Integrating Geomechanics in SAGD Reservoir Surveillance Programs

by

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ABSTRACT

Reservoir and geomechanical monitoring programs are critical to ensuring operational safety in thermal projects. Although many technologies have been applied to monitor thermal operations, most of them aim to measure just a few parameters, such as pressure, temperature, and surface deformation. While monitoring may aid in understanding phenomena in the subsurface, the data obtained from these observations is significantly divergent from what current models predict. This discrepancy is mainly attributable to the inherent uncertainty in the modeling assumptions and in the input parameters. While reservoir and geomechanical monitoring are not sufficient to inform our understanding of the subsurface's behaviour, they are valuable tools for gaining understanding of the actual behaviour.

Monitoring is a widely used technique in geotechnical projects, where various methodologies and approaches have been proposed to optimize the program's design. These approaches seek to answer fundamental questions such as where to place the instruments, which devices to select, and how the model and the design of the project may be improved through the use of the monitoring results. The present research incorporated knowledge from geotechnical engineering into reservoir engineering to identify an appropriate methodology rooted in engineering principles, which can be followed in thermal operations monitoring planning and deployment. The proposed methodology is logic-based and helps maximize the value of monitoring programs, thereby safely increasing bitumen production in thermal projects.

Coupled geomechanical and flow simulations were performed using a 3D high-resolution geomechanical model to evaluate the response of subsurface to SAGD. Typical monitored parameters were analyzed from different simulation cases to predict monitored results helping design optimal monitoring programs for SAGD. Finally, a case study was used to demonstrate that designing monitoring programs based on prediction results in cost-effective monitoring programs.

DEDICATION

A la memoria de mi padre, Jaime Arias

A mi sobrino, Rafael Rico

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CHAPTER 1 : INTRODUCTION

1.1 Background and Motivation

According to Natural Resources Canada, oil sands deposits represent 97% of Canada's total proven oil reserves (Natural Resources Canada, 2017). Hydrocarbons can be extracted from oil sands using either of two technologies—surface mining and in situ techniques—depending on the depth of the deposit. According to Alberta Energy, mining projects are not profitable when the deposit is more profound than 75 m. Accordingly, only 20% of the total oil sands reserves are considered mineable, while the remaining 80% are buried deeper than 75 m, necessitating the use of in situ techniques.

In situ production involves drilling wells into the reservoir to extract the bitumen, similar to the method of extraction in the case of conventional oil and gas reservoirs. In situ techniques reduce the oil's viscosity by injecting heat or solvents to facilitate flow through the porous formation into the wells. At present, steam injection techniques, such as Steam-assisted Gravity Drainage (SAGD) (Butler et al., 1981) and Cyclic Steam Stimulation (CSS), are the most common in situ techniques in Alberta, Canada. Technical and scientific developments have given rise to the emergence of SAGD as the most widely practiced and efficient method, representing 70% of Alberta's daily production (AER, 2018). In optimum conditions, SAGD can achieve a high recovery factor, up to 80%, along with high production rates, resulting in projects with comparatively higher net present value (NPV) compared to projects deploying other thermal techniques (Guo et al., 2016).

Since the first demonstration of SAGD at the Underground Test Facility in the early-1990s, geomechanics has played a crucial role in the development of this technique (Agar, 1984; Kosar, 1989). Given the shallow depths of reservoirs and the relative lack of consolidation, Canadian oil sands exploitation operations face challenging geomechanical conditions. Such conditions govern the geomechanical response of the reservoirs to changes in pore pressure and temperature and the subsequent interaction with the surrounding formations.

SAGD can be safely applied provided that the containment of reservoir and injected fluid can be ensured throughout the lifetime of the project. To ensure initial reservoir containment, there must be an impermeable layer, often clay, that is thick enough to isolate the reservoir to the upper formations hydraulically. Such a layer is commonly referred to as caprock. The deformations within the reservoir generated by changes in pore pressure and temperature lead to different stress and strain loading conditions in the caprock that can affect its sealing capacity. If the sealing capacity is lost, natural and injected fluids of the reservoir, such as oil, steam, and solvent, find a pathway to the upper layers and subsequently to the ground surface. Such pathways can naturally occur in the subsurface as faults or natural fractures can be generated by the thermal operations from shear and tensile failure or can be a combination of the two.

Inadequate reservoir containment strategies can lead to adverse effects related to caprock integrity, and this has resulted in severe environmental incidents in recent years (Carlson, 2015). Amid the threat of losing the reservoir containment and resource recovery, the interest in understanding the geomechanical issues associated with thermal recovery, on the part of both regulators and industry, has increased significantly in the last decade (Collins et al., 2013). Various processes, it should be noted in this regard, occur in the reservoir under thermal recovery that influence the reservoir's geomechanical response and bounding seals. The main geomechanical processes associated with steam injection are pore pressure increase and temperature increase, causing thermal expansion (Chalaturnyk & Scott, 1995). These changes cause displacement (strain), which in turn leads to stress changes and, in some cases, dilation, shear, and or tensile failure within the reservoir and surrounding formations (Chalaturnyk, 1995). Moreover, these processes may alter the reservoir flow properties, a prospect that must be considered when studying subsurface behaviour (Oldakowski, 1994). For instance, volumetric strain from thermal expansion and changes in stress cause changes in porosity, which in turn affects both the permeability and the saturation of the porous media. As such, flow and geomechanical processes should be analyzed together using coupled reservoir and geomechanical numerical simulation (Settari et al., 1989).

The Alberta Energy Regulator (AER) has taken action to ensure reservoir containment during SAGD operations for shallow projects (AER, 2016). Its regulations consider shear and tensile as the main failure mechanisms of caprock that can result in reservoir containment loss. Tensile failure risk is minimized by ensuring that injection pressure does not exceed the least principal stress value at the base of the caprock to avoid fracture initiation. Shear failure evaluation, on the other hand, usually requires numerical simulation throughout the lifetime of the project to confirm that the caprock has not sheared under operating conditions. Geomechanical/flow simulations and geological models can be very robust depending on the physical features being evaluated and the geological details captured by the model. However, there remains considerable uncertainty in both static and dynamic models, and this, in turn, can lead to inaccurate predictions.

Surveillance or monitoring programs are implemented in most thermal projects to aid in optimizing reservoir performance and managing subsurface risks such as caprock integrity. Instrumentation, such as pressure gauges or thermocouples, is commonly deployed in observation wells to track the growth of steam chambers. Geomechanically-related monitoring, such as ground surface deformation, is typically carried out using interferometric synthetic-aperture radar (InSAR), leveling survey, or tiltmeters. In some cases, the monitoring results are used for calibrating reservoir–geomechanical simulation models. In addition, the regulations governing shallow projects require the inclusion of a monitoring plan that can be used to ensure reservoir containment for projects approvals. Nonetheless, monitoring programs design in thermal projects typically does not follow engineering procedures that maximize the value of information obtained from the instrumentation. In contrast, in geotechnical engineering projects such as dams or slope stability, instrumentation programs are usually designed following engineering procedures in such a manner as to ensure sufficient information to maintain safe operation within a reasonable budget.

1.1.1 Thermal recovery and geomechanics

Thermal recovery is performed by drilling wellbores into the oil sands deposits to inject steam and produce bitumen, where SAGD) is the most used thermal method. It involves drilling two parallel horizontal wells 1 km long at the base of the reservoir, one upper and one lower well. The lower well is drilled at the reservoir's base and is used to drain all the bitumen that settles at the bottom of the reservoir by gravity drainage. The upper well is drilled between 5 and 10 m above the producer and used to continuously inject steam into the reservoir. Injected steam reduces the viscosity of the bitumen to such a point that it can flow by gravity to the lower well, from where it can be pumped up to the surface.

As the process advances, a steam chamber grows in the reservoir, as illustrated in Figure 1-1. Inside the steam chamber, the bitumen that was originally located in the porous space is replaced by steam. The high pressure and high steam temperature inside the chamber induce expansion in the reservoir, resulting in changes to some of the reservoir's petrophysical properties, such as porosity and permeability. Given that petrophysical properties govern the fluid flow within the reservoir, the reservoir deformation also alters the dynamics of the steam injection and, consequently, the bitumen production.

Indeed, several phenomena take place simultaneously in the porous media while the steam injection is occurring, including multiphase flow, water condensation, pore pressure changes, thermal expansion of fluid and solid, petrophysical properties changes, shear failure, and dilation, among others (Li, 2006). Understanding and modelling all these phenomena is a complex task that requires extensive knowledge from various disciplines such as reservoir engineering, transport phenomena, and geomechanics (Settari et al., 1989).

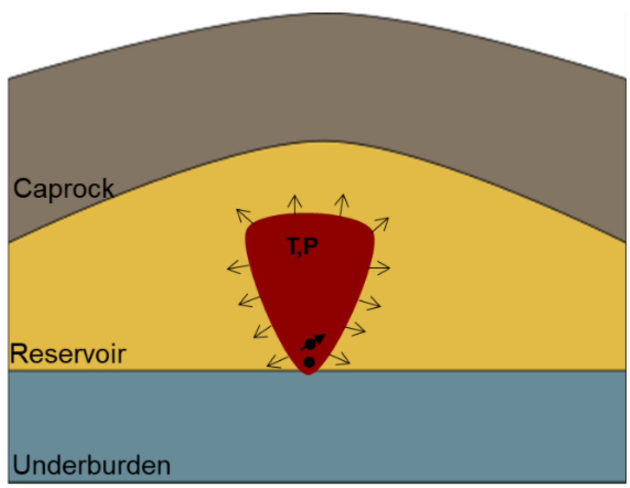


Figure 1-1 Steam chamber and deformation in the reservoir and surrounding formations

1.1.2 Reservoir Containment

SAGD is usually performed on reservoirs of depths less than 500 m, and it has been used in reservoirs as shallow as 80 m. Thus, confining stresses are low and can be easily offset by injection pressures, resulting in negative effective stress and, subsequently, tensile fracture initiation. At certain stress regimes such as normal faulting or strike-slip, the initiated vertical fracture can propagate inside the reservoir to the caprock, leading to loss of containment (Collins et al., 2013). Furthermore, the strains produced in the reservoir during thermal recovery lead to deformations in the caprock that change the load conditions, resulting in shear or tensile failure (Collins et al., 2013), as illustrated in Figure 1-2. Due to the shape of the steam chamber, there is a concentration of shear strength at the flank of the chamber caused by the differential deformation (in turn resulting from the load applied by the chamber in some specific areas of the caprock). On the other hand, at the top of the well-pair, horizontal stresses at the caprock are reduced by the arching deformation that has been caused by the reservoir expansion, thereby reducing the effective stress. This region thereby becomes more prone to tensile failure initiation (Xiong & Chalaturnyk, 2015).

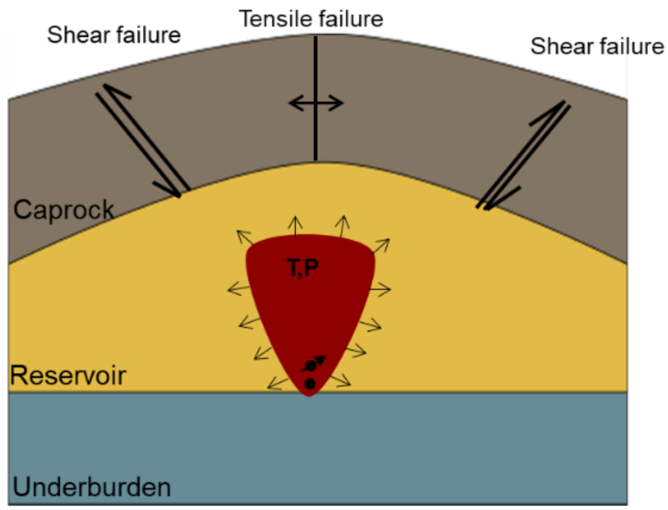


Figure 1-2 Schematic of possible failure mechanisms in the caprock during SAGD

In oil trap systems, caprock is an impermeable layer at the top of the reservoir that facilitates the accumulation of oil in the porous and permeable reservoir. During steam injection, it also plays a vital role in acting as a seal that hydraulically isolates the reservoir to the upper layers and ground surface. When the caprock is breached, steam, water, bitumen, and solvent could flow from the reservoir to the upper layers, leading to severe environmental and economic issues. Various mechanisms, such as shear and tensile failure and the interaction with natural discontinuities commonly found in the caprock shale, can create flow pathways in the caprock (Carlson, 2011; Heikal, 2020). Moreover, wellbore integrity issues such as casing failure and cement quality issues can contribute to pathway generation, where flow is allowed to the upper layers as illustrated in Figure 1-3.

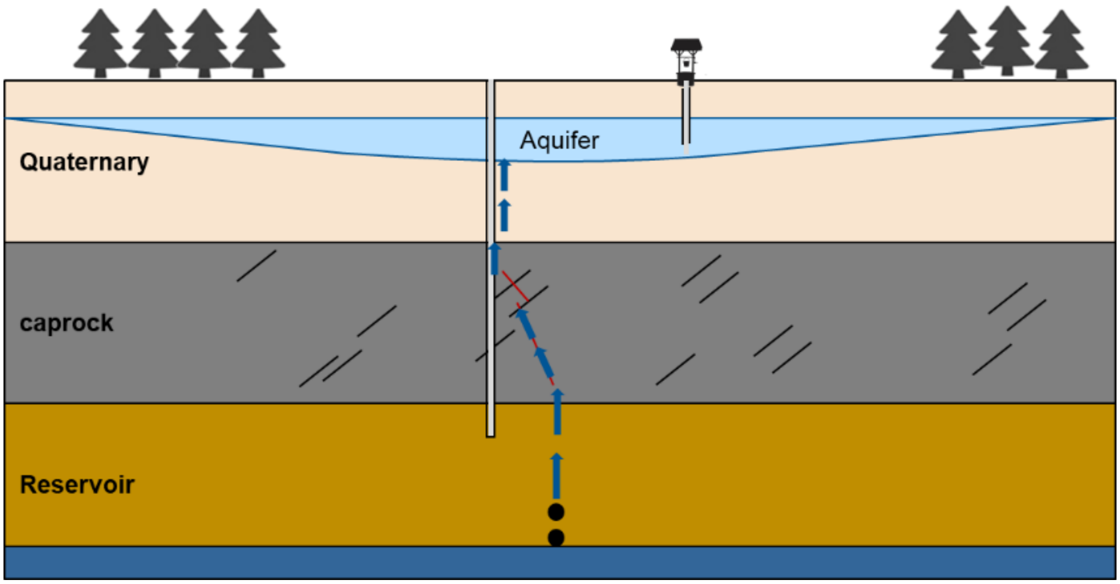


Figure 1-3 Different pathways that can be generated or opened during steam injection, allowing flow from the reservoir to the upper layers.

1.1.3 Regulation

In the wake of some notable incidents at in situ thermal recovery projects, the AER issued a directive to regulate SAGD operations in shallow areas (AER, 2016). AER has defined Shallow Athabasca Oil Sands Areas; it should be noted, as regions where the base of the caprock is shallower than 150 m. Caprock, in turn, is defined as low permeability and geomechanically strong strata that can effectively contain reservoir fluids. The caprock should meet three criteria:

- be a minimum of 10 m thick,
- be composed of clay-rich bedrock, with a gamma-ray value greater than 75 API units, and
- be laterally continuous across the project area.

The directive also includes a formula to calculate the maximum operating pressure (MOP) of the project. The MOP is calculated by multiplying the fracture pressure at the base of the caprock by a factor of 1.25. Additionally, geomechanical modelling must be conducted to address potential shear failure at the caprock. Finally, a corresponding monitoring program to confirm that the operations are maintained within these parameters must be included in the project application.

Although there is no directive as explicit as Directive 86 for SAGD performed in reservoirs deeper than 150 m, reservoir containment risk should be evaluated for every application. For reservoirs below this depth threshold, the information required, and corresponding analyses are determined on a case-by-case basis. Nevertheless, numerical simulation and a robust monitoring program are often required to confirm the safety of the operations.

1.2 Problem Statement

Maintaining in situ operating conditions at safe injection pressures is critical for safe, sustainable, and economical oil recovery. Due to inherent uncertainty in modelling and knowledge of subsurface behaviour, SAGD projects may fail to adequately account for subsurface physics as reflected in their operational conditions, rendering them overly conservative or risky. Indeed, the injection pressure significantly affects the recovery factor, and, accordingly, the cost-effectiveness, of projects. Not only that, but the regulator usually requires reservoir monitoring, such as monitoring of temperature and pressure in observation wells and surface heave, to verify that the project is operating under safe conditions.

Although reservoir monitoring programs are an integral component of thermal projects, the design and implementation of these programs have not been thoroughly researched. Monitoring is an essential tool that should be included in the decision-making analysis of the project and evaluating the value of information from the monitoring reinforces the importance of having an appropriate monitoring plan in the project. However, public reports and scientific articles on the subject do not include information about how monitoring design should be planned in thermal projects.

Several questions should be addressed when designing an appropriate monitoring program. This includes what parameters will be measured, what type of instrumentation should be installed, where it should be installed, and at what frequency data should be recorded. It should also include a clear plan for data collection and further use or analysis of the data. Although geomechanical aspects must be predicted in order to address most of these questions, monitoring planning is also typically subject to various non-technical considerations, such as the availability of delineation wells in the area or an arbitrary number of wells per drainage area neglecting the geological settings. As a result, reservoir monitoring, though costly, often ends up adding little benefit to the operations. Having a preliminary engineering analysis prior to installing a monitoring program is a crucial step that should be included to ensure a cost-effective surveillance strategy.

1.3 Research Objectives:

In this context, this research aims to improve our understanding of the planning and utilization of reservoir–geomechanical monitoring implemented in thermal operations. This objective is achieved through detailed coupled reservoir–geomechanical simulations to identify the response of sensors at different locations of a heterogeneous model representing a SAGD project's virtual environment. In addition, a case study analysis is included to evaluate the effectiveness of the program deployed in the field and to compare it to the methodology proposed in this research. The specific research objectives of this Ph.D. dissertation are as follows:

- To review the available literature regarding monitoring planning in geotechnical engineering and apply it to SAGD projects. This work will include the identification of the particularities and specific conditions of SAGD that differ from typical geotechnical projects. The review of monitoring planning and the identification of particular problems for SAGD monitoring will lead to developing an approach that takes into account engineering analysis to design monitoring programs in SAGD projects.
- To study the influence of heterogeneity on the response of monitored parameters in a SAGD project. This objective will require building a high-resolution geomechanical model that includes as many geological features and heterogeneity of the subsurface as possible using public data. The geocellular model construction will require review of laboratory testing for the different related strata of the area, a compilation of different sources of information such as well logging, minifrac, and horizon markers.
- To identify optimal monitoring locations based on numerical simulation. This work requires conducting 3D geomechanical coupled simulations to evaluate the subsurface's response to SAGD in a virtual environment. The simulations will include

sensitivity analysis of flow and geomechanical properties, 2D and 3D simulation, and operating conditions that will cover the different monitoring scenarios. The sensitivities will also help study the effect of heterogeneity on monitoring results.

- To verify surveillance design through a case study. This objective will include the analysis of monitoring results from Joslyn Creek's post-failure operations. This objective will also include identifying the aspects of monitoring design that can be improved using the findings from the previous objectives of this research.

1.4 Methodology

The first step is to develop a methodology for planning monitoring programs for SAGD based on methods and knowledge commonly used in geotechnical engineering applications such as slope stability and dams.

A high-resolution geological model is built to be used in the coupled simulation. The model seeks to capture as many geological features of the area as possible for the purpose of evaluating the geomechanics in consideration of geological heterogeneities. Considering that many available monitoring techniques measure the ground surface heave, the model needs to include all the strata from the ground surface to the underlying formation of the reservoir. The high-resolution model also allows the integration of heterogeneities and anisotropies typical of sedimentary formations of the Athabasca area (McLennan & Deutsch, 2005). The geological model is generated using various data sources such as geophysical well logs, core analysis, and the results of geomechanical laboratory tests. The data measured in well logs and core analysis, it should be noted, typically relates to petrophysical properties such as porosity, permeability, and saturation and is used to populate the grid within the reservoir (flow model). Logs such as gamma-ray and photoelectric factor also assist in the identification of various lithologies, such as sand and clay, that help to define the geomechanical facies for the formations under study.

The high-resolution model is then adopted as a "true" model of a SAGD case and is used to evaluate the responses of various monitoring variables such as temperature, pore pressure, and deformation under different operating conditions. The results are analyzed and compared to a homogeneous model to identify the effect of geological heterogeneity (typically characteristic of sedimentary rocks) on the monitored variables. The results are analyzed to obtain a monitoring design that appropriately characterizes the subsurface behaviour, leading to better decisions to ensure the safety of the operations.

Finally, the monitoring results from a case study are analyzed to evaluate the difference between technologies and the factors that affect measurements. An analysis of the value of information is performed to identify the location where measurements will maximize the value obtained from monitoring devices. Ultimately, the monitoring results are compared to numerical modelling to demonstrate the importance of following engineering criteria for a cost-effective monitoring design.

1.5 Thesis Outline

This thesis contains 8 chapters where the research work carried out to achieve the objectives, and the results obtained, are described.

The introductory chapter is followed by:

CHAPTER 2: REVIEW OF RESERVOIR CONTAINMENT AND MONITORING IN SAGD

This chapter describes the geology of the Athabasca area, reviewing previous incidents and identifying the main mechanisms that led to caprock failure. It also includes a review and analysis of the various techniques and instruments commonly used in thermal projects, such as thermocouples, piezometers, and surface deformation. The analysis includes an overview of the challenges and benefits of each of these techniques and devices in the context of reservoir performance and operational safety.

CHAPTER 3: PLANNING MONITORING PROGRAMS FOR STEAM ASSISTED GRAVITY DRAINAGE (SAGD

This chapter describes the development of a workflow for reservoir monitoring planning for SAGD, based on a widely used methodology in geotechnical engineering proposed by Dunnicliff in 1988. The workflow includes all the steps to be followed to attain optimal monitoring design planning based on engineering criteria. The workflow assists in addressing questions such as what kind of instruments should be used, how many, where they should be placed, and at what frequency data should be recorded, among others.

CHAPTER 4: HIGH-RESOLUTION MODEL FOR THERMAL FLOW GEOMECHANICS SIMULATION

This chapter outlines the procedure for generating the static model used in the thermal-flow-geomechanics simulation to evaluate the response of monitoring variables. The chapter also includes an analysis of the geology in the area based on well logs to identify heterogeneities within the reservoir and caprock. The model captures heterogeneities in flow properties such as porosity, permeability, and saturation in the reservoir. Also, different geomechanical facies such as sand, silt, and clay are identified within the reservoir and caprock to capture the heterogeneous behaviour of sedimentary rocks. The static model is assumed to be a "true" model representing the actual geological conditions of a SAGD case.

