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Critical problems in the development of basin-hosted geothermal resources – considerations from the Western Canada Sedimentary Basin

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ABSTRACT

The exploration and development of low-enthalpy geothermal resources is now actively pursued in the Western Canada Sedimentary Basin, with at least five small commercial projects underway. Despite strong interest in development of these resources, none of the projects is close to commercial power production, and large-scale commercial investment has not yet materialized. In this paper, we identify critical problems that presently restrain development and identify research strategies for addressing those issues. Foremost among these problems are the lack of rigorous approaches to assessing risk and commercial value and the lack of risk mitigation strategies.

Rigorous consideration of value in basin-hosted geothermal resources is underpinned by geoscience and engineering. Commercial value is related to temperature and volume of hot water (or rock), flow rates, and concentrations of dissolved minerals, all which have been shown to vary spatially within basin-hosted geothermal fields. Spatial variability in these properties can be predicted through geophysical, petrophysical and geochemical models and characterized through geostatistical approaches. Dynamic models grounded in hydrologic and geochemical principles show that temporal variation can also be significant. Risk associated with predictions of resource size is related to sparse subsurface datasets and can be assessed and characterized with geoscience principles. Risk also results from feedback between production and reservoir systems and can include modifications to the reservoir or production system during production. For example, in carbonate-hosted geothermal fields, injection of cool spent water can dissolve reservoir rock, with possible consequences of early cold plume breakthrough from injection to production wells. Damage to reservoir rock can occur during injection operations and damage to production systems can occur through scaling. An additional class of risk is associated with real or perceived damage to the ground surface or stakeholder populations.

Risk mitigation primarily involves two types of assessment. First, it requires consideration of sources of uncertainty in valuation of the resource and identification of dataset that would reduce that uncertainty. For example, if there are gaps in the characterization of subsurface temperatures or flow rates, wells can be drilled to collect that data. Second, surveillance tools can provide real-time monitoring of reservoir behavior to identify developing problems and modify production systems before the problems impact resource values.

The oil and gas industry has for at least 30 years addressed problems in valuation of resources and assessment of risk through petroleum system analysis, developing approaches that are fundamentally grounded in geoscience. While a petroleum systems analysis may not directly translate to basin-hosted geothermal resources, many aspects of the basic framework can apply. The Tu Deh-Kah geothermal resource in northeastern British Columbia is hosted in Devonian Slave Point carbonates in a now depleted gas field and is currently being developed by the Fort Nelson First Nation (FNFN). Research groups at the University of Alberta and the University of British Columbia are now collaborating with the FNFN in studies to develop a "geothermal systems" approach for valuation and risk analysis. Results to date highlight several issues related to valuation and risk: (1) variability in water temperature at a field scale; (2) uncertainty in the extent, location and orientation of fracture systems that could affect water flow during production; (3) the presence of residual gas that may affect water flow in the reservoir and production systems; (4) the viability of repurposing existing oil and gas infrastructure for geothermal production.

1. INTRODUCTION

The Western Canada Sedimentary Basin (WCSB) is a major petroleum province that is now actively assessed for geothermal resources. The presence of hot water (greater than 100˚C) in porous and permeable sedimentary reservoirs (the term 'basin-hosted geothermal resources' is used in this paper) suggested to researchers as early as 2010 that commercial potential existed in the basin (e.g. Grasby et al., 2012; Walsh, 2013; Weides and Majorowicz, 2014; Banks and Harris, 2018; Majorowicz and Grasby, 2021). Commercial development of these basin-hosted geothermal resources has lagged the earlier resource assessments, but several commercial developments are underway. Nonetheless, these resources have not yet attracted large-scale investment, nor has commercially successful geothermal production has been demonstrated.

This paper assesses technical and economic issues that arise from these commercial developments, focusing in particular on risk assessment and economic valuation of the resources. The oil and gas industry has for many years taken a quantitative approach to these assessment of hydrocarbon resources (Rose, 2001), grounded in a petroleum systems analysis. This methodology provides instructive insights that could be applied to basin-hosted geothermal resources for improved risk assessment and valuation. Commercial geothermal developments in the WCSB could provide useful case studies in which to test these methods and concepts.

