5.0	5.1	5.1	5.0	5.0	5.0	5.0	5.0	5.1	5.2	5.0
1000-<5000 mg/L	5.0	5.0	5.1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.1	5.0
>5000 mg/L	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

Concentration Range	**Estimated Measurement Uncertainty (MU) +/- (relative percent)**														
	Mn	Mo	Na	Ni	P	Pb	Sb	Se	Sn	Sr	Ti	Tl	V	Y	Zn
Lower Limit (mg/L)	0.04	0.6	2	0.6	5	2	1	3	2	0.002	0.02	3	0.2	0.02	0.7
0.001-<0.005 mg/L	NA	NA	NA	NA	NA	NA	NA	NA	NA	88	NA	NA	NA	NA	NA
0.005-<0.01 mg/L	NA	NA	NA	NA	NA	NA	NA	NA	NA	38	NA	NA	NA	NA	NA
0.01-<0.05 mg/L	88	NA	NA	NA	NA	NA	NA	NA	NA	13	47	NA	NA	63	NA
0.05-<0.1 mg/L	38	NA	NA	NA	NA	NA	NA	NA	NA	8.3	22	NA	NA	28	NA
0.1-<0.5 mg/L	13	NA	NA	NA	NA	NA	NA	NA	NA	5.8	9.2	NA	55	11	NA
0.5-<1.0 mg/L	8.3	72	NA	72	NA	NA	NA	NA	NA	5.3	6.7	NA	25	7.3	105
1-<5 mg/L	5.8	22	47	22	NA	47	38	72	55	5.1	5.4	72	10	5.6	30
5-<10 mg/L	5.3	12	22	12	72	22	18	32	25	5.0	5.2	32	7.0	5.2	15

10-<50 mg/L	5.1	6.7	9.2	6.7	22	9.2	8.3	12	10	5.0	5.0	12	5.5	5.1	7.5
50-<100 mg/L	5.0	5.7	6.7	5.7	12	6.7	6.3	7.7	7.0	5.0	5.0	7.7	5.2	5.0	6.0
100-<500 mg/L	5.0	5.2	5.4	5.2	6.7	5.4	5.3	5.7	5.5	5.0	5.0	5.7	5.1	5.0	5.3
500-<1000 mg/L	5.0	5.1	5.2	5.1	5.7	5.2	5.1	5.3	5.2	5.0	5.0	5.3	5.0	5.0	5.1
1000-<5000 mg/L	5.0	5.0	5.0	5.0	5.2	5.0	5.0	5.1	5.1	5.0	5.0	5.1	5.0	5.0	5.0
5000-<10000 mg/L	5.0	5.0	5.0	5.0	5.1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
>10000 mg/L	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

** Note: Measurement Uncertainty estimates may vary from location to location due to dependency on instrumentation

The reported uncertainty is expanded using a coverage factor k=2 for a level of confidence of approximately 95%, assuming a normal distribution

Note: Report limits may be elevated for difficult matrices

8. **Quality control:**
   Quality control materials include duplicates and are randomly inserted with the frequency set according to method protocols at ~18% for process control. Quality control materials will also include spikes every 24 samples or less. Calibration materials and secondary source solutions to cover the analytical range of ICP-OES analysis; reagent blank and drift check materials every 15 samples.

9. **Accreditation:**
   SGS Natural Resources conforms to the requirements of ISO/IEC 17025. Scopes of Accredited tests are site specific, please visit https://www.scc.ca/en/search/laboratories

SMEE & ASSOCIATES CONSULTING LTD.
CONSULTING GEOCHEMISTRY / GEOLOGY

Certificate of Analysis

E3 Metals Standard Dissolved Li in Brine

Element	Certified Mean	Two Standard Deviations (between lab)
Li in Brine, ICP	**76.1 mg/l**	**6.4 mg/l**

The mean and standard deviation for Li in brine was calculated from data supplied by seven laboratories, but because of large variations in results due to different analytical methods being used, only data from four of the laboratories were used in the final statistics. The preferred method of analysis was a direct aspiration of the brine into an ICP-OES.