CHAPTER 5: PREDICTION OF MONITORING PARAMETERS FOR SAGD

This chapter presents the results of various monitoring targets such as pore pressure, temperature, and displacement, given the heterogeneity previously adopted. An analysis of the implication of the measurements on the safety of the operations is also provided. Various scenarios are studied, such as the use of high-pressure and homogeneous models, in order to compare them to the "true" model built in the previous chapter. The differences in variables commonly monitored are analyzed to the effectiveness of the monitoring in capturing what is actually occurring in the subsurface. Analysis of the subsurface response to SAGD, such as steam chamber growth in the reservoir and stress path at different locations within the caprock, is also evaluated to gain understanding of the mechanisms underlying failure. These analyses are the primary inputs in the design of a cost-effective monitoring program that can be used to ensure reservoir safety.

CHAPTER 6: SELECTING INSTRUMENT LOCATIONS FROM GEOLOGICAL INFORMATION

One of the main challenges when designing monitoring programs is placement of the instrumentation. Critical locations that maximize the value of information should be carefully selected to ensure the cost-effectiveness of the monitoring program. In this chapter, a simple approach to identifying the optimal locations is proposed. The methodology is based just on geological data and can be implemented using only the static geomodel, without the need for complex simulations. Also, the project risks associated with early time (start of operation) and late time (fully growth steam chamber) are analyzed to better understand the risks through the project lifetime.

CHAPTER 7: CASE STUDY- JOSLYN POST FAILURE **MONITORING**

This chapter includes a complete analysis of Joslyn's monitoring data acquired after the steam release incident, validating the monitoring planning proposed in this research as a means of achieving a cost-effective geomechanical monitoring program that captures relevant phenomena and mitigates risk. The instruments and measurements obtained from this program are analyzed and compared to the methodology proposed in the previous chapter as well as to simulation results.

CHAPTER 8: CONCLUSIONS AND RECOMMENDATIONS

This chapter summarizes the main conclusions and findings of this research. It also provides recommendations for future work on the topic.

CHAPTER 2 REVIEW OF RESERVOIR CONTAINMENT AND MONITORING IN SAGD

2.1 Alberta oil sands geology

Oil sand is a naturally occurring mixture of minerals such as sand, clay, silt, water, and bitumen. Bitumen is also known as heavy oil due to its extremely high viscosity and density, resulting from the large hydrocarbon molecules that compose it. Alberta has three major oil sands deposits: Peace River, Cold Lake, and Athabasca, Athabasca being one of the world's largest deposits. Athabasca deposit is shallow enough at some locations that bitumen can be extracted by surface mining techniques, as illustrated in the light orange region presented in Figure 2-1. Nevertheless, if the deposit lies deeper than 75 m, in situ techniques are required to extract the resource (see Figure 2-2). The Peace River and Cold Lake deposits are deeper than 75 m; as such, mining techniques are not practical, necessitating in-situ techniques to extract the bitumen. In total, there are 165 billion barrels of bitumen in the Alberta oil sands that are available for extraction using existing technologies. An additional 150 billion barrels, meanwhile, could be recovered with the introduction of innovative extraction technology coupled with favourable oil prices.

At the Athabasca deposit, the main layer saturated with bitumen is the McMurray formation. McMurray is a fluvial–estuarine channel point bar deposit that was deposited during the Lower Cretaceous. McMurray thickness can vary from 0 m to 110 m depending on the site (Hein, 2015). The lower part of McMurray formation was sedimented in a point bar environment, which makes the reservoir quality particularly high in this region of the formation due to its good grain selection—mainly quartz grains of coarse to medium sand size.

The upper part of the formation, meanwhile, was deposited in a transitional environment subject to the effect of tides, resulting in embedded layers of clay and sand of a poor grain selection, a phenomenon known as Inclined Heterolithic Stratification (I). Although this portion of the formation may contain some bitumen, more effort is required for its extraction due to its low vertical permeability. Above the McMurray formation lies the Clearwater formation, a marine sequence that is divided into different members. The oldest member of the Clearwater formation, Wabiskaw, exhibits considerably variable mineralogy and thickness in the area; even within the same location, the grain size can change significantly. The sandy and silty layers of Wabiskaw are commonly used as the first monitoring layer to identify early flow upwards by measuring pressure and temperature in these layers.

The other Clearwater formation members are mainly marine sequences that can be classified as clay with some non-continuous silt and sand interbedded. The lower members of the formation have been classified as Clearwater argillaceous due to the high presence of clay minerals (Huag et al., 2014). According to the AER, they have been identified as non-permeable zones that can act as an effective caprock for steam injection (AER, 2016). Finally, the overburden of the area is a glacier deposit that was deposited in the Quaternary period.

Cretaceous sediments overlay a sedimentary succession of carbonate sediment from the Devonian period unconformably. It comprises a lithologically diverse sequence of carbonates, evaporites, and clastics (Cotterill & Hamilton, 1995). Due to the age of the rock, it is well lithified and competent, having been characterized as a stiff and strong material (Chalaturnyk, 1995). An overview of the stratigraphic column is shown in Figure 2-3.

2.2 Previous reservoir containment loss incidents

Most of the efforts around thermal recovery technology have been undertaken in Canada. Along with the advancements made, there have been some adverse effects caused by reservoir containment loss (Carlson, 2015). Understanding what happened in these instances and identifying the processes that led to them is crucial to planning an effective monitoring design capable of anticipating such incidents. This section presents a brief review of the most notable incidents of reservoir containment loss, the failure process, and the underlying causes.

Note: 1 km^2 = 1 square kilometre = 0.39 square miles

Figure 2-1 Oil sands deposits in Alberta—originally published in (aer.ca).

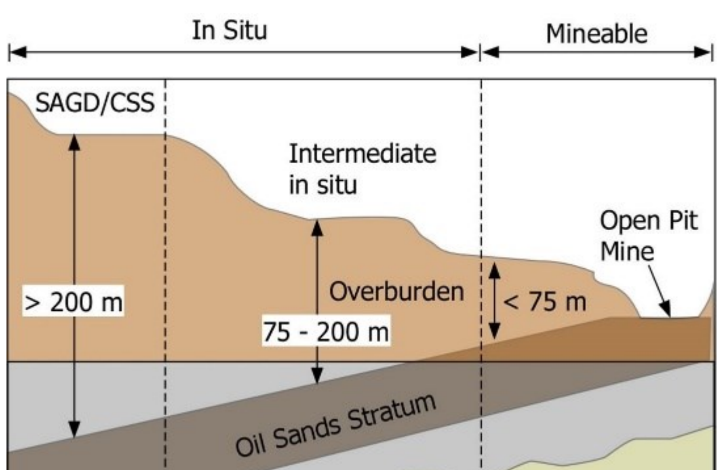


Figure 2-2 Schematic cross-section of Northeast Alberta sedimentary basin—originally published in (awrl.ca)

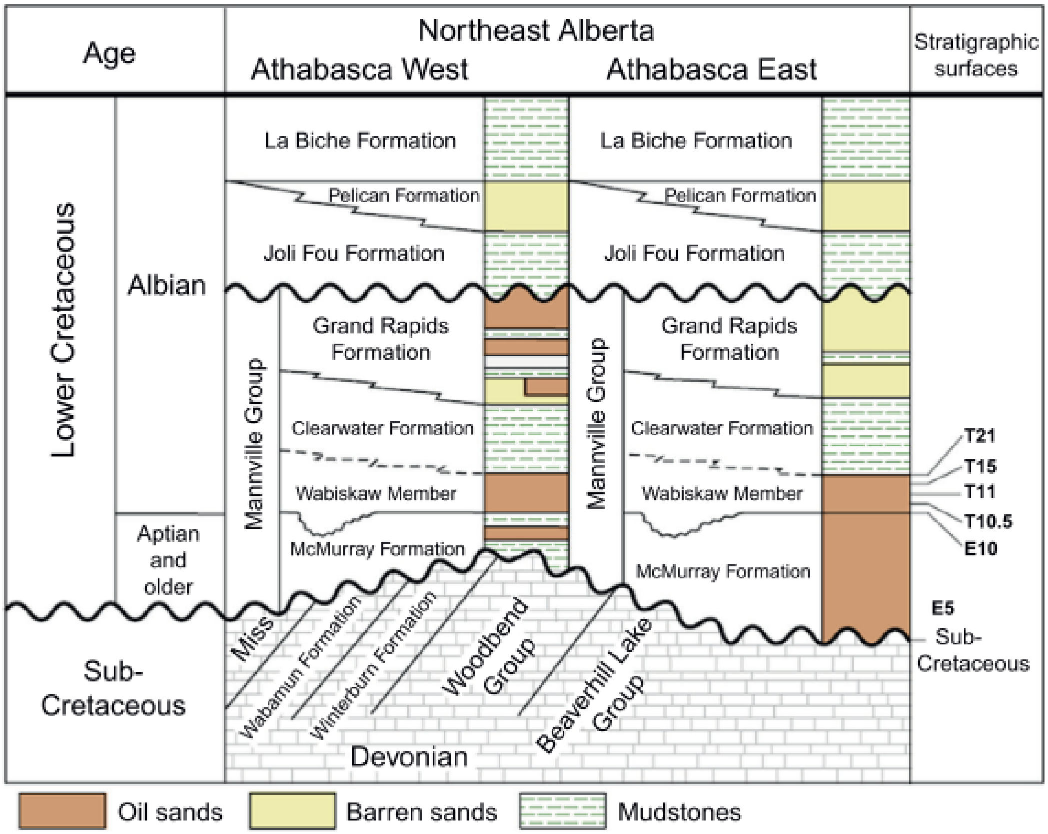


Figure 2-3 Stratigraphy of Northeast Alberta—originally published in Hein (2015)

2.2.1 Texaco Fort McMurray Airport, 1979

Texaco started a pilot project injecting steam to recover McMurray formation bitumen in the vicinity of the Fort McMurray International Airport (Figure 2-4). In this project, steam flooding was evaluated using two different recovery patterns with vertical wells. On June 11, 1979, four years after Pattern I operations had commenced, there was a steam blowout near Pattern I.

Due to the incident having occurred several decades ago, information about the blowout is limited, although a presentation by Livesey (2013) describes the flow pathway that was generated by the steam injection. Figure 2-4a shows the horizontal projection of the pathway (dotted line), while Figure 2-4b shows a cross-section, including the strata related. According to Livesey, the pathway started with a casing break at poi“t”"A" that communicated the reservoir to a gravel zone. An initial blowout took place at poi“t”"C" with a plume up to 200 ft. After this blowout stopped, a second blowout occurred at poi“t”"B" that lasted approximately two days. There was no oil spill reported in the incident, and the injection pressure subsequently decreased in both patterns.

The project was located in the shallow SAGD area as defined by AER (2016). The depth of the reservoir is around 75 m, and the injection pressure of the project was 2,000 kPa, resulting in a pressure gradient of 26.67 kPa/m, significantly higher than the minimum stress of the caprock in the area (21 kPa/m) reported by Bell (Bell & Grasby, 2012a). After the incident, operations continued for six more years. In 1980 the project evaluated horizontal wells via steam injection, and in 1986 the project was terminated.

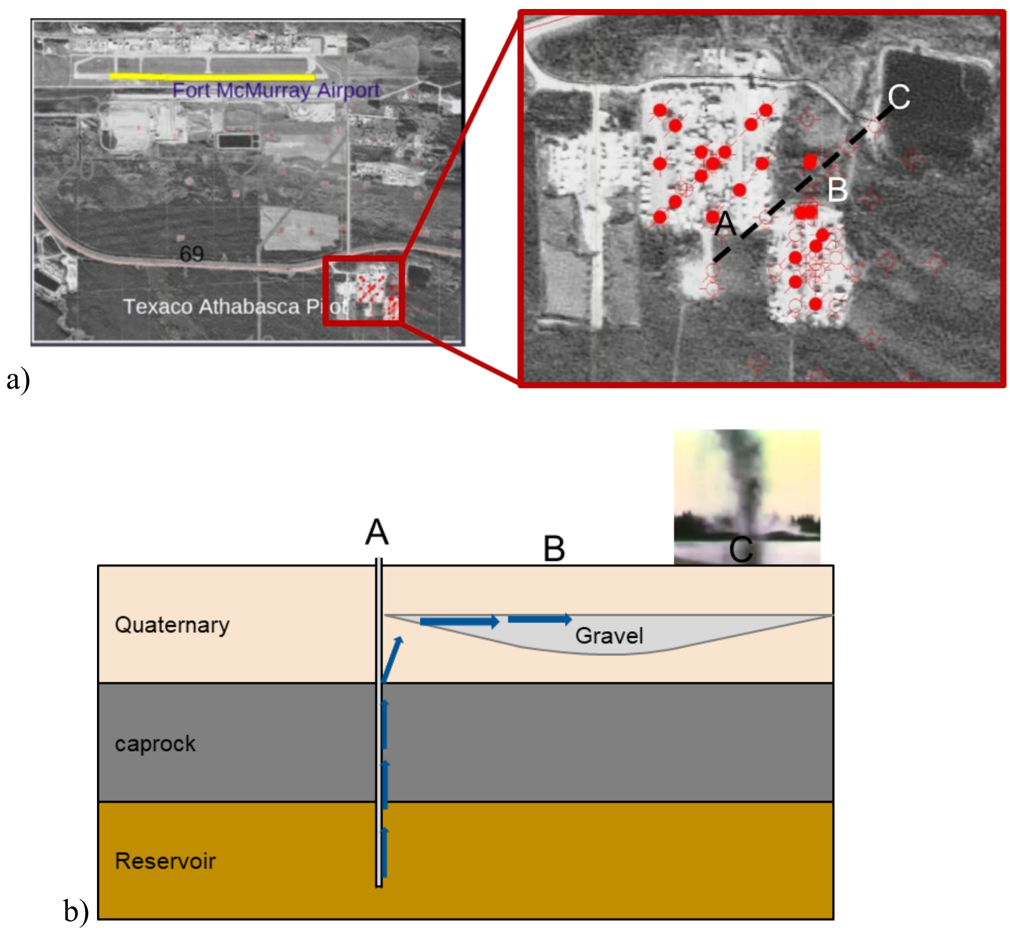


Figure 2-4 Blowout Texaco Fort McMurray Airport **(a)** aerial photographs of the patterns—originally published in Livesey (2013) **(b)** Cross-section scheme of the project and flow pathway.

2.2.2 Joslyn 2006

Joslyn Creek was a SAGD project operated initially by Deer Creek Energy in 2004 and by the French company, Total Energy in 2006 when it acquired Deer Creek Energy. It started with a pilot well-pair in 2004 designated as Phase 1. Phase 2 began in December 2005 and corresponded to the commercial development of the project. It was designed to produce 10,000 bbl/day from 17 well-pairs. A blowout at Well-pair 1 in Pad 204 occurred on the morning of May 18, 2006, just a few days after production had begun. The release created a crater 75 m wide by 125 m long (Figure 2-5a) and caused rock ejections that spread over a distance of 300 m, causing some minor damage to pipelines. At the time of the incident, the well-pair was just starting the production phase following a lengthy circulation and semi SAGD phase.

In exploring for the release's root causes, there were some discrepancies between the reports of Total Energy's staff and those of the Energy Resources Conservation Board (ERCB), as presented in its official report (Energy Resources Conservation Board, 2010). More recently, researchers at the University of Alberta have conducted detailed analyses based on field performance data to investigate the incident (Khani, 2022), considering both the reports of the operator and the regulator and consulting additional data and evidence to identify the root cause and processes that precipitated the steam release. A pathway from the pilot Well-pair located approximately 500 m from the crater was identified using monitoring data and leading-edge numerical simulation tools (Khani, 2022). This pathway allowed the accumulation of steam at the top of Well-pair 1, as revealed by the seismic analysis (Figure 2-5b). An abnormal change in injectivity on April 12, 2006, during semi-SAGD on Well-pair 1, was observed, suggesting a hydraulic fracture initiation in the reservoir. Due to the region's stress regime within the reservoir formation, the induced hydraulic fracture is likely to be vertical; as such it would have connected Well-pair 1 to the steam accumulation at the top, as shown in Figure 2-5b.

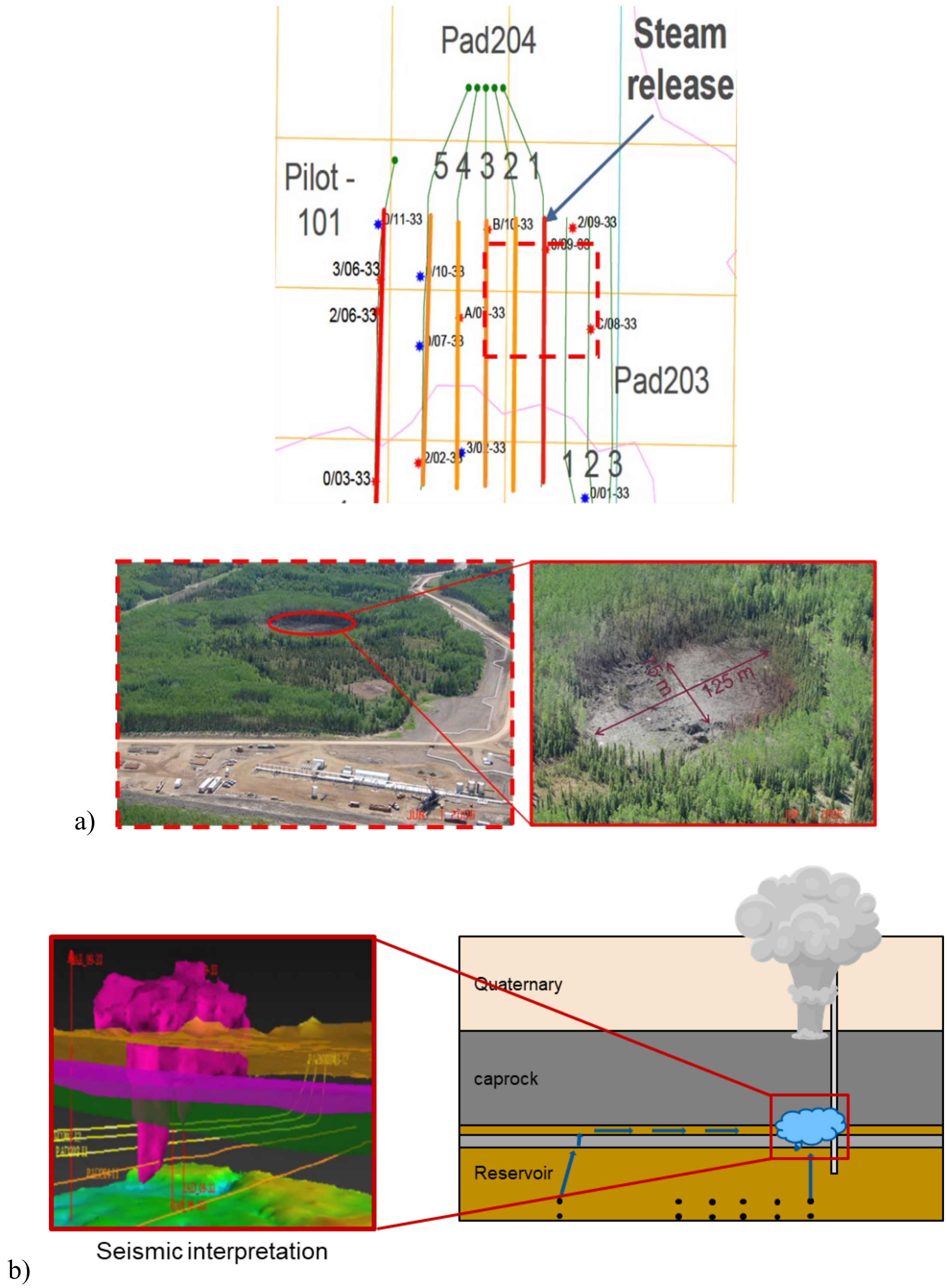


Figure 2-5 Joslyn Blowout. (a) Pad 204 map and crater generated during steam release—originally published in Energy Resources Conservation Board (2010). (b) Seismic and schematic cross section of subsurface chimney.

On May 11, 2006, Well-pair 1 started the SAGD stage, where injection pressure was incrementally increased. Over this period, the bottom-hole pressure (BHP) increased at the injector well up to 1,800 kPa until May 18, when the steam release took place. Given the depth of the caprock at the location (70 m), the pressure gradient used was about 28 kPa/m, which is significantly higher than the gradient of vertical stress of 21 kPa/m reported in the area (Bell & Grasby, 2012a).

The project was shut down for some months, then restarted operations at the beginning of 2007 with a new operating pressure of 1,200 kPa. After 20 months of production, the project was permanently suspended since it was no longer economically viable at the new operating conditions (injection pressure).

2.2.3 Primrose 2009/2013

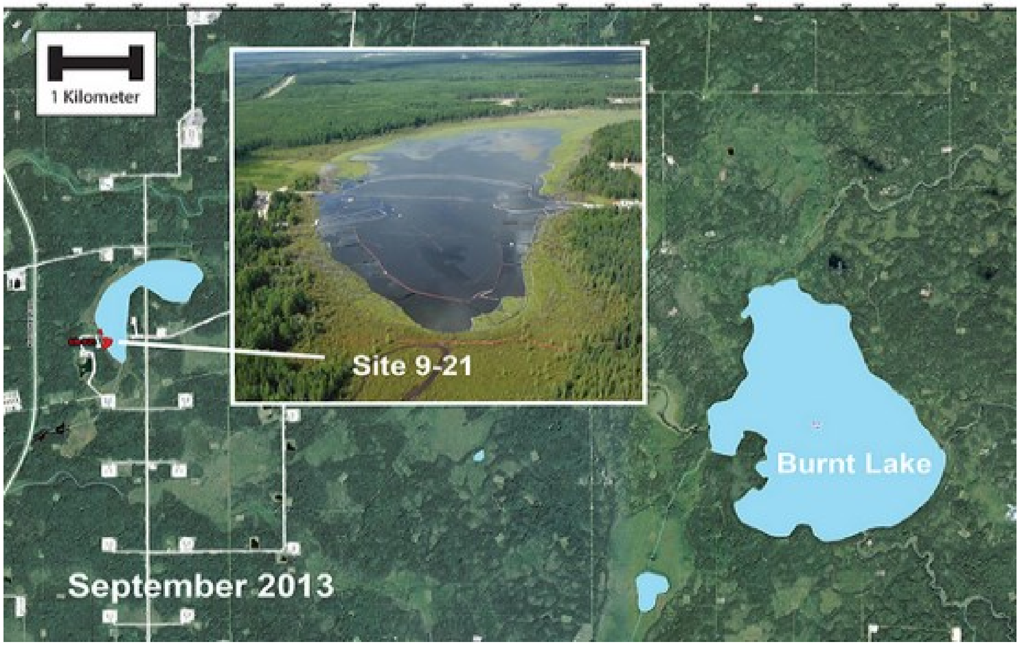
In 2013, bitumen emulsion was discovered on the surface at four locations in CNRL's Primrose Project, causing environmental issues and contaminating some bodies of water, as shown in Figure 2-6. Besides the four locations reported in 2013, there had been a previous flow-to-surface (FTS) event in 2009 in the same project (Canadian Natural Resources Ltd., 2013). The project, which continues to operate, is located in the Cold Lake deposit and involves Cyclic Steam Stimulation (CSS) operations, the reservoir being at an average depth of approximately 500 m. After the discovery of the FTS in 2013, an exhaustive study was undertaken to identify the root causes of the events. The investigation resulted in the drilling of 138 new vertical wells and the study of 106 existing cased wellbores in the area. Following completion of the study, a final report was prepared to address the mechanics that generated the pathway from the reservoir to the surface (Alberta Energy Regulator, 2016). In the report, four different conditions that enable the generation of the flow pathway were identified. These four conditions were found at most of the FTS locations: (1) excessive flow of bitumen emulsion from the reservoir to the subsequent overlying permeable formation, (2) a vertical hydraulic fracture that breaches the Grand Rapids formation (tight formation), (3) cement quality issues in the wellbores that facilitate vertical flow into the caprock where the stress regime favors horizontal fractures, and (4) alteration of the stress state in the caprock caused by expansion from CSS operations, in turn opening low-angle fractures that act as pathways through which for the emulsion reaches the upper permeable formations (see Figure 2-6b).