2. GEOLOGY AND THERMAL STRUCTURE OF THE WESTERN CANADA SEDIMENTARY BASIN (WCSB)

The WCSB is a large foreland basin located between the Rocky Mountains to the west and the Precambrian Canadian Shield to the east. From the Cambrian through Middle Jurassic, the region was a cratonic platform bounded by an ocean to the west (Wright et al., 1994). Sediments deposited on the platform during this time consist largely of carbonates that accumulated on platforms and isolated reefs and basinal mudstones in intervening depocenters, with isolated intervals of sandstone and siltstone deposition notably during the Cambrian and Early Triassic. Block faulting was locally significant. The basin was transformed in the Middle Jurassic (possibly earlier) as exotic terranes accreted to the western margin of the continent and thin-skinned deformation developed, expressed by eastward-directed slip on thrust faults. The eastern limit of contractional deformation is located just east of the topographic Rocky Mountain front in western Alberta and northeastern British Columbia. The change in tectonic regime resulted in a change in depositional style. Deposition became restricted to a broad, north-northwest-oriented trough in front of the deformation belt that was effectively continuous with the Cretaceous Western Interior Seaway in the United States. The dominant lithologies in the Jurassic, Cretaceous and younger sections were almost entirely siliciclastic, consisting of largely sandstones, siltstones, and mudstones.

Geothermal gradients across the basin range average 33.2˚/km but vary considerably (Figure 1; Weides and Majorowicz, 2014). The highest values exceed 50˚C/km, notably in the northwestern Alberta and northeastern British Columbia. Gradients are also elevated in central Alberta, locally exceeding 40˚C/km. In these areas, temperatures in excess of 100˚C can be reached at depths of 2-3 km in parts of the basin. Gradients are lower in the southern and eastern parts of the basin in southern Alberta and southwestern Saskatchewan. Heat flow values are generally consistent with geothermal gradients, exceeding 80 mW/m^2 in northeastern British Columbia, northwestern Alberta and southwestern Northwest Territories. Low values, as low as 30 mW/m^2 occur in southern Alberta and along the eastern margin of the basin south of Fort MacMurray.

The variability in heat flow and geothermal gradient within the basin is complex and not definitively understood at this time. It may in part reflect basal heat flow and thermal contributions from the basement. An investigation by Jones and Majorowicz (1987) concluded that there was no systematic relationship between basement heat production and geothermal gradients, but knowledge of basement structure and composition was then less advanced than at present. Convective heat transfer due to fluid movement in aquifers can in some cases alter the thermal structure of a sedimentary basin. Majorowicz et al. (1999) concluded that water recharge in the Rocky Mountains and eastward flow through aquifers across the basin could decrease temperatures in the west and elevate temperatures in the east but would not be sufficient to explain the observed range or spatial distribution of gradients. In contrast, Bachu and Burwash (1999) considered that aquifer flow would be too limited to have any effect on the thermal structure. Finally, geothermal gradients may reflect the thickness of the sedimentary cover, which influences both the contribution of radiogenic heat from clastic sediments and variation in thermal conductivity as a function of lithology and pore fluid content. These controls have not been directly tested, but the observed substantial variability in geothermal gradient along structural strike could not be explained by this mechanism.

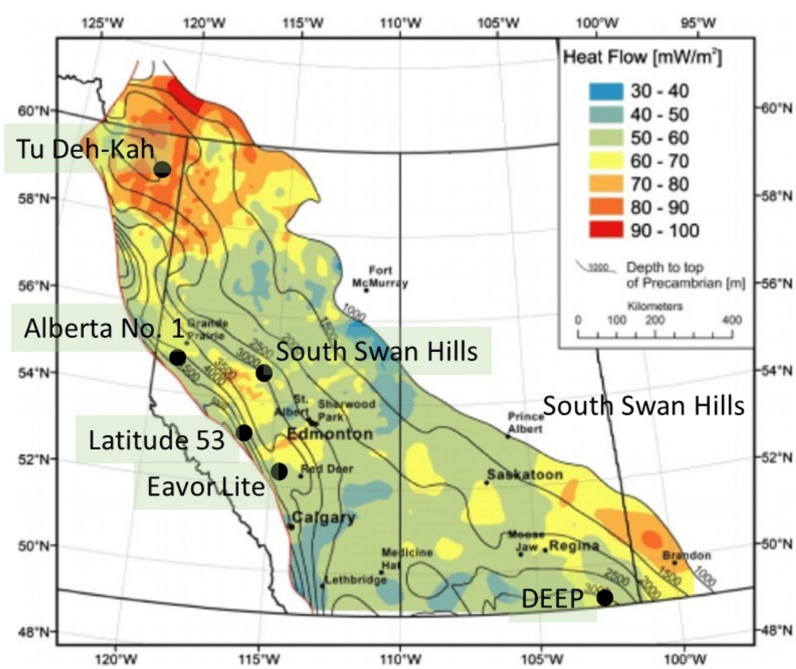

Figure 1: Geothermal gradient map of the Western Canada Sedimentary Basin, modified after Weides and Majorowicz, 2014. Locations of basin-hosted geothermal projects are shown.