The participating laboratories were:

AGAT, Calgary
ALS, Vancouver
BV Environment, Vancouver
SGS Mineral, Lakefield
SGS Environment, Lakefield
CARO, Calgary
BV Environmental, Calgary

The final limits were calculated after first determining if all data was compatible within a spread normally expected for similar analytical methods done by reputable laboratories. Complete laboratory data was removed if that laboratory failed a t test of means compared to the remaining laboratories. Individual data from any laboratory was removed from further calculations when an assay failed a Grubbs test compared to the remainder of the analyses. The means and standard deviations were calculated using all remaining data. Any analysis that fell outside of the mean ±2 standard deviations was removed from the ensuing data base. The mean and standard deviations were again calculated using the remaining data.

This method is different from that used by Government agencies in that the actual "between-laboratory" standard deviation is used in the calculations. This produces upper and lower limits that reflect actual individual analyses rather than a grouped set of analyses. The limits can therefore be used to monitor accuracy from individual analyses, unlike the Confidence Limits published on other standards. Standards with an RSD of near or less than 5 % are certified, RSD's of between near 5 % and 15 % are Provisional and should be used with care, and RSD's over 15 % or that have insufficient data are Indicated and cannot be used to monitor accuracy of a single analysis.

The bulk standards brine standards were supplied by E3 Metals of Calgary.

BW Smee

Barry W. Smee, Ph.D., P.Geo., FGC
March, 2022

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E3 Metals Corp. Standard Operating Procedure for Field Sampling - Current as of April 2022

In Advance:

1	Prepare sampling program in Excel (Sampling > Schedules)
2	Coordinate sampling dates and times using UWI and contact list provided by E3 Metals
3	Plan sampling schedule & understand requirements for site access and access for sampling points
4	Review your internal company SOG/SOP and E3 SOP sampling procedures and methodology
5	Comply with your internal and the operator's HS&E practices (ie. Complete orientations in advance)
6	Obtain Laboratory supplied (1L glass amber bottles or jars) -3 per well; obtain E3 Metals custody seals
7	Obtain sampling equipment, PPE, documentation forms
8	Check-in with operator to ensure site access & timing works
9	Determine if sampling access point is at wellhead, battery, multi-well test separator, etc.
10	Confirm sampling access requirements (confined space, line pressure etc)
11	**Read Chain of Custody Description (E3 Metals Document)**

In the Field:

1	Determine the level of H2S at the sampling site. If >10ppm, take appropriate safety precautions (ie. Wear H2S kit); identify samples contain H2S in COC
2	As part of the April 2022 sampling program additonal gas, TOC and TPHC samples are requested which may contain preservatives. **If preservative testing is required, DO NOT ADD NITRIC preservative in the field (potential for combustion in the presence of H2S)**
3	Pre-rinse sample bottles in brine water
4	Discharge brine into pre-rinsed and pre-labelled opaque glass sample bottles (collect 3L produced water in total, minimum three 1L bottles per well is requested for spring program); see below for variance
5	Fill sample bottles to the top to eliminate trapped air at the top. If using a top-up bottle, ensure the top-up bottle is new and pre-rinsed.
6	Screw on cap & seal cap with electrical tape and **E3 Metals' custody seals**
7	Attach E3 sample label provided with unique ID
8	Fill out Field Sample Sheet (E3 Metals Document)
9	Make notes if anything unusual occurs (odors, colours, ppt, gas) or on necessary deviations from SOP
10	When samples need to be kept overnight before delivery, store them in a sealed and locked storage container at room temperature with their chain of custody documentation. If there is a risk of expansion in the sample (emulsion and/or oil), samples may be kept cool to mitigate any risk of bottle explosion.
11	One person should make notes at the time or as soon as possible thereafter (in waterproof ink)
12	Do not filter samples
	Complete COC; Keep samples from each location together (freezer bag?) and in one shipping container. More than one sample location can be in one shipping container; Only one COC per shipping container(cooler) keep copy or photograph of COC
13	Deliver or ship samples to AGAT Calgary or BV Edmonton as required using Rebel Hotshot

Sample Point Specific Instructions:

	Single Well Test Separator
	Collect formation water directly from separator; identify or describe the sample access port
	Ask operator about whether **emulsifier (any other additive)** is added, and if so, collect information such as: where is it added, MSDS, concentration, etc.
	Multi-Well Test Separator
	Collect formation water directly from separator; identify or describe the sample access port
	Ask operator about whether **emulsifier (any other additive)** is added, and if so, collect information such as: where is it added, MSDS, concentration, etc.
	When sampling different wells from the same separator, a 24 hour flush is required between samples from different wells. Document when new well was placed on-line.
	Wellhead
	Double check to ensure the correct sampling port, and anticipated line pressure, gas and level of H2S. Review procedures and ensure sample can be safely collected. STOP if unexpected pressures, gas, or other conditions are encountered. Revise procedures or methods.
	Use enough sample containers to meet the total 3L (brine) volume requirements. If significant oil or emulsion (> 25%) decant saline water; if oil or emulsion (<25%) collect 4L of sample; if emulsion is stable collect 6L of sample.
	Ask operator about whether **emulsifier (any other additive)** is added, and if so, collect information such as: where is it added, MSDS, concentration, etc.
	Send oil-water emulsion sample to the lab to be separated
Note:	***H2S is potentially present at EVERY well. Take the required safety precautions. H2S should be removed in the field to the degree it is possible, and further removed in the laboratory through degassing in the ventalator and/or chlorination***

Title	Field Nm	Admin Pool	Original OIP(OOIP)(e3m3)
ALBERTA OIL POOL	Alix	D-3 A	107.3
ALBERTA OIL POOL	Bashaw	D-3 B	658.3
ALBERTA OIL POOL	Bashaw	D-3 D	5.4
ALBERTA OIL POOL	Chigwell	D-3 A	84.4
ALBERTA OIL POOL	Chigwell	D-3 B	639.1
ALBERTA OIL POOL	Chigwell	D-3 F	4.6
ALBERTA OIL POOL	Chigwell	D-3 G	93
ALBERTA OIL POOL	Chigwell	D-3 H	5.8
ALBERTA OIL POOL	Clive	D-3 A	12213.3
ALBERTA OIL POOL	Clive	D-3 A	12340.5
ALBERTA OIL POOL	Chigwell North	D-3 A	24.1
ALBERTA OIL POOL	Chigwell North	D-3 B	130.5
ALBERTA OIL POOL	Chigwell North	D-3 C	376.8
ALBERTA OIL POOL	Chigwell North	D-3 D	139.8
ALBERTA OIL POOL	Duhamel	D-3 A	191.1
ALBERTA OIL POOL	Duhamel	D-3 B	2238.4
ALBERTA OIL POOL	Haynes	D-3 B	389.2
ALBERTA OIL POOL	Haynes	D-3 C	107.5
ALBERTA OIL POOL	Haynes	D-3 D	187.4
ALBERTA OIL POOL	Joffre	D-3 A	30.3
ALBERTA OIL POOL	Joffre	D-3 B	1729.2
ALBERTA OIL POOL	Joffre	D-3 C	189.3
ALBERTA OIL POOL	Joffre	D-3 D	41.4
ALBERTA OIL POOL	Joffre	D-3 E	78.6
ALBERTA OIL POOL	Malmo	D-3 C	71.1
ALBERTA OIL POOL	Malmo	D-3 D	60
ALBERTA OIL POOL	Malmo	D-3 G	10.1
ALBERTA OIL POOL	Malmo	D-3 H	104.7
ALBERTA OIL POOL	Malmo	D-3 J	37.3
ALBERTA OIL POOL	Mikwan	D-3 A	339.1
ALBERTA OIL POOL	Mikwan	D-3 B	612.1
ALBERTA OIL POOL	Mikwan	D-3 C	20.7
ALBERTA OIL POOL	Nevis	D-3 B	238
ALBERTA OIL POOL	Nevis	D-3 C	220.1
ALBERTA OIL POOL	Nevis	D-3 D	192.1
ALBERTA OIL POOL	Nevis	D-3 F	200
ALBERTA OIL POOL	Nevis	D-3 G	239.6
ALBERTA OIL POOL	Nevis	D-3 H	18.9
ALBERTA OIL POOL	Nevis	D-3 I	7.5
ALBERTA OIL POOL	Nevis	D-3 J	110.2
ALBERTA OIL POOL	Nevis	D-3 K	6.9
ALBERTA OIL POOL	New Norway	D-3	317.8
ALBERTA OIL POOL	Penhold	D-3 A	182.8
ALBERTA OIL POOL	Swalwell	D-3 B	44
ALBERTA OIL POOL	Three Hills Creek	D-3 A	40.9
ALBERTA OIL POOL	Three Hills Creek	D-3 B	112.2