The CSS operations at Primrose involve the use of high injection rates to enhance the injectivity and productivity of the reservoir and thereby increase the project's recovery factor. High-pressure CSS facilitated the generation of the conditions previously explained. As mentioned, the Primrose Project is still operating as of the time of writing, and, subsequent to the incidents mentioned above, the injectivity rates and associated BHP have been managed in such a manner as to maintain safe operation of the project.

2.3 Reservoir Monitoring

Surveillance has been used in the oil and gas industry since the early days of reservoir management as well as different applications in production engineering. Kunkel & Bagley (1965) presented an application of reservoir monitoring to achieve the goals of maximum oil recovery during water flooding. In the following decades, with the introduction of Enhanced Oil Recovery (EOR) pilots and advancements in computing technologies, reservoir monitoring emerged as a useful technique for evaluating the efficiency of EOR projects (Bucaram & Sullivan, 1972; Moore, 1986; Talash, 1988).

At that time, the primary objective of monitoring was to gather data, whereas the documentation, integration, and automation of systems did not appear until later. As more sensors became available in the oil and gas sector, accompanied by the significant advances in computation equipment in the 1990s, reservoir surveillance became crucial in reservoir management. At this point, monitoring was used not only to gather data, but also to interpret it and use it to plan better reservoir management strategies (Raza, 1992; Satter, 1990; Satter et al., 1994). More recently, reservoir monitoring has become a powerful reservoir management tool, and monitoring workflows, rather than being limited to data acquisition, are also widely used in decision support applications such as modelling and forecasting. The concept of the "smart field", where monitoring results are interpreted instantaneously by automating operating variables such as bottom-hole pressure and rate to improve reservoir performance, has also emerged in recent decades as a popular application of reservoir monitoring (Glandt, 2005; Mohaghegh, 2009; Portella et al., 2003; Scott et al., 1994).

a) 

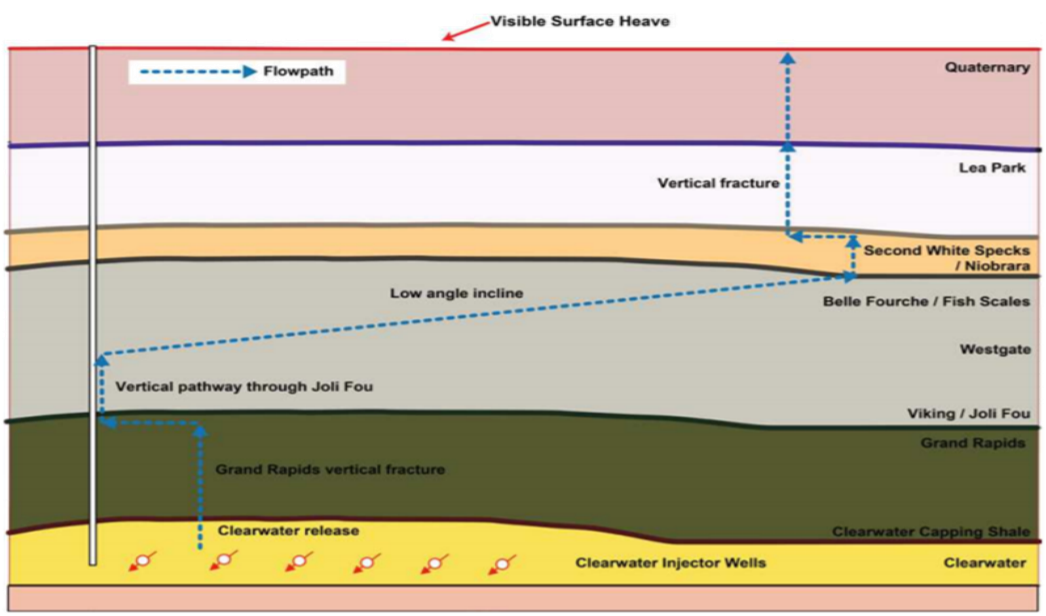
b) 

Figure 2-6 Primrose emulsion release. (a) Map showing contamination in water bodies at the surface. (b) Schematic of the FTS pathway with the four enabling conditions, originally published in AER (2016).

Finally, recent advances in computing science such as machine learning and data analytics have enabled the efficient handling, visualization, and analysis of extensive data arrays to optimize recovery and investment by enabling sound and expeditious decision-making based on real-time data. As these examples underscore, reservoir surveillance has become a crucial tool in reservoir management and uncertainty reduction (Chen et al., 2017; Djuraev et al., 2017; Jeong et al., 2018; Lochmann, 2012; Moghadam et al., 2011; Mohaghegh, 2009).

2.4 Monitoring in CO_2 storage

Caprock integrity is not only a concern in the context of thermal recovery in oil sands, but is a key consideration for any process that involves fluid injection to the subsurface (Schultz et al., 2014). Such is the case in geological CO_2 sequestration, where CO_2 is stored in porous formations to reduce greenhouse gas emissions to the atmosphere. Risk management is generally used to minimize and mitigate risk related to subsurface containment in CO_2 sequestration projects, and each case is evaluated for long periods of time since containment relies on geomechanical behaviour over thousands of years (Paluszny et al., 2020).

Containment loss risk in CO_2 storage has garnered increasing interest in recent years, and monitoring is playing a key role in reservoir containment assurance in this context. CO_2 can be stored in the deep ocean or injected into reactive rock formations, depleted hydrocarbon reservoirs, and saline aquifers (Bickle, 2009). Due to the considerable depth below the ground surface of such projects, in-situ and air instrumentation are the main approaches used in CO_2 storage. Commonly monitored parameters in CO_2 storage projects are chemical composition of air, well annulus pressure, pressure and temperature in the injector wells, reservoir pressure and temperature, and groundwater and surface water quality (Boreham et al., 2011; Jenkins et al., 2012; Lescanne et al., 2011). Downhole microseismic monitoring has also been used to capture caprock failure in projects of this nature. For instance, Zambrano-Narvaez (2012) presented a monitoring design that employed surface tiltmeters to evaluate caprock integrity during CO_2 injection. However, they concluded that tiltmeter measurements are affected by external conditions such as weather changes, and that the results are not entirely representative of the subsurface behaviour.

Other studies have been conducted to optimize the performance of different monitoring techniques, most of them aiming to calculate and quantify the project's geological uncertainty (Cameron, 2013; Seto & McRae, 2010). For instance, Cameron (2013) proposed an approach to optimize instrumentation location under two different scenarios of geological uncertainty. This work also developed a closed-loop for well operation optimization based on monitoring data.

Although reservoir containment for CO_2 storage represents a similar risk to thermal recovery in oil sands projects, the depth below the surface is a key factor in reservoir containment. Oil sands are subjected to lower stress states (compared to CO_2 storage projects) that can be easily overcome. Furthermore, the soil-like behaviour of oil sands strata plays a key role in the geomechanical response as it pertains to monitoring design.

2.5 SAGD monitoring

Since the initial evaluation of SAGD in the late 1980s, at the SAGD pilot stage, monitoring has been a crucial tool for understanding the process. At the beginning of the 1980s, Alberta's government funded a project called the Underground Test Facility (UTF) to demonstrate the feasibility of using Steam Assisted Gravity Drainage (SAGD) to recover bitumen at a depth beyond that which conventional surface mining methods were productive. The UTF phase A, located 60 km north of Fort McMurray, opened in 1987 and included two vertical shafts that descended over 200 m deep to transport personnel, house equipment and ventilate the chambers. For the UTF Phase A, thermocouples, thermistors, vibrating wire piezometers, and pneumatic piezometers were installed in 18 observation wells as described by Chalaturnyk (1995). The results from Phase A were the main inputs in designing the Phase B monitoring plan. Nevertheless, Phase B monitoring was optimized based on the Phase A results and considering that the Well-pairs were more separated in the case of Phase B due to its larger scale compared to Phase A. For Phase B, recording frequency was optimized using the axiom: "you can monitor all of the pilot some of the time, and some of the pilot all of the time" (Collins, 1991). The main objective in both phases was to quantify the steam chamber's growth in the reservoir and ensure caprock integrity.

Monitoring programs are implemented in SAGD projects to optimize reservoir performance and manage subsurface risks, including caprock integrity. In-situ instrumentation, such as pressure gauges and thermocouples, is commonly deployed in observation wells for tracking the growth of steam chambers. Also, in some cases, temperature and pressure are measured at the caprock base to identify any upward flow (Aghabarati, 2017). Some projects also monitor pressure at the Quaternary formation to determine whether the caprock has been breached, as well as to ensure that the aquifers present in the formation remain intact (CNRL, 2020; Suncor Energy Inc., 2019a). Thermocouples, vibrating wire piezometers, and fibre optic sensors are some popular devices used in observation wells. Nonetheless, monitoring programs are typically not designed in consideration of engineering criteria, which leads to their being costly and inefficient in answering key safety questions.

Geomechanics-related monitoring in oil sands is typically carried out by measuring surface deformation. Different techniques that assist in measuring the ground elevation changes and that have been used in other geotechnical applications such as slope stability and ground settlement have gained popularity in the oil and gas industry. Thus, the adoption of techniques like InSAR and LIDAR is spreading rapidly in thermal recovery projects. Additionally, reservoir surveillance techniques such as 4D seismic and production curves (e.g., BHP, steam/oil rates) can be deployed in continuous monitoring to evaluate reservoir performance.

Accompanying Directive-086, AER also released the document RC-05, which discusses the various monitoring techniques used in thermal recovery (Dusseault, 2014). This document describes and reviews the efficacy of InSAR, LIDAR, GPS, levelling surveys, extensometers, tiltmeters, and microseismic monitoring, to name a few. However, while the report demonstrates the importance and outlines the advantages of monitoring, it underestimates the role an appropriate monitoring program may play in gaining understanding of the subsurface behaviour for the purpose of achieving optimal and safe operating conditions. Moreover, the report substantially explains the advantages and disadvantages of each technique and instrument in isolation but does not consider the potential value of a program that combines two or more of these techniques or instruments working in tandem.

In this section, the most popular techniques used in the thermal recovery of oil sands are reviewed and analyzed, identifying the strengths and weaknesses of each in the context of reservoir containment.

2.5.1 In-Situ Instrumentation

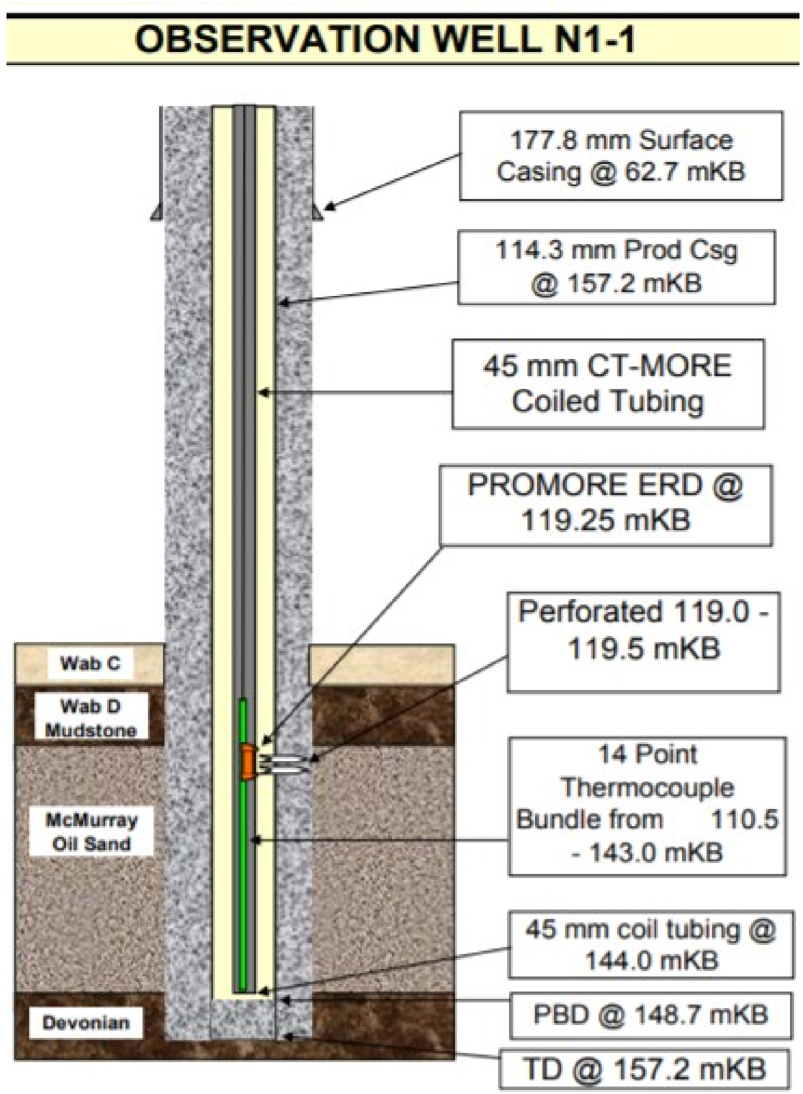
In-situ monitoring is performed using a variety of sensors placed in the subsurface. In-situ monitoring involves observation wells that extend to different depths depending on the information needed. Due to the wellbore drilling and completions required for this kind of monitoring, installing the sensors can be costly (Benham et al., 2018). Moreover, the exposure of sensors to the hostile reservoir conditions, such as high pressure, high temperatures, and even the presence of chemicals, for long periods further complicates the task of instrument selection.

SAGD projects are usually designed to span over 20 years to achieve the maximum recoverable volumes. The high temperature, which can range from 200 °C to 260 °C, is usually the main concern since relatively few sensors are designed to survive such conditions for a long period of time. Some of the issues that in-situ instruments face are stiffness changes in the rubber components (which may alter the seal capacity) and burning of electronic circuits.

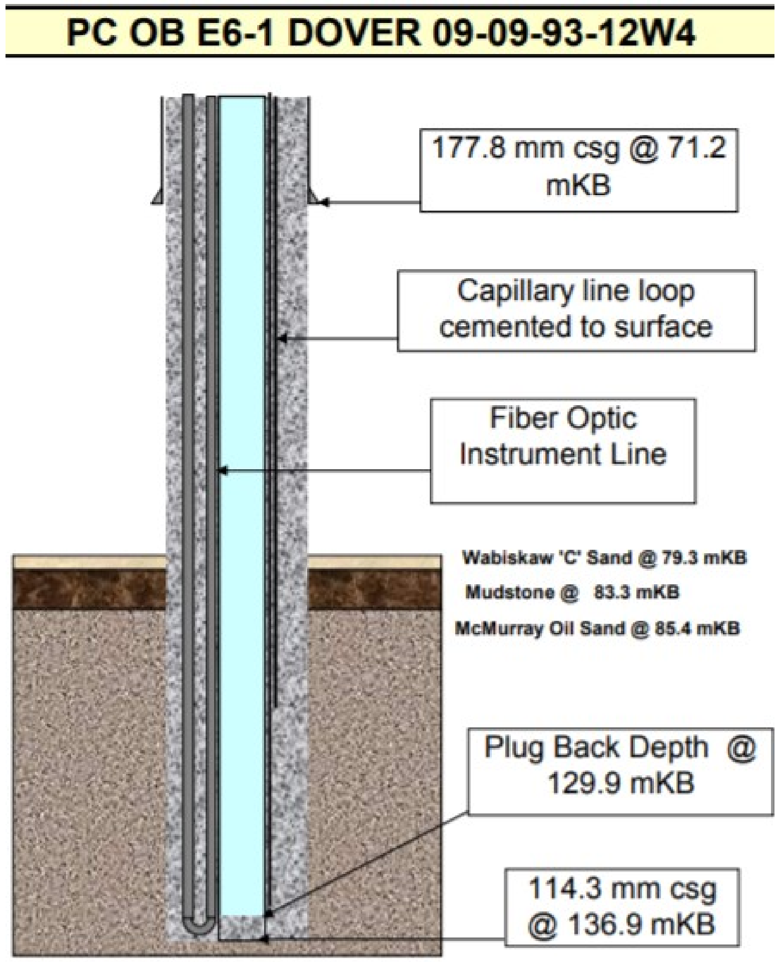
As sensors and data transmission technologies advance, so does observation well design; fibre optics, for instance, have proven very useful in observation well technology since it allows for the placement of several measurement points (depths) along the same well (Pinnacle, 2012). Fibre optic technology has been used to measure temperature, pressure, and strain (Pearce & Legrand, 2009). Thus, in-situ monitoring has progressed from measuring a few points along the well to continuous measurement at intervals and formations of interest. Although significant innovation has been achieved in the sensors used in thermal EOR, exposure to adverse conditions over a prolonged period remains a challenge. It should be noted in this context that observation wells can be drilled through the reservoir to monitor chamber growth or can be drilled just to the overlaying formations (such as caprock or Quaternary) as a way of identifying any leaks from the reservoir without exposing the sensor instrumentation to the hostile reservoir environment.

In-situ instrumentation in observation wells can be categorized as either (1) inside the casing, or (2) outside casing. The two require different completions, as shown in Figure 2-7.

- **Inside Casing**: also known as "internal instrumentation", is placed in a well that is cased, cemented, and perforated at the target depths (see Figure 2-7a). The sensors are usually isolated between formations to ensure that there is no cross-flow in the wellbore. Typically, both pressure and temperature sensors are installed in such applications since the measurements of these variables are highly correlated. This kind of instrumentation has the disadvantage of not being in direct contact with the formation, so readings can be affected by external conditions. In addition, the instruments are not capable of capturing hydraulic communication through the cement caused by cement failure. The infill material or fluid used in the wellbore must be well characterized to apply the appropriate corrections accordingly. For instance, the water's thermal expansion inside the wellbore can lead to high pressure readings that are not accurately representative of what is occurring within the reservoir. Moreover, well/casing deformation caused by the formation's thermal expansion can alter the pressure inside the wellbore. The method's main advantage is the convenience of calibrating, repairing, and replacing the sensors since the wellbore is easily accessible from the ground surface.



a)



b)

Figure 2-7 Observation well instrumentation. (a) Inside casing. (b) Outside casing monitoring instrumentation at Suncor's MacKay River SAGD Project—originally published in Suncor Energy Inc. (2019b)

- **Outside Casing:** also known as external instrumentation, is placed inside a capillary tube located in the casing–formation annulus. Once it is placed, the annulus space is cemented to fix the sensors and to ensure adherence of the casing to the formation wall. The inside of the wellbore is usually isolated from the formation. This type of observation well has the advantage of direct contact with the formation, meaning that corrections are not required. The main disadvantage, meanwhile, is that it is challenging to calibrate, repair, or replace a damaged sensor since the instrumentation is not easily accessible from the surface.

SAGD injector and producer wells are often equipped with downhole monitoring devices capable of tracking the temperature and BHP along the wells. This monitoring technique provides crucial information during the circulation phase to confirm communication between the wells. Temperature monitoring aids in identifying steam conformance between the injector and producer to ensure adequate bitumen displacement. Finally, BHP is monitored to ensure that operating conditions are within the acceptable range in terms of safety.

2.5.1.1 Temperature monitoring

As mentioned above, reservoir temperature is commonly measured as a way of tracking steam chamber growth. Chamber growth analysis, then, helps us to understand the lateral and vertical velocity of the heat front as well as the steam chamber architecture. The steam chamber growth velocity and architecture, in turn, are critical pieces of information in efforts to reduce geological uncertainty by identifying reservoir quality and petrophysical heterogeneities, such as low permeability or high water saturation zones. For downhole temperature monitoring, the most common devices are thermistors, thermocouples, Resistance Temperature Detectors (RTD), and Distributed Temperature Sensing (DTS) (Mills, 2011).

Two different mechanisms are involved in heat transfer during SAGD, convection and conduction (Butler et al., 1981; Edmunds & Gittins, 1993). Heat transfer mechanisms are mainly governed by petrophysical properties. Hence, in areas of the reservoir where effective permeability is high and fluid flow is allowed, convective transfer is dominant. On the other hand, the conductive mechanism is dominant where there is no fluid flow (low effective permeability). Temperature sensors installed in the reservoir are commonly used to monitor heat transfer from the injector to the reservoir (Wang, 2009). Figure 2-8 illustrates a typical temperature profile obtained from Athabasca Oil Corporation's Hangingstone Project. As can be seen, the figure shows temperature measurements and fluid saturations for three different times, and gamma-ray log and facies are also included in the plot for the purpose of analyzing heat transfer. (The different mechanisms that contribute to the temperature recorded are pointed in the temperature track). On the saturation logs, red corresponds to steam, while green corresponds to bitumen. The steam chamber grows vertically by convection in the part of the reservoir containing sand and breccia of excellent quality, while conduction is dominant at the top of the reservoir, where more IHS is present. The chamber growth rate at IHS is lower than in the sand due to the lower vertical permeability. Finally, Figure 2-8 shows some increase in the temperature above the reservoir after two years. Due to the low permeability of the caprock material in this region, heat transfer occurs as a result of conduction through rock and pore fluid.