3. GEOTHERMAL RESOURCES AND COMMERCIAL DEVELOPMENTS

3.1 Resource Assessments

Geothermal resources in the WCSB have been assessed at different spatial scales and for different purposes. A regional evaluation by Majorowicz and Grasby (2021) assessed the entire basin for both electrical power generation and direct use (primarily district heating). Their analysis concluded that approximately 50% of the basin has suitable reservoirs for district heating (temperatures > 60˚C; flow rates ≥ 30 kg/sec from a producer – injector well doublet. They concluded that much less of the basin was suitable for electrical power generation, stipulating temperatures of >120˚C and flow rates ≥ 80 kg/sec.

A more narrowly focused study (Banks and Harris, 2018) considered the potential for electrical power generation from geothermal resources along the western margin of basin in two carbonate units, the Leduc and Swan Hills formations, and in two sandstones, the Gilwood and Granite Wash formations. Their analysis considered depth and temperature, formation thickness and porosity, and potentiometric head to thermal power and electrical power potential. Estimates for specific electrical power potentials ranged from 0.23 ± 0.12 MWe/km^3 to ~1.6 ± 0.5 MWe/km^3, depending on formation and depth.

3.2 Commercial Developments

Five commercial geothermal projects in the WCSB are now in various stages of development (Table 1). Information represented in the table is derived largely from public information on corporate websites and a few published papers. Four of these projects targets Middle and Upper Devonian carbonate formations in Alberta and British Columbia, while the fifth targets Cambro-Ordovician sandstones in Saskatchewan. All projects have taken advantage of the extensive databases and geologic models developed through decades of oil and gas exploration to diminish risks associated with predictions of temperature and the presence and quality of reservoir formations.

Three projects are relatively advanced, although none of these are yet in commercial production: the Tu Deh-Kah project in northeast British Columbia; the South Swan Hills project in central Alberta; and the DEEP project in southern Saskatchewan. The Tu Deh-Kah project repurposes a now-depleted gas reservoir with an anomalously strong water drive (Walsh, 2013), developed in a dolomitized Slave Point carbonate reservoir (Renaud et al., 2021). Temperatures vary across the field within a range of 110 to 123˚C (Renaud et al., 2021). The field will be developed with producer-injector well doublets and is expected to produce initially 6-7 MW of electrical power. Flow capacity has been demonstrated in an extended flow test. The developer, the Fort Nelson First Nation, is exploring various direct use options for remaining heat in the flow stream. The DEEP project investigates geothermal production from two Cambro-Ordovician sandstones at the northwestern margin of the Williston Basin (Groenewoud and Marcia, 2020). The owner and operator, the DEEP Earth Energy Production Corp, has completed a lengthy flow test and FEED and feasibility assessment for a 32 MW facility (https://deepcorp.ca) but envisions ultimate production of up to 200 MW of electrical power. Finally, the South Swan Hills project will produce 21 MW of electrical power through a natural gas – geothermal hybrid system. This project, operated by Futera Power (subsidiary of Razor Energy Corp., will provide behind-the-fence electrical power for the operation of the South Swan Hills oil and gas field (https://www.futerapower.com/) from a limestone atoll reef in the Middle Devonian Swan Hills Formation (Noyahr et al., in press). The temperature of produced water average 107˚C across the field (Noyahr, 2022).

The remaining commercial projects have been announced but have not tested with respect to geothermal energy production. These are the Latitude 53 project, targeting a Leduc carbonate reef where temperatures are forecast to be 129°C (Banks and Harris, 2018). Novus Earth Energy, the operator, plans a direct use project, utilizing the heat for hydroponics and aquaculture rather than for electrical power generation. The Alberta No. 1 project near Grand Prairie, Alberta, plans to produce 118˚C brine from a Leduc carbonate reef for electrical power generation and district heating.