ALBERTA OIL POOL	Three Hills Creek	D-3 C	133.1
ALBERTA OIL POOL	Three Hills Creek	D-3 D	2.1
ALBERTA OIL POOL	Wimborne	D-3 A	13000.6
ALBERTA OIL POOL	Wood River	D-3 B	289.1
ALBERTA OIL POOL	Wood River	D-3 C	239
ALBERTA OIL POOL	Wood River	D-3 E	226.8
ALBERTA OIL POOL	Wood River	D-3 F	281
		TOTAL [e3m3]:	49,363
		B_o:	1.1
		Pore Volume OOIP [m3]:	54,299,410

Title	Field Nm	Admin Pool	Original GIP(OGIP)(e6m3)
ALBERTA GAS POOL	Innisfail	D-3	6279
ALBERTA GAS POOL	New Norway	D-3	15
ALBERTA GAS POOL	Wimborne	D-3 A	13846
ALBERTA GAS POOL	Clive	D-3 A	2464
ALBERTA GAS POOL	Lone Pine Creek	D-3 A	2051
ALBERTA GAS POOL	Lone Pine Creek	D-3 A	491
ALBERTA GAS POOL	Malmo	D-3 A	134
ALBERTA GAS POOL	Three Hills Creek	D-3 A	20
ALBERTA GAS POOL	Wood River	D-3 A	11
ALBERTA GAS POOL	Mikwan	D-3 A	10
ALBERTA GAS POOL	Joffre	D-3 A	4
ALBERTA GAS POOL	Duhamel	D-3 A	3
ALBERTA GAS POOL	Penhold	D-3 A	3
ALBERTA GAS POOL	Swalwell	D-3 A	3
ALBERTA GAS POOL	Alix	D-3 A	2
ALBERTA GAS POOL	Chigwell	D-3 A	2
ALBERTA GAS POOL	Malmo	D-3 B	1820
ALBERTA GAS POOL	Joffre	D-3 B	325
ALBERTA GAS POOL	Duhamel	D-3 B	128
ALBERTA GAS POOL	Bashaw	D-3 B	115
ALBERTA GAS POOL	Mikwan	D-3 B	61
ALBERTA GAS POOL	Lone Pine Creek	D-3 B	37
ALBERTA GAS POOL	Chigwell	D-3 B	31
ALBERTA GAS POOL	Innisfail	D-3 B	24
ALBERTA GAS POOL	Wood River	D-3 B	17
ALBERTA GAS POOL	Chigwell North	D-3 B	11
ALBERTA GAS POOL	Haynes	D-3 B	9
ALBERTA GAS POOL	Nevis	D-3 B	6
ALBERTA GAS POOL	Bashaw	D-3 C	97
ALBERTA GAS POOL	Chigwell North	D-3 C	46
ALBERTA GAS POOL	Haynes	D-3 C	15
ALBERTA GAS POOL	Wood River	D-3 C	14
ALBERTA GAS POOL	Joffre	D-3 C	6
ALBERTA GAS POOL	Three Hills Creek	D-3 C	5
ALBERTA GAS POOL	Nevis	D-3 C	3
ALBERTA GAS POOL	Malmo	D-3 C	2
ALBERTA GAS POOL	Wood River	D-3 D	20
ALBERTA GAS POOL	Haynes	D-3 D	8
ALBERTA GAS POOL	Malmo	D-3 D	6
ALBERTA GAS POOL	Nevis	D-3 D	3
ALBERTA GAS POOL	Malmo	D-3 E	43
ALBERTA GAS POOL	Nevis	D-3 E	36
ALBERTA GAS POOL	Chigwell	D-3 E	14
ALBERTA GAS POOL	Wood River	D-3 E	8
ALBERTA GAS POOL	Joffre	D-3 E	2
ALBERTA GAS POOL	Bashaw	D-3 E	1

ALBERTA GAS POOL	Malmo	D-3 F	49
ALBERTA GAS POOL	Wood River	D-3 F	18
ALBERTA GAS POOL	Nevis	D-3 F	3
ALBERTA GAS POOL	Nevis	D-3 G	9
ALBERTA GAS POOL	Chigwell	D-3 G	6
ALBERTA GAS POOL	Malmo	D-3 G	
ALBERTA GAS POOL	Malmo	D-3 H	7
ALBERTA GAS POOL	Malmo	D-3 I	24
ALBERTA GAS POOL	Nevis	D-3 I	
ALBERTA GAS POOL	Nevis	D-3 J	3

TOTAL [e6m3]:	28,370
B_g:	0.53
Pore Volume OGIP [m3]:	15,036,100,000