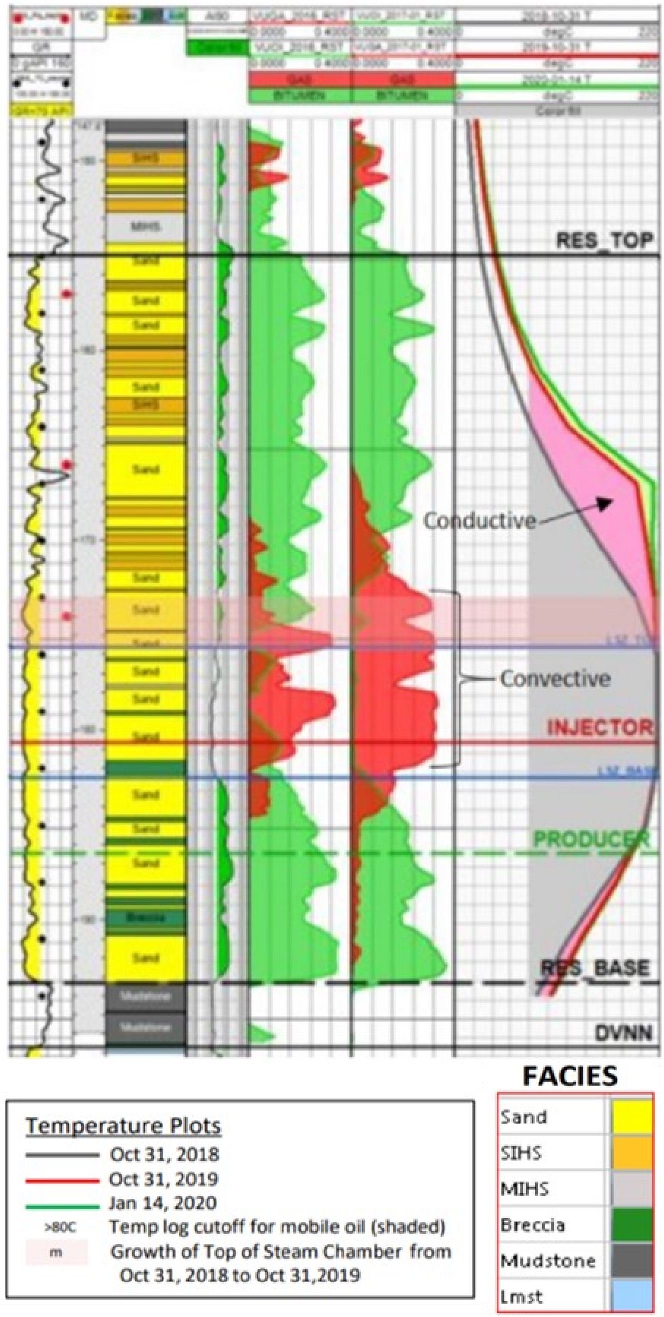


Figure 2-8 Typical temperature and saturations profile for Athabasca oil sands at three different times for Hangingstone Project, obtained from AER D54 2020 11888

2.5.1.2 Pressure

Pressure is monitored in SAGD projects for various reasons: (1) to ensure that values are kept in the safe operating conditions within the reservoir, (2) to identify steam thief zones, and/or (3) to identify leakage from the reservoir to the upper layer (reservoir containment). Depending on the given objectives, the specifications of the sensors and the location of instruments will vary. For instance, to monitor the pressure in the reservoir, instruments capable of functioning at high temperatures are required. In contrast, when identifying pressure changes in the upper layers, the instruments are not necessarily exposed to high-temperature conditions and thus resistance to high temperatures is not a consideration in the instrument selection in such cases.

Pressure sensors are among the most common monitoring instruments used in geotechnical engineering to measure pore pressure and associated effective stress. There are several options for devices in geotechnical engineering; however, vibrating wire piezometer is the most popular pressure monitoring device for SAGD applications (Mills, 2011; Zatka, 2016). For reservoir containment, the instrument can be installed at the upper formations to identify upward fluid flow. Usually, permeable formations such as sand are selected in order to increase the investigation radius, since pressure disturbance can extend further in more permeable formations. In some cases, wells are simply drilled and completed to the desired depth, a practice that reduces installation cost. It is also common to locate sensors in the shallow geological formation of the area (Quaternary) as a way of identifying caprock breach. As explained in section 2.1 above, permeable sand layers above the reservoir can also be used to monitor upward flow.

Figure 2-9 illustrates the temperature and pressure response in the Wabiskaw sand formation at PetroChina Canada’s MacKay River project. The figure shows a sudden increase in pressure and temperature observed in December 2018 for Pad AD. This abnormal behaviour signals reservoir containment loss. In this particular case, according to PetroChina Canada, the root cause of the behaviour was a communication to the lower part of the well through the cement (PetroChina Canada, 2019). In such cases, corrective actions such as remedial cement workover can be taken. On the other hand, if the rise in pressure is found to be associated with reservoir containment issues, additional measures must be taken accordingly, such as reducing the injection pressure and performing further investigations.

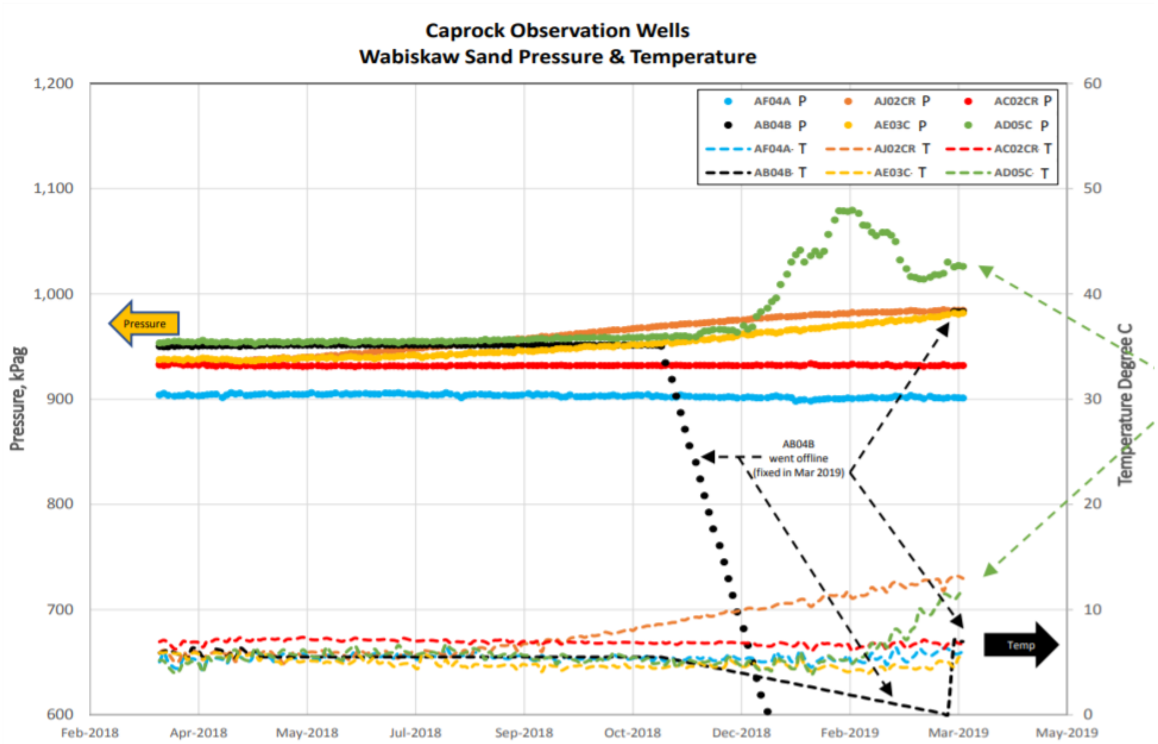


Figure 2-9 Temperature and pressure behaviour over time at Wabiskaw sand formation in PetroChina Canada's MacKay River project—originally pubplished in PetroChina Canada (2019)

2.5.1.3 Deformation

The deformation resulting from SAGD can also be measured using downhole instrumentation. However, this technique is not as common as surface deformation techniques due to its high cost and the high risk of device malfunction due to the adverse downhole conditions (Collins, 1994). For UTF Phase A, horizontal displacements were measured using gyroscopes, assuming that the well-bottoms, located in Devonian carbonate, had not displaced horizontally and could serve as a suitable reference. The results of the Phase A monitoring program are presented in Figure 2-10. In this figure a symmetric deformation of the reservoir, due to thermal expansion of the solids and fluids in all directions, can be observed. The same figure shows a different deformation behaviour at the upper and lower parts of the reservoir. This difference is caused by facies changes (explained above) typical of the McMurray formation in the Athabasca region, where the lower part is considered clean sand and breccia, while the upper formation is composed of IHS. Horizontal deformation, it should be noted, is also affected by water saturation and the contrast of vertical and horizontal permeability, which govern the steam chamber's shape, as is analyzed later in this dissertation.

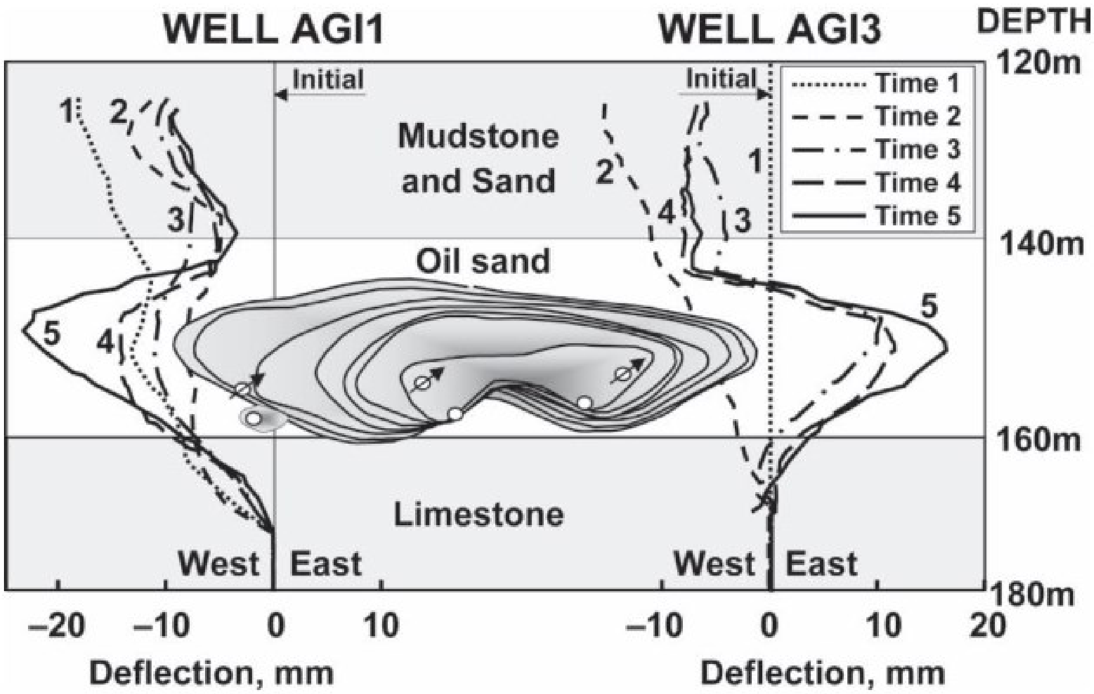


Figure 2-10 Horizontal displacements measured at UTF Phase A—originally published in Collins (1994)

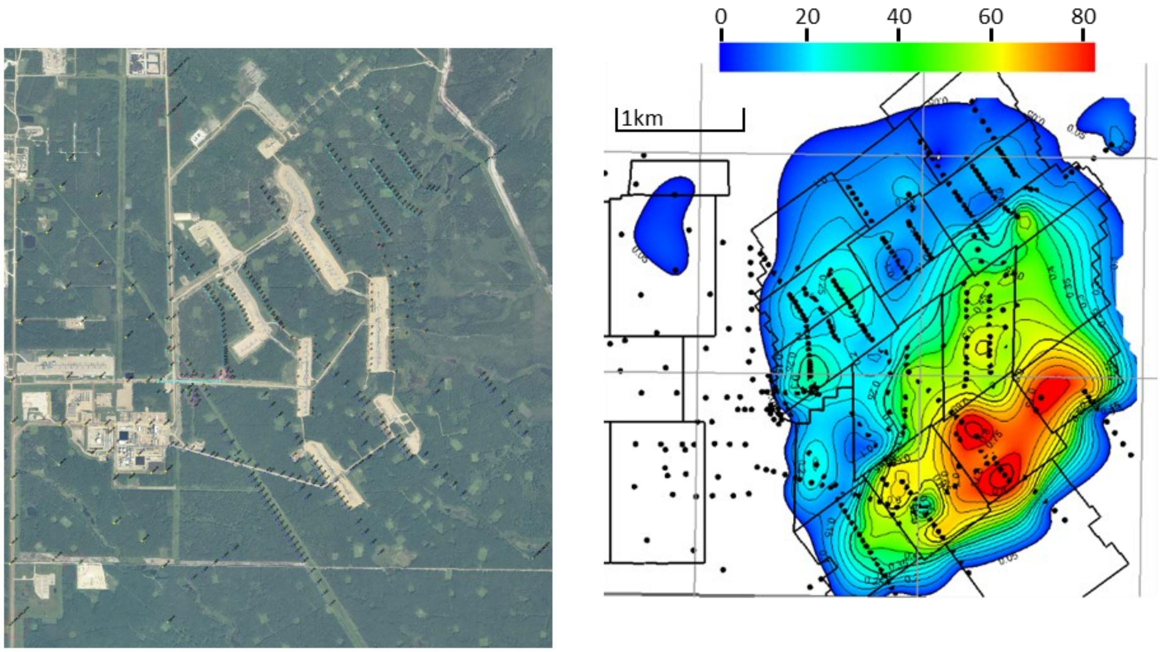
2.5.2 Surface monitoring

In current practice, geomechanics-related monitoring in SAGD projects is typically performed by measuring ground surface deformation. Looking at the publicly available data it can be concluded that all thermal projects in Alberta's oil sands use at least one kind of surface deformation monitoring technique. Dating back to the pilot thermal (CSS) projects in the 1970s, techniques such as survey monuments have been used to monitor surface heave resulting from steam injection. Unlike downhole monitoring, surface deformation monitoring does not require drilling/completion of wellbores, making it an inexpensive alternative for geomechanical monitoring. On the other hand, the fact that the measurements are not taken at the source of the disturbance increases the uncertainty of the measurements. Moreover, heave measurements can be affected by a number of factors, as will be discussed in CHAPTER 7, which explores the influence of weather and season on the recorded heave data by looking at corner reflector data from a SAGD project.

2.5.2.1 Levelling surveys

As mentioned above, conventional levelling has been used in oil sands since the 1970s, as Livesey showed in the Fort McMurray International Airport blowout analysis (Livesey, 2013). In that case, a heave as high as 16 cm was observed over a period of two years. The UTF Phase B pilot, meanwhile, was the first thermal project to have the number of instruments and their distribution planned based on geomechanical and process data (Collins, 1994). In total, 125 monuments were installed at the project to monitor the geomechanical response of the SAGD pilot.

Monitoring with levelling surveys, it should be noted, does have some disadvantages, as the low frequency of measurement intervals makes it unlikely to capture sudden events such as failure. Measurement frequency can vary from several weeks to months, limiting the possibility of measuring short-period processes, such as steam circulation or well-pair start-ups (ranging from 2 to 5 months). Additionally, the technique requires a clear line of sight, meaning that there could be an adverse environmental impact related to tree deforestation. Moreover, seasonal changes due to soil freeze/thaw cycles can severely affect the measurements if the pillars are not buried deep enough underground. Despite these issues, some SAGD projects still use this technique. One such example is Suncor's MacKay River case, presented in Figure 2-11, where a total of 420 monuments have been installed since 2002 (Suncor Energy Inc., 2019b). According to Figure 2-11b, the maximum cumulative heave measured over the production time was 80 cm at the end of 2018.



a) b)

Figure 2-11 Surface heave monitoring at Suncor's MacKay River Project using survey monuments. a) aerial picture of MacKay River Suncor project. b) Surface heave obtained from surveys—originally published in Suncor Energy Inc. (2019b)

2.5.2.2 Interferometric Synthetic-Aperture Radar (InSAR)

InSAR's low cost compared to similar technologies has led to its emergence as the most popular technology in thermal projects in Alberta. The technology uses satellites to detect ground motion with millimetric precision (Granda et al., 2008), a novel technique that has performed comparably well (see Figure 2-12). The fact that the measurements are taken remotely is also convenient, given the remoteness of some pads and the inherent accessibility issues in SAGD projects.

Vendors are continually increasing the number of satellites dedicated to InSAR, as well as increasing measurement frequency (Del Conte et al., 2015). InSAR can be deployed to measure surface displacement using corner reflectors or natural reflectors such as pipelines, towers, wellheads, and buildings, as illustrated in Figure 2-13. Although in some cases well pads are not located close to natural reflectors, with the presence of trees and brush necessitating the installation of corner reflectors, these instruments are still relatively inexpensive and lower maintenance compared to other technologies (Leezenberg & Allan, 2017).

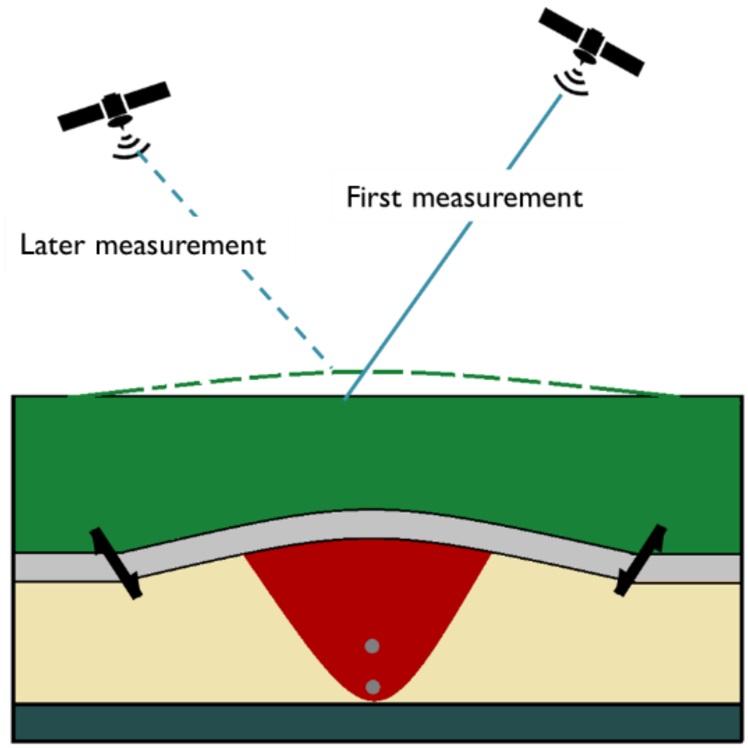


Figure 2-12 Schematic showing INSAR monitoring in SAGD.

On the other hand, this technology's main disadvantage is the data processing time, which could take several weeks depending on the number of points and the computation resources (Dusseault, 2014). The processing time represents a time lag from measurements to interpretation; thus, for real-time decision-making for safety and reservoir management purpose, InSAR's use has generally been limited.

InSAR using natural reflectors has been successfully applied to some thermal projects operated by Canadian Natural Resources Ltd. and Suncor Energy (Henschel et al., 2017; Tang et al., 2015). However, site vegetation and topography can affect the measurements; hence, corner reflectors may be required in some cases to acquire representative data of the area. Similar to the case with levelling survey, InSAR can also be affected by the seasonal changes typical of Alberta. If the corner reflectors' pillars are not correctly installed, the fluctuation of the ground level caused by soil freezing/thawing increases the likelihood of error in measurements.

Figure 2-13 Corner reflector and natural reflectors from an oil field in Alberta—originally published in Tang et al. (2015)

2.5.2.3 Tiltmeters

Tiltmeters are high-resolution inclinometers used to measure rotation and inclination in two different directions. They can be used in spherical coordinates to find 3D displacements analogous to the dip and azimuth directions. Thus, the readings can be used to calculate the displacement in the x, y, and z directions. Tiltmeters can be installed on the surface to measure the ground deformation, or downhole to measure in-situ displacement caused by differential deformation. Ground deformation is measured by placing tiltmeters into shallow wellbores with cemented PVC casing as illustrated in Figure 2-14.

Tiltmeters are commonly used in unconventional reservoirs to monitor hydraulic fracture propagation (Kikani, 2013). The main disadvantages of tiltmeters are the high cost, the data logger requirement, and the battery requirement to power the system. Some tiltmeters are furnished with solar panels as a way of resolving the dependence on battery power.

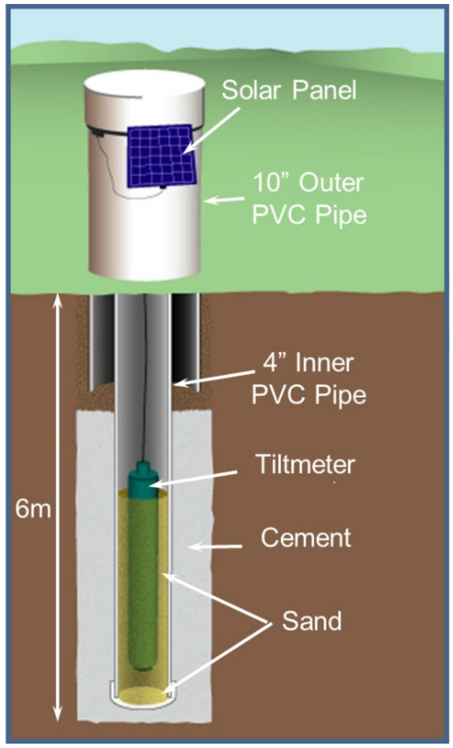


Figure 2-14 Scheme of tiltmeter installation

Tiltmeters are convenient for various applications, such as monitoring hydraulic fracture propagation in unconventional reservoirs, where the processes to be monitored usually occur over a span of a few weeks. In contrast, SAGD projects must be monitored from start to finish, a duration which typically ranges from 20 to 30 years. In addition, although tiltmeters are very precise at measuring differential displacement, they are less precise at measuring absolute displacement. For instance, if a tiltmeter is installed at the ground surface and the uplift is homogenous at that location, the device does not measure the uplift accurately.

Despite these disadvantages, Maxwell et al. (2009) demonstrated that tiltmeters could be successfully used for thermal recovery projects. They studied the deformation generated during SAGD using tiltmeters and evaluated microseismicity, finding that the tiltmeters were able to record substantially different uplift along the well, with the largest values measured at the toe and the heel. Microseismicity, recorded using geophones, was used to correlate dilation zones with surface deformation.

2.5.2.4 Microseismic monitoring

Microseismic monitoring can be defined as the process of measuring seismic events that have low magnitude and cannot be perceived by human beings. It is also known as “passive seismic” by geophysicists, because the seismic events are triggered naturally by flow/geomechanical mechanisms (McGillivray, 2004). Similar to tiltmeters, microseismic monitoring is commonly used in hydraulic fracture to monitor hydraulic fracture growth. Geophones can be installed on the ground surface or in-situ using observation wells to record microseismic activity/events.

Microseismic monitoring's main objective is to capture the fractures caused by fluid injection and thermal expansion in the reservoir and caprock (Lerat et al., 2010). Due to the unconsolidated nature of oil sands, their tensile strength is low, and so is the energy released from tensile fracturing. Hence, microseismicity is mainly used to monitor shear failure that can occur both at the reservoir and caprock (Dusseault, 2014). The main disadvantage of microseismic monitoring is the cost of the devices and the cost of the qualified professionals required to process and interpret the signal (for the purpose of identifying the location of the event).