In addition, Eavor has developed a non-commercial geothermal demonstration project ('Eavor-Lite') near Rocky Mountain House, Alberta, to test the feasibility of a closed-loop geothermal system. This project extracts heat from a moderately low permeability Jurassic sandstone.

4. SCALE AND SOURCES OF INVESTMENT IN BASIN-HOSTED GEOTHERMAL PROJECTS IN CANADA

Most commercial geothermal projects in the WCSB to date have had a substantial investment of government funding (figures are reported from https://researchmoneyinc.com/article/canada-warming-up-to-geothermal-energy-but-still-lags-other-countries). These include: the Tu Deh-Kah project in British Columbia (CAN$40 million from federal government plus provincial funding), Alberta No. 1 in Alberta (CAN$25 million from , and DEEP in Saskatchewan (CAN$27 million from federal government, plus additional funding from private equity and the provincial government), Latitude 53 (CAN$6.6 million). It is likely that none of these projects would have advanced without the substantial government investments.

Two projects have been funded largely through private sources. The South Swan Hills project received CAN$10 million from provincial government sources plus additional funding from the federal government, but the bulk of funding for this $37 million project has been private. The Eavor-Lite project relies largely on private investment of CAN$63 million, although an additional $8.7 million have been provided from federal and provincial sources.

It is notable that no major oil and gas company has invested in a commercial geothermal development in the WCSB, despite their extensive knowledge of the subsurface of the basin.

Table 1: Commercial basin-hosted geothermal projects in the Western Canada Sedimentary Basin.

Project, location	Host formation	Timing and scope	Reservoir temperature	Reference(s)
Tu Deh-Kah, near Fort Nelson, British Columbia	Middle Devonian Slave Point Formation, carbonates	Early development, flow test completed, anticipated 7-15 MW of electrical power plus direct use	110 - 123 ˚C	https://tudehkah.com/ Walsh, 2013; Renaud et al., 2021
Alberta No. 1, Municipal District of Greenview, near Grand Prairie, Alberta	Upper Devonian Leduc	Early development, 10 MW of electrical power plus baseload direct heating	118˚C	https://www.albertano1.ca/
South Swan Hills, near Swan Hills, Alberta	Middle Devonian Swan Hills Formation carbonate	Under construction, gas and geothermal cogeneration, 6 MW of green energy	Average 107˚C	https://www.eralberta.ca/story/provinces-first-co-produced-geothermal-power-project-a-made-in-alberta-solution/ https://www.futerapower.com/ Noyahr et al., in press Noyahr, 2022
Latitude 53 project, near Hinton, Alberta	Upper Devonian Leduc Formation carbonates	Early development, direct use, including hydroponics	129˚C	https://novusearth.ca/latitude53project/ Banks and Harris, 2018
DEEP project, southeast Saskatchewan	Early Paleozoic Winnipeg (Ordovician) and Deadwood (Cambrian and Ordovician) formations, sandstone	Early development of initial 30 MW, test wells drilled and flow test conducted, long term goal of 200 MW	125˚C	https://deepcorp.ca/about/ Groenewoud and Marcia, 2020
Eavor-Lite, near Rocky Mountain House, Alberta	Jurassic Rock Creek Member of Fernie Formation, sandstone	Non-commercial demonstration project of a closed-loop system	78˚C	https://www.eavor.com/eavor-lite/ Vany et al., 2020

5. ISSUES AND OBSTACLES IN THE DEVELOPMENT OF BASIN-HOSTED GEOTHERMAL PROJECTS

The current development of basin-hosted geothermal resources in WCSB (and elsewhere) is limited, with no demonstrated commercial successes and a lack of large-scale commercial investment. The lack of tangible examples of a commercially successful development generally diminishes confidence that these developments are economically viable. Compounding this is a perception that the resource size is small or that development will be expensive relative to other types of resources. If, for example, a well doublet in a 110˚C reservoir produces 1 MW of electrical power, hundreds of wells may be required to achieve the same power production as a coal- or gas-fired power plant.

Nonetheless, these are perceptions and lack economic rigor. More tangible obstacles are:

- No systematic approach to evaluating probability of success (POS) or risk.
- No systematic approach to evaluating resource size.