2.5.2.5 Differential GPS

Measurements taken from conventional GPS devices have significant uncertainty (with a margin of up to 30 cm). Given this issue, the concept of “differential GPS” was introduced to reduce the uncertainty to levels as low as 1 cm. The difference between conventional GPS and differential GPS is that differential GPS uses a network of fixed ground-based antennas to broadcast the difference measured by the satellite and the known fixed antennas. This technology is widely used for geophysical monitoring applications such as the movement of tectonic plates and the relative displacement of faults. One of the main advantages of this method is that real-time measurements can be obtained, while the main disadvantage is the low accessibility of power supply for the antennas, given the remoteness of most SAGD projects.

2.5.3 Production/injection monitoring

Bottom Hole Pressure (BHP) and flow rate are continuously monitored in both injector and producer wells. This surveillance is the primary input for reservoir management and is used to make day-to-day decisions to improve reservoir performance. These methods are also used to optimize SAGD projects (i.e., to maximize oil production while minimizing steam generation). Since these readings are the main input for reservoir management, several software packages have been developed to help gather and visualize the resulting real-time data.

Although production/injection data is mainly collected for the purpose of optimizing reservoir performance, it can also be very useful for identifying and studying the reservoir's geomechanical behaviour. As explained in previous chapters, the deformation in the reservoir leads to changes in porosity and permeability, which in turn alter the reservoir's injectivity and productivity. For instance, if injecting at high pressure, effective stress reduces and the pore volume increases; thus, permeability also increases. According to Darcy's equation, if permeability increases and BHP remains constant, flow rate should increase, translating in increments of injectivity. This behaviour can be easily identified on injection curves because it represents how much steam the formation takes for a given BHP. For example, if injectivity increases while BHP is kept constant, the injection flow rate should increase.

In thermal recovery, increasing injectivity due to high injection pressure has been used as a strategy to increase the amount of steam injected in the reservoir and enhance permeability. For instance, at its Cold Lake operations, Imperial Oil injects steam at high rates in a CSS process to induce tensile fractures in the reservoir, and these fractures act as flow channels that allow steam to penetrate further into the reservoir (Boone et al., 1995). In this manner, enhanced permeability enables the injection of steam at high rates, reducing the duration of the injection and increasing the oil rate during production.

Injection at high pressure has also been used in SAGD projects for short periods during circulation to induce sand dilation. Sand dilation, it should be noted, occurs at the beginning of the plastic region and is governed by grain reorganization, resulting in permeability enhancement (Chalaturnyk & Scott, 1995). If high pressure is applied at the beginning of the project, the circulation time can be reduced significantly, and, accordingly, bitumen production can start sooner. This process also improves the well conformance since it creates a high permeability region around the wells (Yuan et al., 2011).

Production/injection curves have been very helpful when analyzing previous incidents in oil sands, as in the Joslyn case, where an anomaly of injectivity was identified one month before the well-known blowout (Figure 2-15). The yellow and magenta lines in Figure 2-15 describe the steam injection rate, while the purple line describes the BHP at the injector well. In this case the anomaly occurred around April 11, when the injection rate increased significantly, while the BHP slightly decreased. This behaviour is a clear sign of injectivity increase and may have been caused by the opening of a highly conductive channel (tensile fracture). To maintain the BHP at the injector well, the steam rate was then increased more than double and remained constant for several days. As the rate had stabilized at a higher value, the hydraulic fracture was growing, as described by Khani (2022). Due to the stress state of the areas in the McMurray formation, the fracture is likely to grow vertically, reaching the caprock. In this case, injection data was useful from a geomechanical perspective since it could capture the initiation and propagation of the fracture in the reservoir.

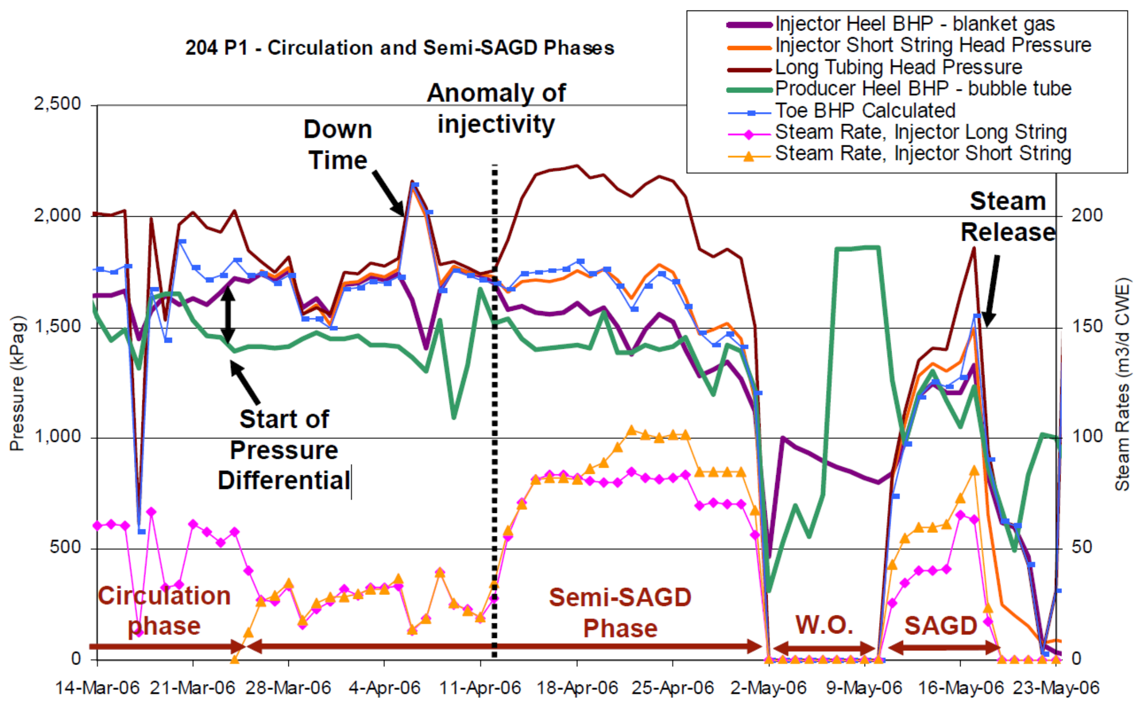


Figure 2-15 BHP and flow rate behaviour on injection well at Joslyn's steam release location—originally published in Energy Resources Conservation Board (2010)

Another important piece of information that should be tracked during SAGD is the Water–Steam Ratio (WSR), defined in Equation 2-1. WSR is used to indicate the amount of steam kept in the reservoir. This steam may be forming steam pockets, and as explained above, steam pockets can be pressurized and result in a catastrophic event, as was the case in both the Joslyn and Texaco cases.

$$WSR = \frac{produced\ water}{injected\ steam} \qquad 2\text{-}1$$

The main advantage of using production/injection for geomechanical monitoring is that it does not represent extra costs since the sensors to be used are already in place in the wells for reservoir management. This also means that the data is collected continuously, and agile and efficient visualization tools are available to be used in reservoir management. In addition, using this data effectively links geomechanical behaviour with reservoir performance to better understand the physics of what is occurring in the reservoir.

2.5.4 4D Seismic

4D seismic monitoring is a technology that has been successfully implemented in many oil and gas projects using fluid injection. It is performed by conducting 3D seismic analysis at different intervals throughout the project, as illustrated in Figure 2-16, capturing changes in density of the fluids that saturate the rocks and influence the wave speed through the porous media. Given that bitumen density is significantly higher than steam density, 4D seismic monitoring has been proven to be a powerful tool for monitoring steam chamber growth and shape, even for complex geologies, as shown by Zhang et al. (2007). In this work, they were able to identify geological features such as mud channels that act as barriers to steam chamber growth. More recently, Lerat et al. (2010) presented a study in which 4D seismic monitoring was integrated with high-resolution geological models to capture all the heterogeneities within the reservoir. The results show how useful 4D seismic can be in identifying steam allocation within the reservoir, even for complex geologies.

4D seismic has consolidated over the years as one of the main techniques for monitoring steam chamber growth, as well as for identifying the zones of the reservoir where SAGD is efficient and inefficient at recovering the bitumen in place. Identifying such zones helps to plan new developments and optimize drilling programs (Masih et al., 2014; Maxwell et al., 2009). 4D seismic monitoring is also used to history match reservoir numerical models in order to confirm the ability of the models to predict where steam will go within the reservoir (Hiebert et al., 2014).

Although 4D seismic is a valuable tool for monitoring steam chamber growth, and the material's mechanical behaviour is well correlated to wave velocities, 4D seismic application in geomechanical monitoring is still very limited. The main limitation is the frequency at which 4D seismic is commonly performed. It usually takes 2–3 years to repeat 4D seismic in a specific pad due to the logistics required and the cost of the measurements. In addition, 4D seismic has a high uncertainty with respect to vertical strain that limits its application for caprock integrity monitoring.

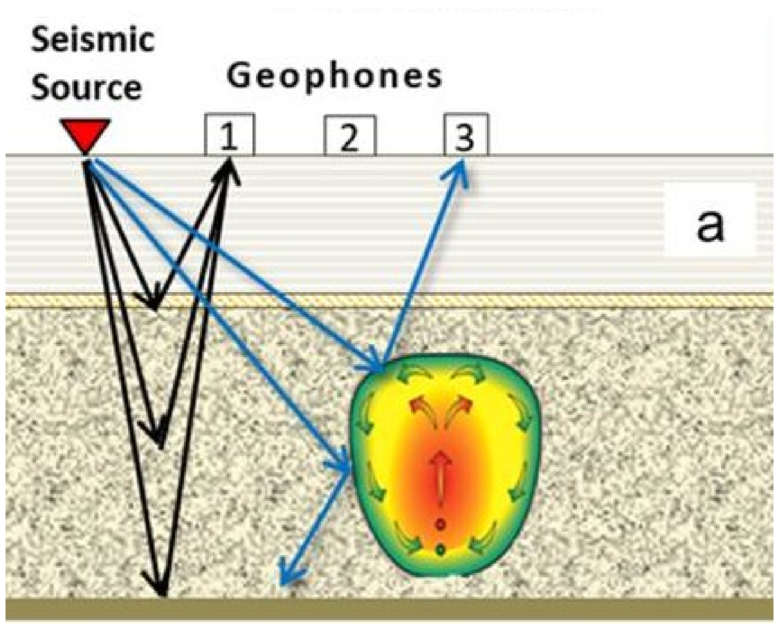


Figure 2-16 Schematic 4D seismic application during SAGD—obtained from (https://www.nrcan.gc.ca/)

CHAPTER 3 PLANNING MONITORING PROGRAMS FOR STEAM ASSISTED GRAVITY DRAINAGE (SAGD)

3.1 Introduction

Monitoring is a common practice in thermal projects in Alberta as a way of ensuring reservoir containment, and in fact a monitoring plan is typically required in order to obtain approvals from regulatory agencies. However, it is important to plan the monitoring carefully according to the requirements and objectives of the given project. Otherwise, the monitoring program ends up being costly and inefficient. Efficient monitoring designs should be based on engineering judgment or at least preliminary geological knowledge of the area at the beginning of the project, with a clear purpose in mind, as well as questions that need to be answered by observations. Although this may seem straightforward, monitoring programs are often encountered in the oil and gas industry that were implemented without appropriate monitoring design.

In geotechnical engineering, monitoring has been widely used to ensure project safety. Since the early days of geotechnical engineering, field observations have been crucial to improving soil behaviour understanding, assisting in decision-making, and ensuring the structure behaves according to the design. In this chapter, the adoption of a methodology commonly used in geotechnical projects (proposed by Dunnicliff) and its tailoring for use in SAGD projects is described. As described below, the particularities of SAGD projects, such as oil sands geology and the hostile environment associated with these projects, are considered at each step in the development of the systematic approach.

In his book, *Geotechnical Instrumentation for Monitoring Field Performance*, Dunnicliff, states: "Planning a monitoring program using geotechnical instrumentation is similar to other engineering design efforts, which begin with a definition of purpose and proceed through a series of logical steps to preparation of plans and specifications". Dunnicliff proposes a logic-based procedure for planning monitoring programs in geotechnical engineering projects. In the same text, Dunnicliff continues, "Unfortunately, there is a tendency among some engineers and geologists to proceed in an illogical manner, often first selecting an instrument, making measurements, and then wondering what to do with the data". It is worth noting that Dunnicliff recommends monitoring to be used as a tool to improve understanding of the subsurface behaviour; as such, the value and usage of various data should be identified during the design stage. Given the unique needs of SAGD projects, some steps in the procedure proposed by Dunnicliff may not be necessary, but it is recommended to go through all of them to ensure a robust monitoring program design.

Given the cost associated with monitoring programs in SAGD, key questions about the project must be carefully considered in the selection and installation of every instrument. Peck (1969) stated in his work, "every instrument installed on a project should be selected and placed to assist in answering a specific question. Following this simple rule is the key to successful field instrumentation". Successful monitoring programs can increase understanding of the subsurface behaviour, thereby allowing operators to maximize project performance while managing the principal risks. As per the discussion in the previous chapter, monitoring offers a range of benefits regarding the operation of SAGD projects:

- Providing warning of unexpected behaviour that may compromise the safety of the operations.
- Improving reservoir performance and project economics.
- Obtaining data for model calibration and history matching to improve forecasting.

3.2 Monitoring in geotechnical engineering and The Observational Method

Monitoring has played a key role in geotechnical engineering projects since the earliest stages of this discipline and the introduction of the observational method. Peck (1969) published an analysis of the observational method and his discussions with Terzaghi, outlining its advantages and limitations. The observational method, it should be noted, refers to designing flexibility into projects based on observations obtained from instrumentation in the field. This method is premised on the possibility of changing some parameters during and after construction based on observations that modify the initial design.

The observational method as described by Peck can be summarized in terms of three steps: (1) preliminary design based on the initial exploration, (2) monitoring plan to verify that the construction behaves within acceptable limits, and (3) design of a contingency plan in case the boundaries of acceptable behaviour are breached (Spross & Johansson, 2017). According to Peck's definition, it is crucial that the design can be modified if required at any time in order for the observational method to be successfully applied.

The observational method aims to improve the geotechnical engineering project "as it goes" to ensure the ongoing safety of the construction. Powderham (1994) published an overview of the observational method, noting that the method should be applied only in projects that have the potential to achieve savings in cost or time. More recently, Spross (2014) performed a critical review of the method, suggesting that it could be improved upon through its integration with the probabilistic method. Calvello (2017) proposed updating the numerical models based on the observation results in order to improve understanding of the soil and thereby reduce uncertainty.

The substantial experience and knowledge gained in monitoring for geotechnical projects has also been successfully applied in other industries facing similar challenges, such as mining, to ensure safety of operations (Eberhardt & Stead, 2011). Thus, monitoring programs are key inputs in decision-making, allowing operators to minimize project costs while maintaining safety.

3.3 A systematic approach to planning monitoring programs in SAGD projects

The workflow for designing monitoring programs proposed by Dunnicliff is presented in Figure 3-1, and each step within the workflow in the context of SAGD application is detailed in this chapter. Applying a logic-based workflow for monitoring design in SAGD results in a strategic monitoring program designed to answer the main operational questions that allow ensure reservoir containment.

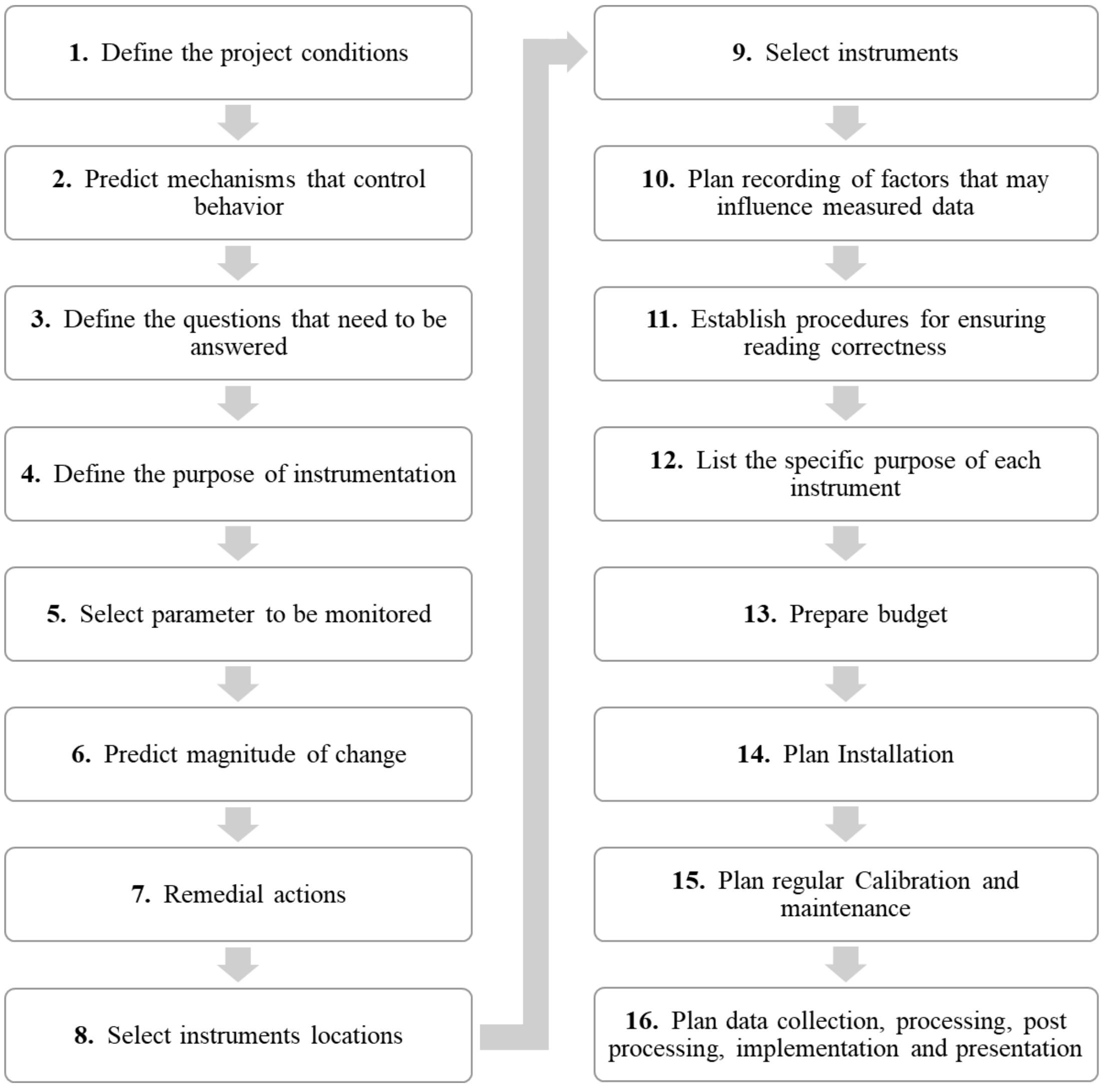


Figure 3-1 Workflow for systematic approach to designing geotechnical monitoring as proposed by Dunnicliff (Modified from Dunnicliff, 1988)

3.3.1 Define the project conditions:

This step includes the general and specific conditions of the project. Although Dunnicliff states that it may not be necessary if the team planning the monitoring is familiar with the project, this step is important because it represents the foundation of the subsequent steps. Specifically, in SAGD, this step is vital because, many times, monitoring programs are not designed by the operators of the project. In addition, monitoring programs in SAGD must be designed to span the life of the project, which may be 20–30 years. Over the course of this lengthy period, many different professionals may be overseeing project monitoring. Appropriate documentation explaining the initial condition and concerns of the project during monitoring design can be useful for future reference to aid understanding of the initial design and objectives. The initial conditions that must be defined in SAGD may include:

- **Geology of the area**: This includes the stratigraphy from the ground surface to the rock underlying the reservoir, since the influence of SAGD operations in the subsurface is not limited to the reservoir. It is essential to identify the engineering behaviour of the materials, the mud bodies in the reservoir (as they govern the steam chamber shape), and the sand or silt layers in the caprock that can act as flow channels. It is also necessary to evaluate the presence of discontinuities in the formations, as they usually represent weakness planes and flow pathways. Understanding initial in-situ stress is also important since the behaviour of the materials is usually stress-dependent. The in-situ stress estimation can be challenging due to the depth and the complex geodynamics of the given area, and, thus, uncertainty must be considered. The geological description must also identify any kind of fault, seismic feature, or discontinuity that could be activated or displaced by SAGD operations.
- **Hydrogeology and environmental conditions**: This point could be grouped with the previous one, but, given its importance in risk management, it is recommended that it be treated separately. This includes identifying water bodies in any formations and their communications. If there are water bodies within the reservoir, the determination of salinity and composition is important as a way of tracing any water migration to the upper layers. In addition, the identification of underground aquifers is crucial (including its intended use, whether for irrigation, livestock, or for feeding steam generators) as a means of ensuring they are readily available and satisfy the required characteristics. Finally, it is also important to identify running water and water bodies at the surface so that appropriate measures can be taken to protect them from contamination.
- **Surface facilities**: when planning monitoring programs, there should be an inventory of all surfaces, buildings, and infrastructure within the project area. This includes field camps, processing plants, wellheads, roads, and pipelines, to name a few. It is also important to consider the tolerance of the infrastructure to

surface deformations. In this case, monitoring should work as a warning to ensure such tolerance is not exceeded.

- **Subsurface infrastructure:** subsurface infrastructure includes well design, casing sections, casing steel specifications, cement quality, packers, any installed devices, any instrumentation for SAGD operations and observation, and any abandoned wells in the area. In this regard, analyses of previous incidents have identified that the presence of wells in the area can play a key role in reservoir containment loss.
- **Operating conditions:** this includes temperature, pressure, injected fluids (steam, solvent, etc.), and artificial lift mechanisms. This information is useful for predicting the response of the subsurface and instruments, as well as for selecting the appropriate devices for the specified conditions.

3.3.2 Predict mechanisms that control behaviour

Predicting subsurface response to steam injection is still challenging due to all the uncertainties in material characterization and modelling of the subsurface. For this purpose, a complete program for geomechanical characterization of all the formations is important, as this approach can be used to predict the response during thermal recovery. The predictions should include the various scenarios encompassing the principal uncertainties inherent in the system. If uncertainty is high, it is recommended that a conservative approach be taken to ensure safety even in adverse conditions.

For geomechanical response prediction, it is recommended to use numerical analysis, but if there are costs, information, or time limitations, analytical tools can be used for preliminary design (Azad, 2012). The main concerns identified as a result of forecasting, as well as the uncertainty of the model should be taken into consideration in the analysis. Moreover, based on the information gathered from the previous stage, practitioners must consider what could go wrong, identifying worst-case scenarios and endeavoring to predict monitoring response under such conditions.

When predicting mechanisms that control behaviour, geological heterogeneity and discontinuities such as fractures and faults must be included. Also, constitutive models that can predict the materials' behaviour should be considered. Constitutive models include deformation and flow models to help estimate changes in the variables that can be monitored, such as pressure, temperature, and deformation. At this stage, operational or safe limits can also be estimated and incorporated into the monitoring program accordingly.

This step should also consider the behaviour and risks at both the early and latter stages in the project. For example, at SAGD start-up, there is more risk of fracture initiation and propagation within the reservoir that could extend to the caprock due to the reservoir's low effective permeability (bitumen saturated). Later in the project, meanwhile, the effective permeability of the chamber increases, resulting in significant fluid leak-off and thereby reducing the likelihood fracture initiation. However, the deformation in the caprock at the latter stages of the project increase, since the steam chambers are fully expanded, increasing the exposure area to heat, pressure, and loads.

3.3.3 Defining the questions that need to be answered

Defining the questions that need to be answered is the most important step in the design; nevertheless, it cannot be adequately done if previous steps have been missed. The questions that need to be answered from the monitoring program should be clearly identified to select the optimal instrumentation. In this stage, it is important to consider that some questions cannot be directly answered by measurements. In some cases, measurements must be processed, interpreted, and analyzed to answer the questions at hand, and some questions even require the analysis of multiple measured variables together to arrive at the correct answer. For example, pressure changes in the caprock can be caused by flow upwards or by undrained thermal expansion of the fluids caused by heat transfer (conduction). In this case, temperature measurements are valuable for identifying whether the pressure changes observed are the result of temperature changes.

Some questions that commonly need to be answered in SAGD projects include:

- Where is the steam chamber growing?
- How fast is the steam chamber growing?
- Is pressure changing in the caprock?
- Is temperature changing in the caprock?
- Is there fluid flow in the caprock?

- Is there water phase changing in the caprock?
- Is SAGD injection opening/generating high permeability paths?
- Is there flow in the Quaternary formation/is the caprock breached?
- How much steam is being kept in the reservoir?
- Is casing/cement intact in the wellbores?
- Is injection pressure higher than designed?
- Is the caprock deforming as expected?
- Are deformation, pressure, and temperature occurring at the same location?
- Is surface heave within the tolerable limits to ensure infrastructure safety?
- Are the faults in the area displacing?

Answers to these questions aim to identify key mechanisms for events leading to reservoir containment loss. For instance, measuring pressure changes in the caprock can help identify pathways to the upper layers and can be complemented with other data such as casing/cement integrity or injectivity data to determine the root causes of loss of containment and take remedial actions.

The questions posed above are associated with reservoir performance and operational safety. If possible, it is recommended to consider the two components of monitoring together since they are closely correlated, and this can result in a more cost-effective monitoring design. For example, deformation should be expected in the reservoir, where steam chamber growth is more prominent.

3.3.4 Define the purpose of instrumentation

There are two main purposes of instrumentation in SAGD projects: (1) reservoir performance and (2) project safety. In-situ monitoring programs can be costly, making it crucial that a comprehensive and tangible purpose be identified to justify the investment. In this respect, Peck (1984) stated: "the legitimate uses of instrumentation are so many, and the questions that instruments and observation can answer so vital, that we should not risk discrediting their value by using them improperly or unnecessarily".

Often monitoring devices are installed in thermal projects with no clear purpose, overlooking or underestimating their real value. When designing monitoring programs, it is crucial to understand the importance and value of the information being measured by the instrument. The value of the information can be easily appreciated when the monitoring is directly helping to increase bitumen production, but it can be more difficult to quantify when the purpose of the monitoring is to ensure safety. To justify the extra effort involved in monitoring for reservoir containment, the cost of previous incidents can be reviewed.

3.3.5 Select parameters to be monitored

This step could be straightforward if the previous step is done carefully. Once the questions that need to be answered have been clearly identified, identifying the parameters that need to be measured to answer these questions is a reasonably straightforward task. Dunnicliff separates these parameters into two categories: (1) causes and (2) effects. For example, parameters such pressure and temperature in the reservoir are the cause, whereas the surface heave/deformation is an effect. However, thermal recovery is a complex process in which any given parameter can function as either cause or effect depending on the given situation. For instance, high pressure can cause fracture generation that will also result in pressure drop. Therefore, the measured parameters end up being highly correlated, and, thus, the most representative or inexpensive parameter to measure can be selected as the target of the monitoring. In addition, sometimes the measurements can be examined in a complementary fashion to draw certain conclusions.

Ultimately, it is important to bear in mind that the operator controls the main "cause" parameters in thermal recovery (pressure and temperature). These parameters are the operating conditions that are set in such a way as to maximize the recovery and safety of operations, which means that these parameters may be changed during the project if required.

3.3.6 Predict magnitude of changes

The range of magnitude of the variables measured must be predicted in advance in order to select the most appropriate instrumentation. To estimate ranges of magnitude, sophisticated or simple tools, such as numerical or analytical modelling, can be used. This consideration is critical when selecting the specifications of instruments, such as precision and accuracy. The maximum predicted values can be used to select a cost-efficient instrument. In general, instrument accuracy is directly proportional to cost. Also, high accuracy and sensitivity usually correspond to more fragile instruments that are not sufficiently robust to stand up to lengthy periods of exposure to hostile conditions. On the other hand, predicting the minimum value will help to identify the accuracy and sensitivity limits that would be at play when measuring the parameter of interest. For instance, sometimes there is more interest in measuring the rate of change of a parameter than the absolute value; in such a case, an instrument must be selected that is sufficiently sensitive to capture these changes.

It is also essential to predict the limit values that could be associated with adverse events. In this way, alarms and warnings can be set in the monitoring design to ensure appropriate action is taken in a timely manner. For this purpose, a traffic light methodology can be useful in setting three different levels of alarms—green, yellow, or red—depending on the risk level. In addition, it is important to predict and understand mechanisms that control the behaviour at failure conditions to take the appropriate decisions.

3.3.7 Remedial actions:

When using monitoring as an alarm or warning to avoid an adverse incident, it is important to plan in advance the actions that would be taken in response to a risk identified during the observations. It is also important to set the alarms at a level that gives sufficient time to the operators to take the corresponding remedial actions.

In SAGD, alarms can be set when the pressure or temperature observed in the caprock exceeds the operating limit. Additionally, if there is a sudden injection drop (change in injectivity), actions must be taken to avoid fracture propagation. The remedial action could be to reduce the injection pressure to a safe level or shut in the injection pump if necessary. Sometimes, it is required to interrupt the project, at least within a localized area, while further investigation is carried out to determine the actual risk of the operations.

3.3.8 Select instrument locations

The locations of instruments should be carefully selected to maximize the value of the information obtained from the observations and should reflect the predicted behaviour obtained from the preceding steps as described above. In-situ monitoring is expensive due to the high cost of drilling and completing deep wellbores. Therefore, the instrument locations should be optimal to gather as much information as possible with the fewest observation wells. If the locations are not properly selected, the monitoring program can end up being costly without adding significant value to the project.

Based on the geology of the area and the predicted behaviour, critical monitoring locations can be identified. These critical locations are zones of particular concern, such as faults, differential consolidation, sinkholes due to karsting and salt dissolution in the underburden, weakness planes, incised channels, or weak materials in the project area. Among the predicted mechanisms that control behaviour as described in section 3.3.2 above, load concentration in the caprock can be identified at critical locations. Pressure and temperature at the base of the caprock are transferred as a load due to the thermal expansion and reduction of pore pressure. Thus, zones where steam chambers are expected to grow significantly should be treated as zones of concern. Critical zones can change over time due to the dynamic nature of steam injection at all SAGD stages. The optimal locations to cover the different stages can be prioritized based on safety considerations or considering the value of the information. Critical zones can also be identified in such a manner as to protect surface infrastructure; in this case, instruments' locations are limited to the infrastructure's location.

Moreover, the location should be selected based on predicted values, and instruments should be installed where the parameters are expected to change the most. In this regard it should be noted that large measurements usually mean less sensitivity is required (i.e., the instrumentation required will be less expensive). Another consideration is that the monitored location should be representative of the area to maximize instrument coverage.

In SAGD projects, the location definition includes both surface coordinates and depth, and this makes selecting the location a challenging task. On the other hand, the location of a single well can be chosen based on the amount and value of information that can be obtained at different depths or formations at the same location. When using monitoring to identify risks related to reservoir containment, the sensor should be installed at a depth that gives the personnel sufficient time to react to avoid an incident. The number of locations depends on the critical zones identified within the project and the cost associated with installation. Furthermore, the durability of the instruments should be considered as well; some regions within the steam chamber may have hostile conditions (high-temperature and corrosive environment) that can cause sensor malfunction after prolonged exposure. When monitoring in such environments, it is critical that instrument maintenance, repair, and replacement be carefully planned in advance. Moreover, since the optimal monitoring location can change over time, some budget should be set aside for additional monitoring during the execution of the project if new critical zones are identified.

3.3.9 Select instruments

This step is often the point of entry when planning monitoring programs; however, it is recommended to complete the previous steps before carrying out instrument selection. In the original approach proposed by Dunnicliff for geotechnical engineering, the instruments themselves are selected prior to identifying the locations. However, selecting the location before selecting the instrument itself is preferable in SAGD due to the different conditions that the instruments may face. For example, conditions in the reservoir are harsher than in the formations above; therefore, a piezometer installed in the reservoir must meet the high-pressure, high-temperature requirements, while a piezometer installed in the Quaternary need not.

When selecting the ideal instrument for the application, conditions such as reliability, temperature, pressure, chemical conditions, and cost must be carefully evaluated. When evaluating the monitoring program's economics, for instance, the various instruments under consideration should be compared in terms of overall cost of procurement, calibration, installation, maintenance, durability, and processing. Often the least expensive instrument is not reliable and/or has significant maintenance requirements. It is also important to consider all the additional costs involved when selecting the instruments (e.g., the extra costs of remote and harsh access conditions of some SAGD projects, especially when the instruments are located far from a road, or the extra cost of locating instruments in observation wells that require the mobilization of extra equipment to access the downhole for calibration, maintenance, or replacement).

Finally, the instruments selected and the methodology for installation must not increase the project's risk level. When using observation wells to install instruments, the wells must be completed in such a manner that isolation is guaranteed and it does not represent a threat to the subsurface containment.

3.3.10 Plan recording of factors that may influence measured data

Several external factors may affect the measurements recorded by the instrumentation, including temperature changes, rainfall, soil freezing/thawing, road traffic, and drilling of new wells, to name a few. Temperature changes caused by seasons have a significant effect on surface deformation monitoring. For example, during the winter months, Alberta's temperature can drop to values as low as −60 °C, while in summer it can exceed 30 °C. These extreme changes cause freezing and thawing of the soil and, subsequently, thermal expansion and contraction. To capture the influence of weather, some instruments can be deployed for benchmarking purposes. Such instruments should be located where changes in deformation due to project operations are not expected. Additionally, high precision instruments such as tiltmeters and geophones can be affected by the vibrations generated by traffic on nearby roadways. They can also be affected by drilling in nearby wells disturbing the subsurface. Thus, any abnormal behaviour in the instrumentation must be identified and examined in the context of any unusual activity in the area. Another condition to be considered in SAGD operations is the change in the water table that can be registered in piezometers installed in the Quaternary formation during the spring and summer months due to rainfall and snow melting. CHAPTER 7 presents a detailed analysis of seasonal influence in surface heave monitoring in a case study.

3.3.11 Establish procedures for ensuring reading correctness

Those responsible for monitoring programs must ensure that instruments are functioning correctly. If device malfunction is identified, a correction plan should be followed in order to maintain sound observations. There are different sources of devices malfunction as calibration problems, loss of communication, loss of power source, or device damage. Monitoring planning should include a plan to for addressing all these scenarios, should they arise. While the problem is solved, the measurements should not be included in the monitoring system to avoid false alarms. When the information measured at a particular location is critical, it is recommended to consider a backup device that can be used to take measurements while the primary device is being repaired/replaced.

3.3.12 List the specific purpose of each instrument

At this point in the planning process, it is worthwhile to list selected instruments with their corresponding purpose as a way of organizing the approach and helping to revisit the monitoring design to determine whether all the selected instruments are in fact needed. In some cases, instruments can be left for later consideration as the project progresses and more information becomes available. All the instruments that have a clear purpose within the monitoring plan, though, should be retained on the list.

3.3.13 Prepare budget

Once the final list of instruments is obtained from the previous step, the design budget is to be estimated. Then, the design team must ensure that sufficient budget is available to deploy the monitoring program. It is important to bear in mind in this regard the duration of the project and the costs associated with data collection and post-processing to cover the lifetime of the project. If the available budget for monitoring is insufficient for the designed program, it may be necessary to curtail the program. The list prepared in the previous step can be helpful for evaluating how the monitoring program could be downsized, if necessary. On the other hand, if the monitoring program requires more budget, it should be supported by reasons that can be defended considering the monitoring plan.

3.3.14 Plan Installation

This is a significant step and should be done in advance to ensure the success of the operations. If drilling and well completions are required, the plan should allot sufficient time for these operations to be executed. Many instruments are delicate and fragile, and special precautions need to be taken to ensure the correct functioning of the instruments. It is important to read all the recommendations provided by the manufacturer of the instruments for correct installation. Installation of downhole devices can bring extra challenges due to the limited space and the lack of visual verification. Moreover, in most cases the installation personnel are different from the design team; it is for this reason precisely that all the procedures and special considerations during installation should be clearly stated prior to installation, and that all installation personnel should have the appropriate training and adequate understanding of the procedures.

3.3.15 Plan regular calibrations and maintenance

Monitoring observations are only reliable if the instrument has been properly calibrated. Planning calibration and maintenance for SAGD instrumentation is an important part of monitoring design since it may require gear, personnel, and logistics. If the instruments are installed downhole, it can be difficult to calibrate them in place, in which case they should be brought to the surface. Depending on the weight of the downhole assembly, special heavy lift equipment may be required, and the associated logistics should be planned in advance. In addition, calibrations and maintenance should be scheduled with plenty of time due to the accessibility challenges of SAGD projects in some months of the year.

3.3.16 Plan data collection, processing, post-processing, implementation, and presentation

This is the final step of this monitoring design approach and is carried out to determine whether all the personnel and hardware resources are available for implementation. This is one of the most important steps because it organizes how the monitoring results will be implemented and presented. Today most data is collected automatically and in digital format. Nevertheless, some monitoring techniques still require manual readings that must be scheduled. The frequency at which data is collected should be evaluated, and this consideration may also be decisive when selecting the instruments. It is imperative that planners not underestimate the effort required for data processing and implementation. In many cases, not all data is processed due to a lack of time, computational resources, or trained personnel. As such, it is also imperative that personnel be properly trained for data processing and interpretation, and that the necessary hardware and software for these tasks are available. In some cases, it should be noted, data pre-processing is performed by the sensor vendor.

Recent advances in computational and statistical fields such as data science and data analytics allow for the efficient handling of large amounts of data. Sometimes, due to the large number of instruments used and the high frequency of reading, the collected data needs to be filtered and organized after collection. To ensure the optimal use of monitoring data, all the data should be processed in such a manner that it can be easily visualized and analyzed. As explained above, it is also critical to carefully question the data; if the instruments are not properly calibrated, the data will not be reliable. Moreover, it is important to check whether external factors may be affecting the measurements; if so, all this data should be removed or corrected, since it will not be representative of the actual project behaviour. If the data needs to be corrected according to step 10, it should be done in the pre-processing stage.

If post-processing and calculation are required, an efficient and agile way of carrying this out by programming spreadsheets or codes to obtain monitoring data that is ready for plotting and visualization should be established. It is recommended to prepare a template for data visualization; this should include the relevant information to perform a complete analysis for helping to understand the behaviour. Often, the measurements increase the value when it is complemented by details of the project as operating conditions, location, depth, formation, distance to Well-pairs, and distance to main surface and subsurface structures. Including such information helps to contextualize about what is happening and where it is happening. In this way, the physics of the process that resulted in the measurements can be presented in a comprehensive manner.

It is also helpful to plot and analyze different monitoring data, such as pressure, temperature, and deformation, together, given that, as explained above, it is likely that these data are correlated. In some cases, there is a delay between responses that helps to aid understanding of what is occurring. For example, in the upper layers it is common to observe pressure increase due to undrained thermal expansion, and the temperature change is recorded before the pressure change. More examples of correlated data are provided in CHAPTER 5.

It is also recommended to plot the observed vs. predicted data, as this helps with calibrate and improving future measurements and predictions. Monitoring represents a significant investment of resources, and the results should be used to improve understanding and predictions for future reference. Proxy models based on historical data and machine learning are simple and useful tools for forecasting. They can be continuously calibrated as new data becomes available.

It is recommended that periodic reports and presentations be prepared to make the team aware of the performance of the project and any operational concerns that may have been identified. Finally, a well-organized and documented final report of observation data will be of great value for other engineers and geologists who may be interested in understanding the project's behaviour.

CHAPTER 4 HIGH-RESOLUTION MODEL FOR THERMAL FLOW GEOMECHANICS SIMULATION

4.1 INTRODUCTION

Including geomechanics in thermal reservoir simulations requires a geomechanical model that includes both flow and deformation properties. First, the model is built using geology information as formations tops and faults in the area. Then, every formation is divided into cells that are populated with the corresponding flow and geomechanical properties.

In this chapter, a high resolution geocellular model that captures the geological heterogeneity of the reservoir and caprock is constructed for one SAGD pad in the MacKay River project, operated by PetroChina Canada in the Athabasca deposit. The model is assumed to be the best representation of the subsurface and as such, is considered as a “truth” model for establishing the possible ranges of behaviour during the SAGD process. The model is used as a virtual environment to test different operating conditions and the associated monitoring response.

The model also includes the formation above the caprock that extends towards the surface and the formation below the reservoir. The model is built using different types of public information and data gathered from the literature, such as horizon tops, well logs, laboratory data, and regional tectonics. Frequently, this information comes in different formats and resolutions that should be normalized to obtain the best representation of the subsurface in the area.

Building the geomechanical model is fundamental for assessing thermal recovery's geomechanical response and the associated surveillance program. According to the Systematic Approach introduced in CHAPTER 3, the first step is to define project conditions, and building a geocellular model is part of this first step where all the geological information is included. Thus, the static model should reflect the geology of the area and the constitutive models that govern the subsurface behavior. To achieve this, 3D and heterogeneous models that capture the geological setting that could affect SAGD performance and measurable parameters as temperature, pressure, and deformation, should be developed.

4.2 MacKay River PetroChina Canada Project

The MacKay River Commercial Project commonly referred to as "MRCP", is a SAGD project owned and operated by PetroChina Canada "PCC". It is located approximately 30 km northwest of Fort McMurray, as presented in the red area of Figure 4-1, and the depth of the reservoir within the project area is 175 meters on average

This ongoing project started in early 2000 and aims to reach a maximum production of 150.000 bbl/day. Phase 1 of the project includes 8 SAGD well pads with 42 horizontal well-pairs in total, as shown in Figure 4-2. The wells are 850 meters long, the spacing between Well-pairs is 125 meters on average, and the producer and injector are 5 meters apart. The wells were drilled and completed by 2014, and the surface facilities were finished in 2016. The steam injection of Phase 1 started in December of 2016, and bitumen production started at the end of 2017, having a production capacity of 35.000 bbl/day. The high-resolution geomechanical model presented in this chapter corresponds to Pad AE, as illustrated in Figure 4-2.

Figure 4-1 Location of PetroChina Canada MacKay River SAGD project. Modified from (http://www.oilsands.alberta.ca/)

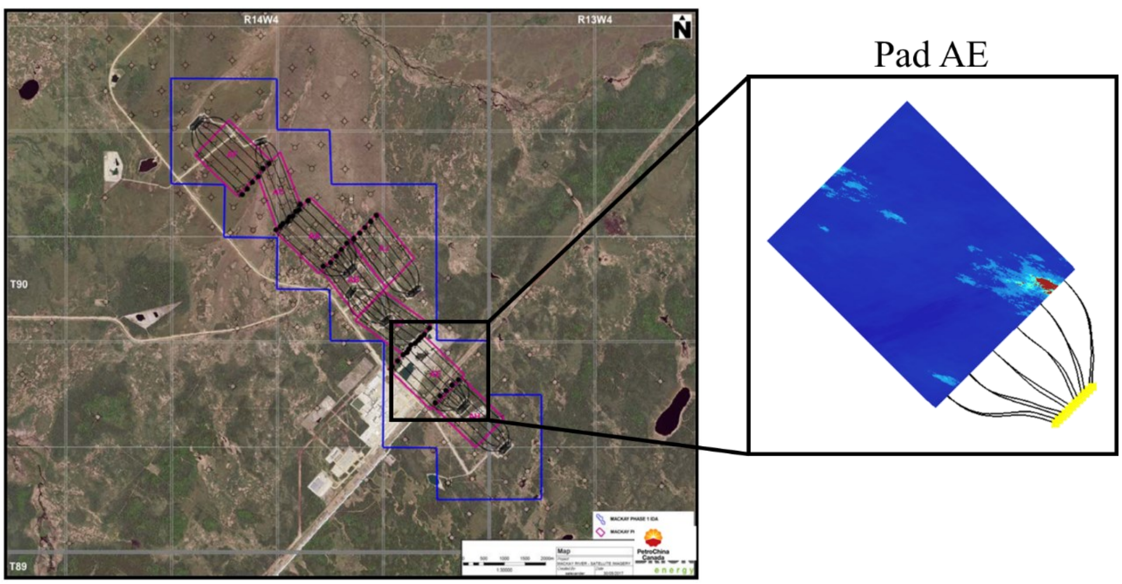


Figure 4-2 Pad AE used for geomechanical model construction and the development project area of MRCP.

4.2.1 Stratigraphy

The stratigraphy of MRCP is similar to other projects in the Athabasca region, but in some cases, formations are absent due to erosion or depositional environment changes, as explained in 2.1. Figure 4-3 presents a well from the MRCP showing the typical stratigraphy found in the area from the ground surface to the formation below the reservoir. The first 60 meters of the column correspond to Quaternary deposits, which are composed mainly of glacial Till. At the base of this formation, the surface casing is settled to isolate the aquifers and the well. The sediments can be classified as poorly selected since it is composed of sediments of different grain sizes that range from pebbles to fine clay, as described by Andraishek (Andraishek, 2003). The behavior of gamma-ray and spontaneous potential logs suggests that the formation is permeable and hydraulically connected. Under-laying the Quaternary deposits, there is the Sub-Cretaceous unconformity that has also been reported by Andraishek (Andraishek, 2003). At the top of the Cretaceous deposits is the Grand Rapids formation that corresponds to a continental clay and sand sequence. These two formations, Quaternary and Grand Rapids, are considered overburden for geomechanical modeling and will be treated as a single formation due to the lack of geomechanical data. At the base of the Grand Rapids Formation is the Clearwater Formation, a marine sequence that can be divided into two main sections, as illustrated in the stratigraphic column. The upper section corresponds to an interbedded shale and fine sand, while the lower section is known as Clearwater Argillaceous and is commonly referred to as shale, as described by Huag et al. (2014). This lower Clearwater section is the main caprock of the area, and its thickness ranges from 15 to 30 meters within the project area.