The lack of systematic approaches to risk analysis and evaluation of prospect size makes it impossible to calculate net present values (NPVs) of unproduced assets and thus to compare value and rate of return of a geothermal project to other potential investments. Until such rigorous comparisons can be made, perceptions will dominate investors assessments of geothermal opportunities.

Methods developed in the mining and oil and gas industries may provide guidance for addressing some of these obstacles. The NPV of an asset in the oil and gas industry is typically calculated as POS * estimated resource value minus development costs if a discovery is made and produced. Estimation of resource value in turn requires predictions of the size of recoverable commodity (petroleum in the case of the oil and gas industry, useable heat in the case of a geothermal asset), the rate at which that commodity can be recovered, and the production costs.

Experience in the WCSB identifies a suite of specific issues related to appraisal of basin-hosted geothermal prospects:

1) The heat content of basin-hosted geothermal prospects over the lifetime of a reservoir. Temperatures within reservoirs may vary by 10-15˚C, important because the efficiency of electrical power generation varies significantly over this temperature range. Temperature models are based on sparse data sets (well measurements, typically from corrected from logging run records) that lack temporal context. Geostatistical and hydrological methods are required to arrive at field-scale assessments of the thermal resource with associated uncertainties in the estimates.
2) The content of dissolved minerals or other commodities (dissolved or entrained gases). Dissolved lithium, boron, helium or other materials of value may be extractable and add commercial value to a project. Geochemical models are based on sparse data sets (well measurements; typically fewer datapoints than for temperature, and datasets lack temporal information). Geostatistical, hydrological and geochemical methods are required to arrive at field-scale assessments of the dissolved mineral resource with associated uncertainties.
3) The behavior of the reservoir during production. Flow rates, water temperature and water chemistry will vary in during the production life of the reservoir, affecting heat recovery and the integrity of subsurface and surface facilities.. Strategies to optimize heat recovery affect well placement, well design and thus production costs. New dynamic models will be required to describe reservoir flow during production that will convolve spatial models of petrophysical properties (static models) with pressure fields and fluid properties (density, viscosity). Static reservoir models are based on sparse data sets from wells, combined with seismic data to define an overall reservoir architecture. Improved models for fluid properties will be required that incorporate the effects of dissolved minerals and entrained gas.
4) Technologies for reservoir surveillance. Tools that monitor reservoir conditions during the lifetime of the field would mitigate risk and increase the long-term economic success of field development and production. Key parameters include petrophysical parameters, water temperature, and water chemistry. New tools may include downhole sensors in wells, in-reservoir sensors such as nanoparticles, and surface installations such as permanently installed geophones.
5) Repurposing existing oil and gas infrastructure. Where oil and gas wells exist (either active or abandoned), repurposing them as geothermal production or injection wells (or monitoring wells) could reduce field development costs. Systematic criteria for evaluating existing infrastructure are lacking and require development.
6) Strategies for assessing value and risk in basin-hosted geothermal prospects. Methodologies for risking resource projects in sedimentary basins are well-developed in the oil and gas industry (Rose 2001). The petroleum systems approach to estimating POS is notable in this regard, but approaches from the oil and gas industry will have to be adapted to apply to basin-hosted geothermal resources. Similarly, probabilistic approaches to characterizing resource size can be adapted from oil and gas reserve assessments.
7) Maximizing benefits to stakeholders. Some geothermal projects in the WCSB are located in small and/or indigenous communities where the economic impact of a commercial development can be substantial. New approaches should be developed to resource development that integrate these stakeholders into development decisions and strategies, aimed at maximizing benefits to these communities and minimizing detrimental effects.

Geology, geochemistry, geophysics, geomechanics and reservoir engineering will be closely linked as these issues in basin-hosted geothermal resources are addressed. Analysis of cool-water plumes around injection wells provides an instructive example. These plumes expand over time and could impinge on production wells. Because the efficiency of electrical power generation is sensitive to temperature, models for the rate of expansion and shape of the cool plumes are critical information for forecasting produced water temperatures and planning well locations. Models by Noyahr (2022) for the South Swan Hills reef show how plumes expand in different sedimentary facies, affected by the geometry of reservoir and non-reservoir rock and petrophysical properties associated with the sedimentary facies found in different parts of the reservoir (Figure 2). Plume shape would also be substantially influenced by the presence of fractures that, depending on orientation relative to the wells, could either focus water flow away from or toward the producing well. Fractures systems in carbonate reservoirs may be enhanced by injection of cool water, because of the retrograde solubility of carbonate minerals.