The Argillaceous Lower Clearwater is underlain by the Wabiskaw unit, which is a member of the Clearwater Formation. The Wabiskaw Member is subdivided, from top to bottom, into Wabiskaw Sand and Wabiskaw Shale. Wabiskaw Sand is usually saturated with water and some gas, and this section is used to monitor reservoir containment in many projects of the area, including MRCP, since it is immediately underneath the caprock. Wabiskaw Shale is a thin impermeable layer at the top of the reservoir that acts as a first barrier that prevents the upward propagation of fluid.

The McMurray Formation is the target reservoir of the project. The thickness of the reservoir in the development area of the project ranges from 10 to 25 meters, and it is mainly composed of quartz sand grains with some interbedded silts and clay sections, as shown in the resistivity logs presented in Figure 4-3. From the logs, it can also be interpreted that the target formation is mainly saturated with bitumen. In some parts of the project where the top structure is high, some gas saturation was previously reported (Petrochina Canada, 2018). There is a transition zone at the top of the McMurray Formation, a thin layer (<1 m) saturated with water and hydraulically communicated with the reservoir. Since the zone is saturated with water, it could act as a steam thief zone due to the high water mobility affecting the growth of the steam chamber and subsequently, it should be considered when planning the monitoring program.

Finally, the last formation that is included in the geomodel is the formation underlaying the reservoir. There is a geological unconformity at this interface that results in having a formation much older than McMurray sand. Thus, the formation below McMurray corresponds to a carbonate that was deposited in the Devonian age (500 Ma) and can be identified as a hard rock due to the geomechanical behavior reported by Chalaturnyk (1995).

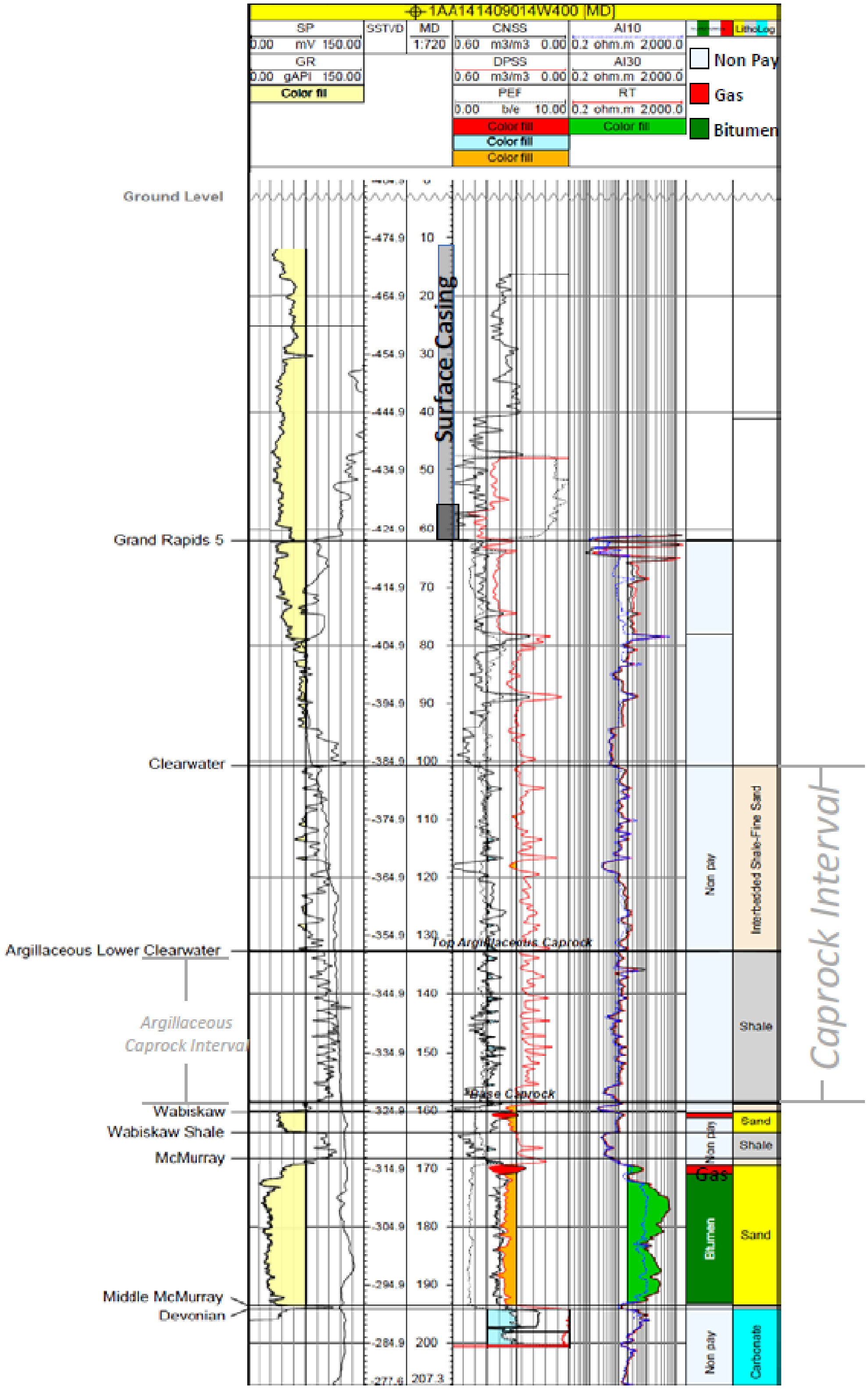


Figure 4-3 Typical stratigraphy and well logs in MacKay River Commercial Project area.

4.3 Static model

The geomodel is created using a specialized software called The SKUA GOCAD (©Paradigm) that integrates geophysics, geomodelling, and gridding. Formations tops from public data are used to build the layer horizons illustrated in Figure 4-4, where the surfaces represent the top of each formation included in the stratigraphic column; these surfaces are later used for layering the geomodel.

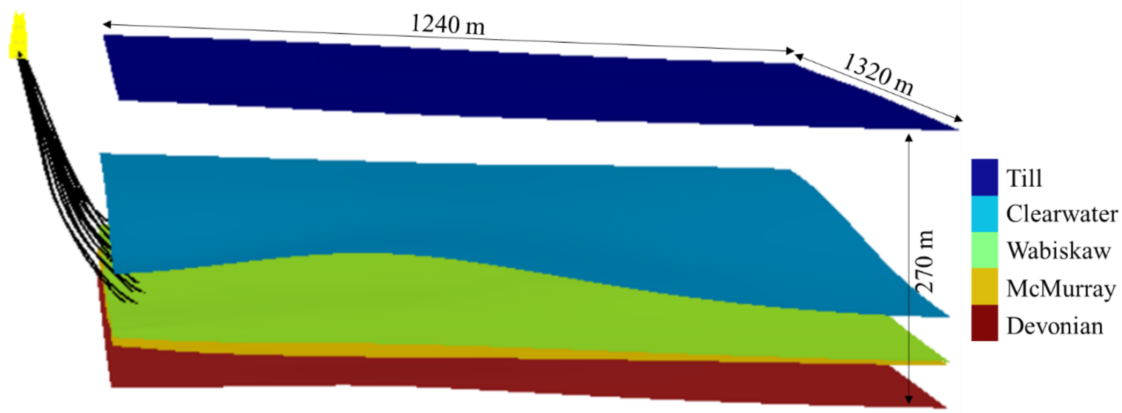


Figure 4-4 Stratigraphic horizons for Till, Clearwater, Wabiskaw, McMurray, and Devonian formations at Pad AE MRCP.

The geomodel is created such that it contains different sedimentary layers based on the formation's horizons shown in Figure 4-4. In this way, the geomodel follows the structure of the formations and any depositional features, such as erosion or incision channels. To simplify the layering and due to lack of geomechanical information, Grand Rapids formation is included in the Quaternary deposits and is named "Till." The resulting geomodel layers constructed from formation horizons are presented in Figure 4-5.

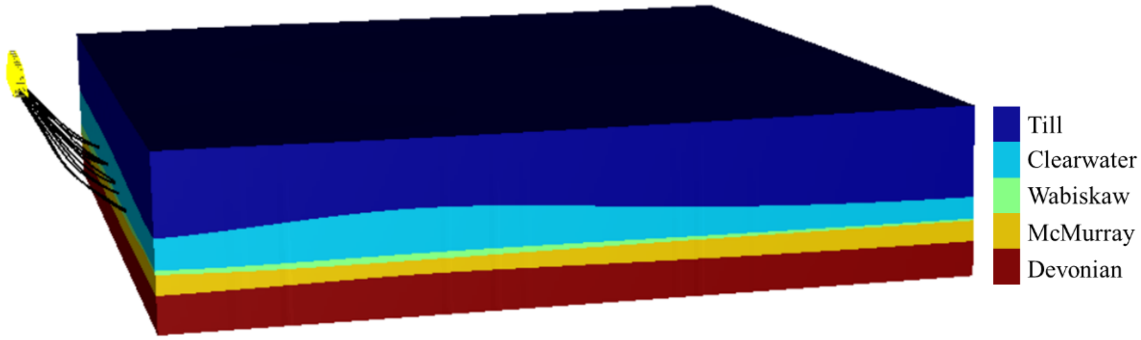


Figure 4-5 Layers constructed from horizons in the geomodel

Once the geological layers are defined in the geomodel, the gridding for simulation can be completed using tartan grids that allow gridblocks of different sizes. Tartan grids are used to capture as much detail as possible in some areas of interest, such well-pair vicinity where pressure, temperature, and stress change the most; and less detail in the far field improving computation efficiency. The cells in the reservoir area are grid blocks of 6x6 meters, while in the external area, larger grid elements are used as it approaches the model boundary reaching a maximum of 12 m. Grid cell thickness also changes for the different formations having a higher resolution at the reservoir as presented in Table 4-1. Grid's wireframe is illustrated in Figure 4-6.

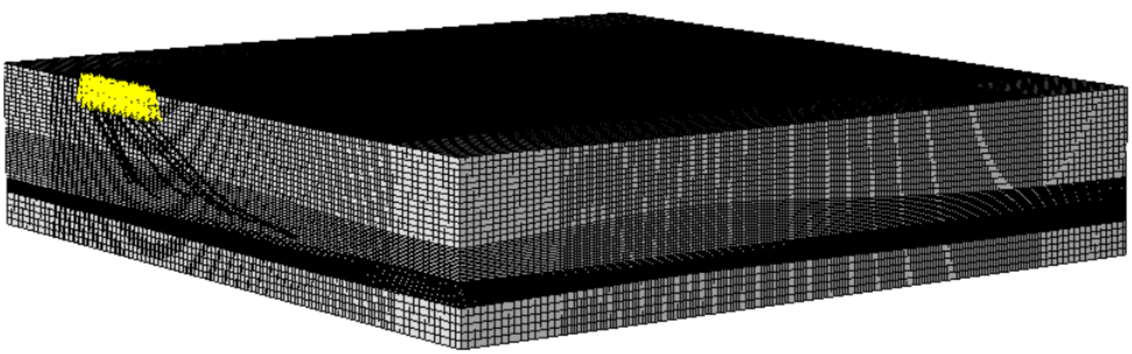


Figure 4-6 Grid-frame of Geomodel for Pad AE MRCP.

4.3.1 Outer and inner simulation domains

In coupled geomechanical-flow simulations, it is recommended to separate flow/thermal boundary conditions and deformation boundary conditions (Settari & Walters, 2001), and thus, two different domains are used: 1) flow/thermal model and 2) geomechanical model.

Table 4-1 Geomodel layering

Formation	Number of layers	Layer thickness (m)	Total average thickness (m)
Till	14	8	72
Clearwater	15	4	60
Wabiskaw	4	3	12
McMurray	16	1.5	24
Devonian	18	3	54

The flow model is where fluid flow and heat transfer occur, and it is part of a larger model used for geomechanical simulation, as illustrated in Figure 4-7. In this way, there is no pressure and temperature disturbance at the boundary of the outer domain, which is mainly controlled by far-field or regional stress state. The flow model includes the reservoir, Wabiskaw formation, and part of Clearwater to investigate pressure and temperature changes at these zones. Even though typically, there is no flow upwards into the caprock formations, in many cases, temperature changes have been reported at the base of the caprock according to previous analysis of monitoring data (Aghabarati, 2017). If no flow is confirmed from numerical simulation, other mechanisms control the heat transfer upwards, such as conduction. In the flow model, different heat transfer mechanisms are evaluated to predict such behaviors. Additionally, as previously mentioned, Wabiskaw sand is commonly used to monitor reservoir containment, since in many cases, Wabiskaw shale acts as a first flow barrier. Thus, simulating the pressure and temperature changes in Wabiskaw sand is crucial to understand and predict how monitored variables should behave in this monitoring zone.

The geomechanical model is extended both laterally and vertically to simulate the impact of SAGD operations in the surrounding formations, such as the caprock and the surface. In fact, it is very important to simulate surface data since surface deformation is the most popular monitored variable in thermal projects.

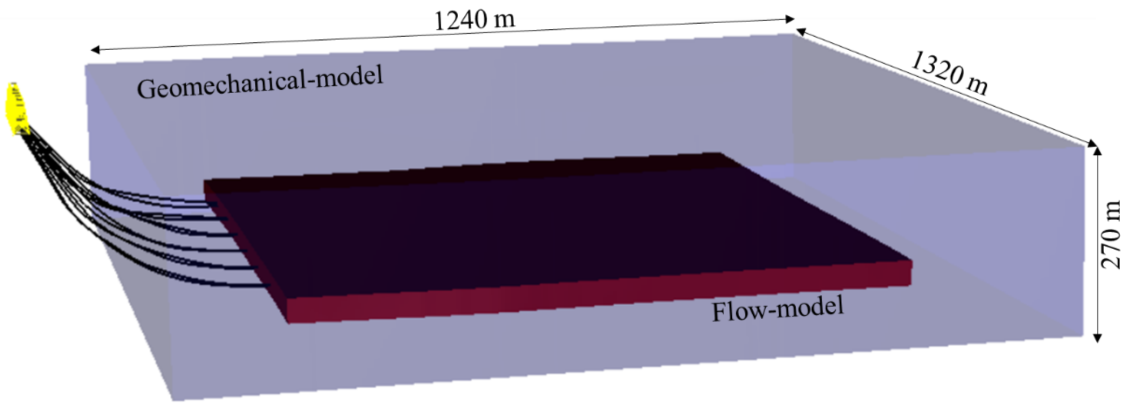


Figure 4-7 Flow model and Geomechanical model for Pad AE in MRCP.

4.3.2 Facies distribution

Reservoir and caprock formations in oilsands have been described as heterogeneous formations composed of sand, clay, and silt. Usually, grain size distribution is a good indicator of the depositional environment and the associated energy of the transport media during settlement. Due to changes in the depositional environment, it is common to find interbedded bodies inside these formations that may affect their flow and geomechanical properties. Such is the case of the inclined heterolithic stratifications (IHS) found at the top of McMurray formation, which may act as a barrier for steam, and even thin seams of clay in the reservoir can control the growth of the chamber. In the case of the caprock, silt presence can likely control the formations' geomechanical behavior since silt can be associated to weaker zones. Although many geological layers are too small to be captured in the geomodel, their presence should be considered while modeling to obtain reliable predictions.

As part of the geocellular model, the heterogeneity of the caprock and the reservoir is analyzed using gamma-ray log. Gamma-ray is a measurement of natural radioactivity from geological formations, and it is the most used geophysical log to discriminate lithologies such as sand and shale. As radioactive isotopes are more common in clays than sand, gamma-ray measurements are usually correlated to the amount of clay particles in the formation. For this model, a cut-off of 75° API is used to distinguish between sand and clay, consistent with the current regulation proposed by the AER (AER, 2016). Once the facies distribution is calculated, QA/QC of the model is performed to ensure that the model honors field data. Facies distribution is also used to populate petrophysical and geomechanical data in the reservoir and caprock in later analysis.

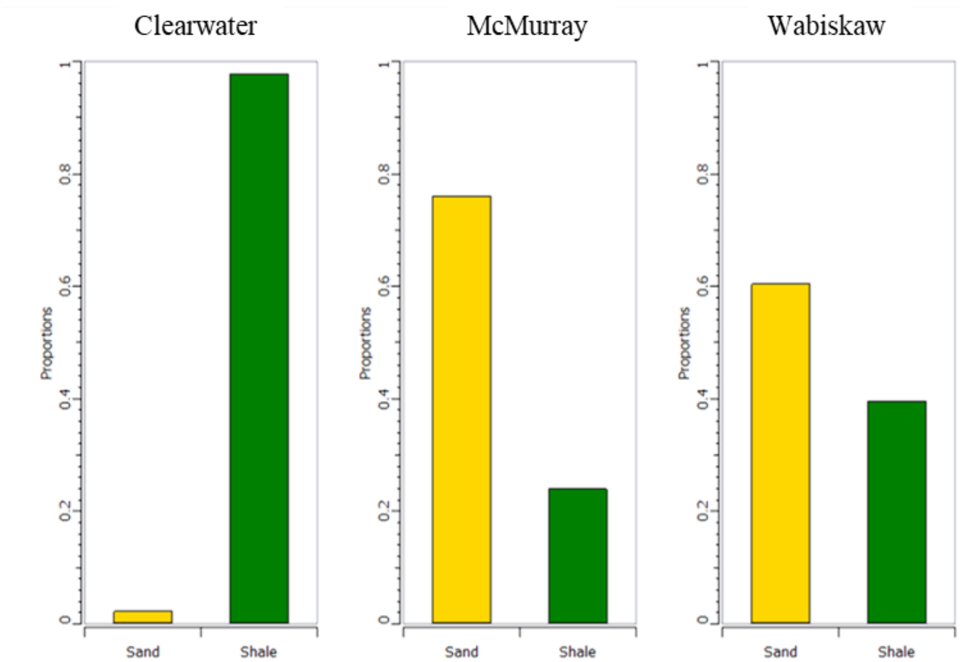


Figure 4-8 Facies distribution in each formation

Figure 4-8 illustrates the facies distribution obtained for the geomodel of Pad AE. The figure shows that the reservoir's predominant facie is sand, while in the caprock shale dominates, as expected. It is important to mention that there is more percentage of clay at the lower Clearwater, which is in good agreement with the geological description of the formation, according to Huag (Huag et al., 2014). Figure 4-9 presents the facies distribution in the model. As mentioned before, lower Clearwater is also known as Argillaceous Clearwater and is considered the main caprock of the Athabasca area. The percentage of coarser grains as silt and sand is crucial to understanding the caprock's geomechanical behavior since they can be associated with weaker zones, as will be explained later in this chapter. These zones are also of high interest for monitoring since they can transmit pressure changes in the caprock.

However, monitoring permeable zones in the caprock can be challenging due to limitations in lateral continuity. Lateral continuity of permeable zones in the caprock can be estimated by analyzing logs, seismic, and geological models together. It can also be tested using well-testing techniques such as build-up tests or interference tests to evaluate the continuity and connectivity throughout the caprock.

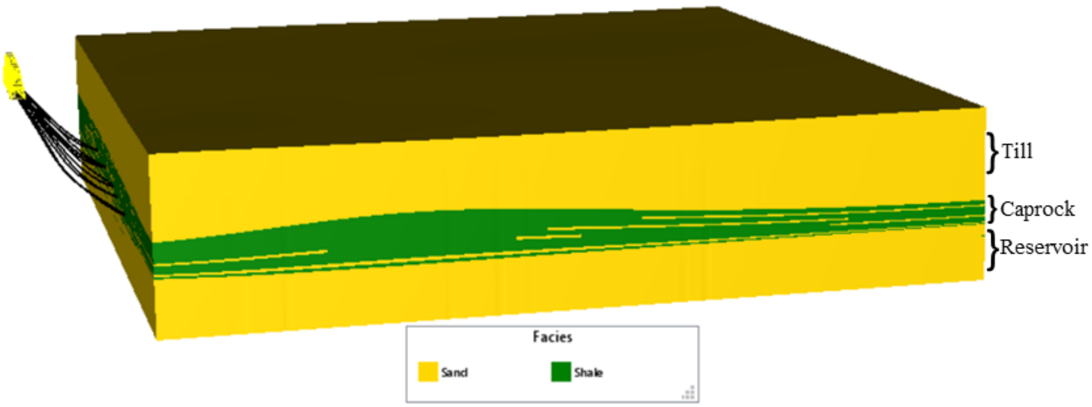
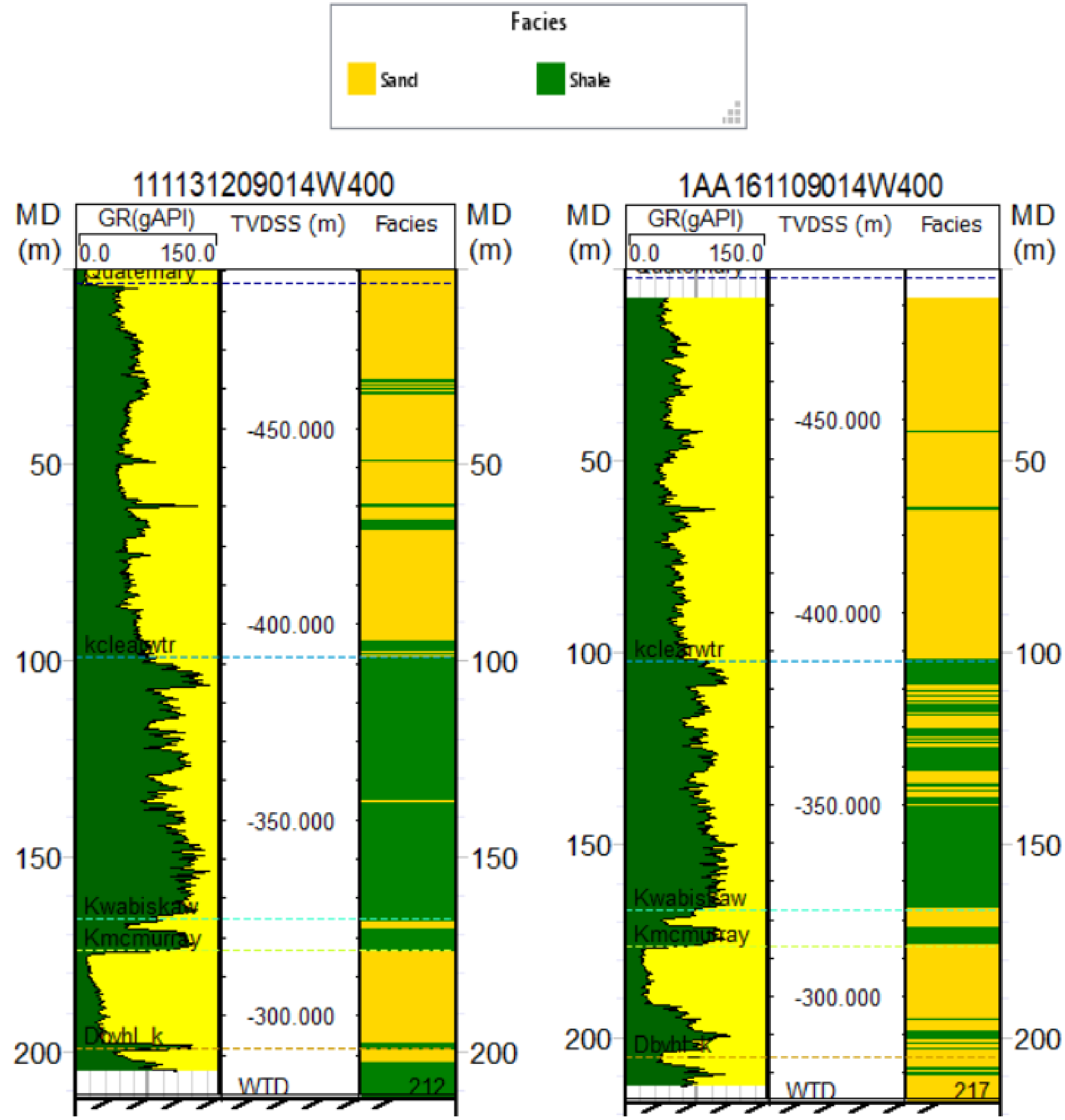


Figure 4-9 Facies distribution in Geomodel

Even though the geomodel was built just for the pad area, significant heterogeneity can be identified within it, as is illustrated in Figure 4-10. The well presented in Figure 4-10 a) is located northeast close to the toe of Well-pair2, while the well in Figure 4-10 b) is located west of the area. The first track corresponds to the gamma-ray log, and the second track shows the estimated facies distribution in the model for the two different wells.