Geoscience and engineering methods and analyses will be critical to mitigating risk and maximizing value in these systems. Taking the example of cool plumes described in the previous paragraph, sedimentological and petrographic methods will be key to describing reservoir geometries and properties. Geomechanical analysis can predict lithologies that are susceptible to fracture development. Fracture systems can be identified and mapped with multicomponent 3D seismic surveys, and their response to cold water injection can be modeled and predicted with geochemical tools.

Researchers at the University of Alberta are now collaborating with the Fort Nelson First Nation to develop a long-term laboratory at the Tu Deh-Kah geothermal project in northeastern British Columbia to address many of these subjects. The research team will include geoscientists, engineers, social scientists and economists. Members of the Fort Nelson First Nation will be integral participants in all research elements. Studies of the field should commence approximately one year before the field begins commercial production and extend for several years into production.

6. CONCLUSIONS

Basin-hosted geothermal resources in the WCSB are now in commercial development in five relatively small projects, four of which are aimed at electrical power production plus ancillary direct use of heat or CO_2 sequestration. A sixth project is aimed at testing and demonstration of closed-loop production technology. Several of these projects have relied investment and subsidies from provincial and federal governments; private investment in these developments has generally been minimal.

This paper identifies key gaps and risks that are obstacles to the development of basin-hosted geothermal resources. These gaps currently prevent the rigorous assessment of value in these resources and the prediction of rates of return. More specifically, the industry currently lack a systematic approach to estimating probability of success and net resource size. The oil and gas industry has developed rigorous and systematic approaches to address these variables over the past 30 years; these approaches can provide a template for developing similar techniques for basin-hosted geothermal resources.

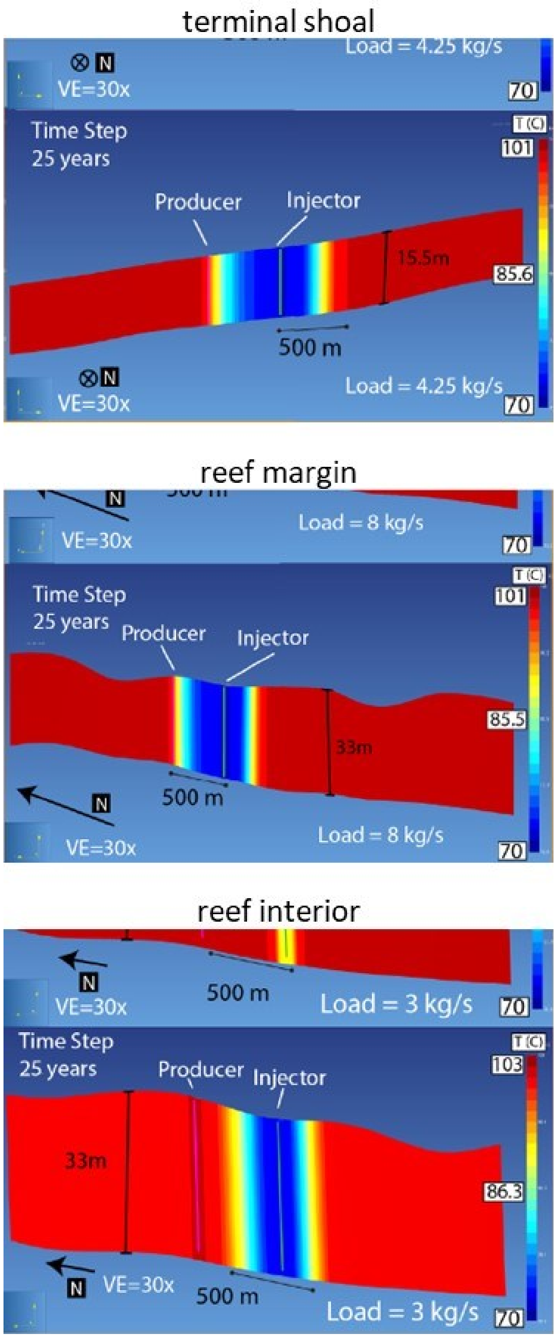

Figure 2: Models of cool-water plume expansion around an injection wells in a producer injector doublet in the South Swan Hills oil field. Modified from Noyahr, 2022.

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