There is a clear differentiation between Upper Clearwater and Lower Clearwater in Figure 4-10 b) due to sand/silt presence at the top of the Clearwater formation. In contrast, Clearwater formation for the well presented in Figure 4-10 a) is homogenous through the interval with a thin sand layer in the middle. The reservoir is more homogeneous to the well presented in Figure 4-10 a), which will result in a larger steam chamber compared to the other well.

Finally, throughout the studied area, the Wabiskaw formation can be divided into two sections, Wabiskaw shale located immediately above the reservoir and Wabiskaw Sand located above Wabiskaw Shale. Wabiskaw Shale could act as the first barrier to prevent flow to the upper layers, and thus, Wabiskaw Sand is monitored to identify flow given the low amount of shale and the lateral continuity throughout the area.



a) b)

Figure 4-10 Gamma Ray and Facies distribution for two different wells.

Petrochina Canada has classified facies in the McMurray formation based on heterogeneity and interbedding of mud, silt, and sand (PetroChina Canada, 2019), as presented in Figure 4-11. The pictures contained in the blue bracket correspond to the pay facies where most of the bitumen is hosted and are mainly composed of sand with a volume of shale (V_{sh}) lower than 30%. From the pictures, it can be observed that some areas within the reservoir have significant heterogeneity, and these heterogeneities control the growth of the steam chamber and the recovery percent of bitumen. Also, due to the low permeability of shale, there will not be fluid flow through areas with a high amount of shale. Therefore, the primary heat transfer mechanism will be conduction. This heat transfer mechanism will be determinant when measuring temperature distribution since heating the reservoir by conduction takes a longer time than convection (Su, 2016).

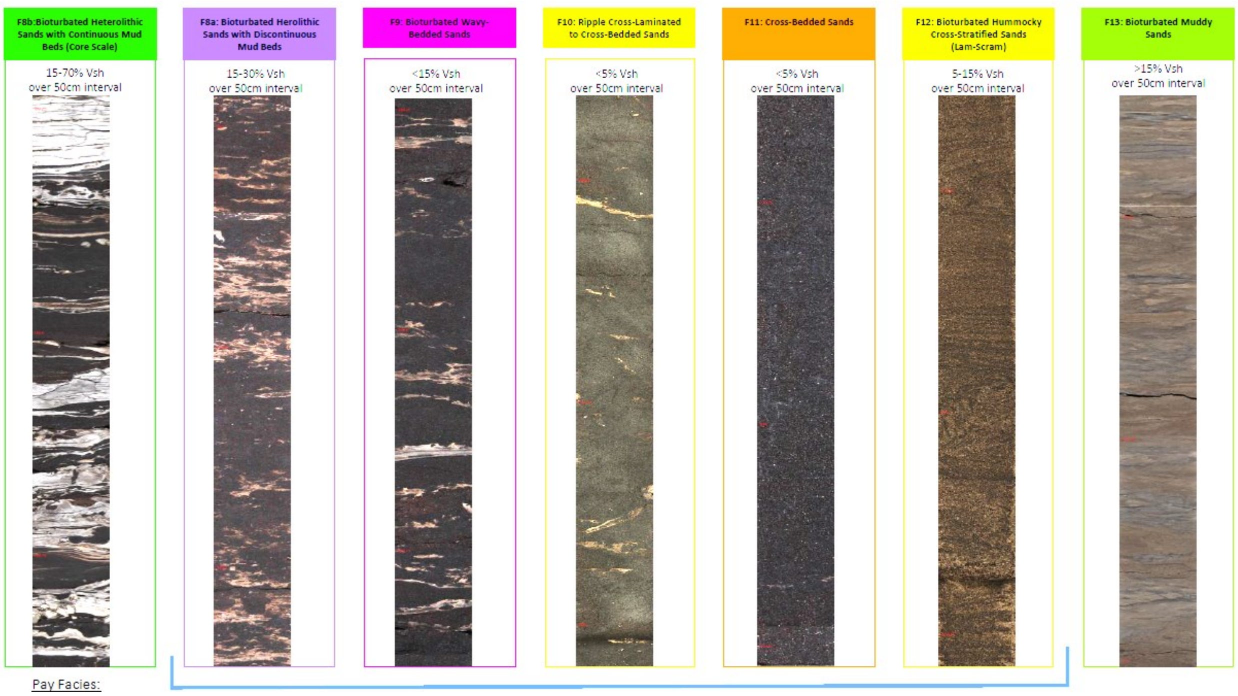


Figure 4-11 Pictures of facies that have been identified within the reservoir. Taken from (PetroChina Canada, 2019)

4.3.3 Geomechanical model

The geomechanical simulation requires inputs such as pore pressure, stress state, constitutive model, and elastic, plastic, and strength parameters. Once this information is gathered, the model can be populated, followed by a dynamic simulation to simulate operating conditions. Pore pressure and stress state are estimated based on observation of the area, while geomechanical properties are obtained from laboratory experiments. In this study case, public reports and scientific literature is used to populate the geomechanical model grid.

4.3.3.1 Pore pressure and stress state

The area's pore pressure and stress state are obtained from observations and field investigation techniques such as piezometers, mini-frac tests, and regional tectonics analysis. Due to the depth of the reservoir in Athabasca oil sands, there is a complex hydrogeological setting, and the reservoir has been connected over the years to underground aquifers, streams, and rivers, as was stated in a public report performed at the evaluation stage of the area (Hackbarth & Natasa, 1979).

Pore pressure data obtained at the McMurray formation corresponds to a sub-pressurized formation with measurements of 200 kPa at the top of the formation followed by a hydrostatic gradient to the base of the formation, as presented in Figure 4-12. This data suggests that the reservoir has been at drained conditions over geological time. However, current information shows good reservoir containment, in the area bitumen itself has acted as a seal for many parts of the reservoir since at reservoir temperature, it is immobile and reduces the effective permeability to water (Bachu, Underschultz, & Cotterill, 1993).

In the MRCP area, a low-pressure cap of gas has been identified at the top of the reservoir, specifically at high structural points. Measurements show pressures as low as 50 kPa at the cap gas, as illustrated with the red dot in Figure 4-12. The figure also shows a low-pressure "lean zone" which corresponds to high water saturation zones at the reservoir's top. For some projects of the area, the presence of a lean zone represents a challenge for SAGD since they can become thief zones where steam can flow and dissipate easily. This results in heating the initial reservoir water instead of bitumen, which significantly reduces the recovery factor (Xu, 2015). Also, lean zones play a crucial role in monitoring since they affect steam chamber growth. Figure 4-12 also includes some measurements taken at Wabiskaw sand (yellow dots). Wabiskaw Sand is identified as a water and gas saturated sand with high permeability. The difference in measurements suggests that Wabiskaw and McMurray are not hydraulically connected.

Pore pressure profile in the layers above the reservoir and Wabiskaw sand follows the stratigraphy throughout Athabasca region where sand layers could act as drainage zones if laterally connected with riverbanks or regional aquifers reducing the pressure gradient from hydrostatic (Hackbarth & Natasa, 1979). For practical purposes, vertical continuity is assumed through all the upper layers of the model. The final pressure profile of the model from the ground surface to the Devonian carbonates is presented in Figure 4-14

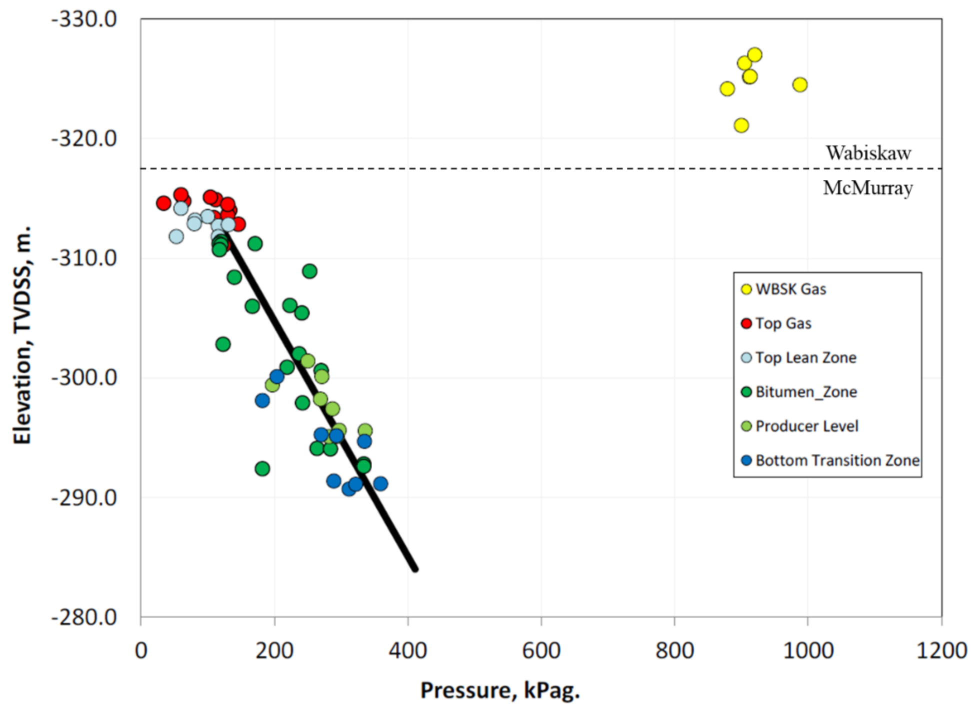


Figure 4-12 Initial pressure measurements at McMurray and Wabiskaw Formations. Modified from (Petrochina Canada, 2018)

The current stress regime of the Athabasca area is the result of different geological processes that have occurred in the last 100 million years. Initially, the area was influenced by tectonic forces that caused the orogeny of the Canadian Rockies. The azimuth of the area's maximum horizontal stress is still influenced by this process resulting in a NE-SW strike. Later, in the last 100 thousand years, the loading and unloading cycles caused by continental glaciations altered the stresses of the area. During the glaciation eras, the region was covered by an ice sheet that has been estimated to be as thick as 3km, increasing the vertical stress significantly. This increment in the vertical stress also resulted in increments of the horizontal stresses. Once the ice melted, around 12000 years ago, the vertical stress was removed while the horizontal stresses remain in the area leading to overconsolidation and a thrust faulting regime ($\sigma_H > \sigma_h > \sigma_v$) (Bell & Grasby, 2012b; Bell, Price, & McLellan, 1994; Maurice B. Dusseault, 1977a).

The vertical stress at any point in the subsurface is caused by the weight of all the material above and can be calculated by integrating the total density log of the formations using equation 4-1. The calculated vertical stress for the model is presented in Figure 4-13.

$$\sigma_v = \int_0^D g\rho_{(z)}dz, \qquad 4\text{-}1$$

where:

σ_v: Vertical stress

g: Gravity

$\rho_{(z)}$: Density log

D: Depth

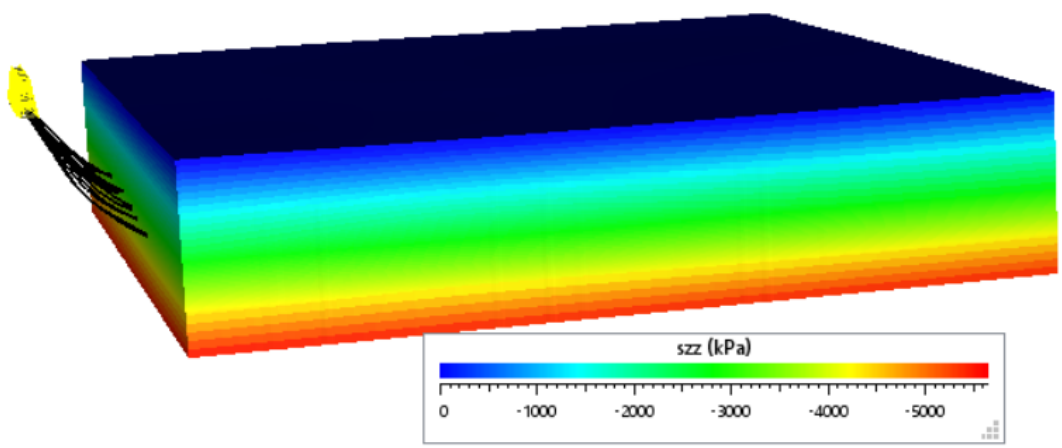


Figure 4-13 Calculated vertical stress at Pad AE model.

The least principal stress is obtained from minifrac tests. In this case, the operator of the project has performed minifrac tests in four different wells in the project area. Three wells were tested at different formations, while one well was only tested in the McMurray sand. The results of all the tests are summarized in Table 4-2, and these results are consistent for Clearwater and McMurray formations. On the other hand, there is some variability in the Wabiskaw formation, which can be caused by the heterogeneity of the formation and the fact that the formation has sandy and clayey zones. The tested zones are not specified in the public data.

The gradient difference between sandy and clayey formation is originated from the difference in the mechanical properties, especially Poisson's ratio, which governs the ratio of horizontal and vertical stress. Finally, the average fracture gradients reported for each formation were used for populating minimum stress in the grid. Thus, a gradient of 16.2 kPa/m and 21.5 kPa/m was used for reservoir and caprock, respectively.

Table 4-2 Fracture gradient obtained from minifrac tests at different formations in MacKay River Commercial Project.

Well	Formation	Fracture Gradient (kPa/m)
100/04-23-90-14W4	McMurray	16.7
1AA/06-07-90-13W4	Clearwater	21.5
	McMurray	14.9
1AA/14-28-90-14W4	Wabiskaw	21.3
	Clearwater	20.6
	McMurray	16.9
100/03-14-090-15W4	Wabiskaw	18.8
	Clearwater	22.3

Finally, the maximum horizontal stress, which is one of the most challenging processes in geomechanical modeling, was estimated. There is no method to measure it directly and most of the methodologies used in the industry are based on wellbore stability observations or special logging technologies such as dipole sonic. For this model, the maximum horizontal stress is obtained from available literature of the area. Joslyn's surface steam release report stated a value of a stress ratio of 1.4 that can be replaced in equation 4-2 to determine maximum horizontal stress. The values populated in the model are presented in Figure 4-14, including pore pressure, total stresses, and effective stress profiles

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$$s_o = {\sigma'_H}/{\sigma'_v} \quad \text{4-2}$$

Solving for σ_H

$$\sigma_H = (\sigma_v - p_p) * s_o + p_p \quad \text{4-3}$$

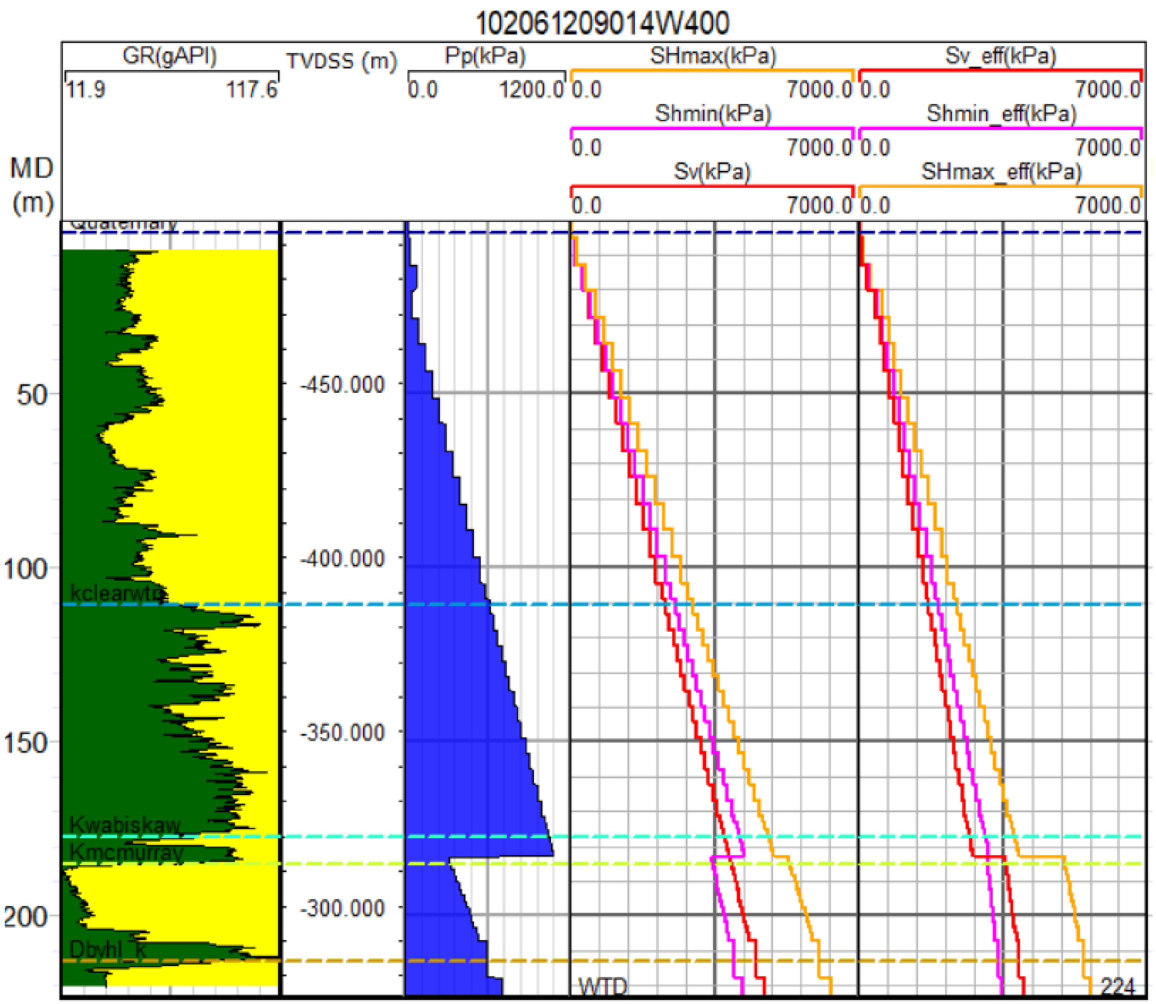


Figure 4-14 Pore pressure, total stress and effective stress profiles used in the model.

4.3.3.2 Geomechanical properties

The geomechanical model includes different kinds of material such as glacier till, clay-shale, silt, sand, and carbonates. Each material exhibits a different response to stresses and temperature; therefore, a constitutive model is assigned to each material based on previous experimental works. Three different kinds of material are used in these zones of the model to include heterogeneity in the caprock and the reservoir. All the constitutive models or mechanical groups used in the geomechanical model are summarized in Table 4-3.

Table 4-3 Definitions of different mechanical groups used in the geomechanical model.

Formation	Facie	Mech_group
Till	---	Till (1)
Clearwater	Clay	Clay-shale (2)
	Sand	Silty clay(3)
Wabiskaw	Clay	Silty clay (3)
	Sand	Sand (4)
McMurray	Clay	Silty clay (3)
	Sand	Sand (4)
Devonian	---	Devonian (5)

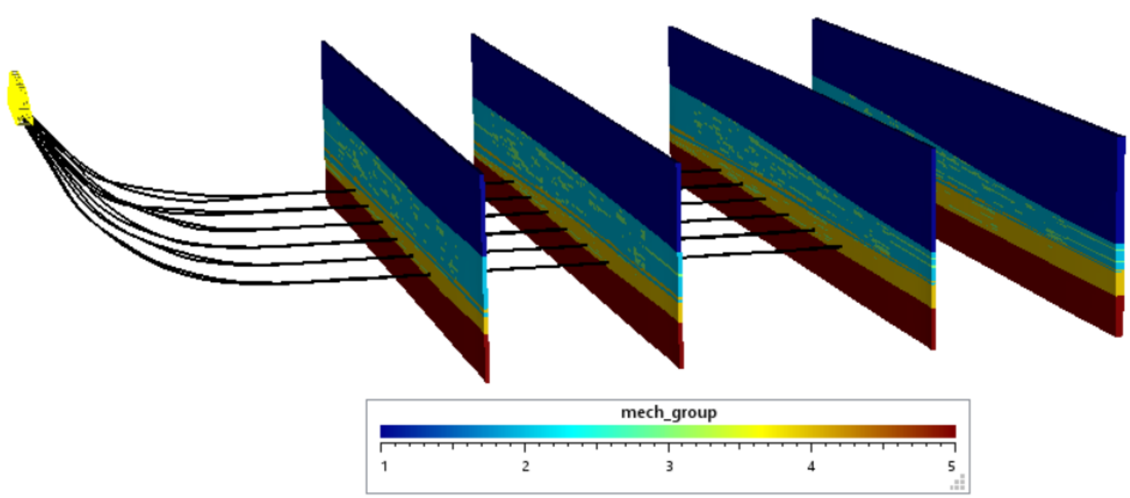


Figure 4-15 Geomechanical groups in Pad AE model at different cross-setions

For each mechanical group, it is required to define a constitutive model and the necessary parameters to simulate the selected model. The geomechanical properties were obtained from previous research performed mainly at the University of Alberta. The constitutive model is also selected based on experimental results of earlier works. Initially, the geomechanical studies of the area were mainly focused on the McMurray formation to assure stability of the slopes in the open pits (Dusseault, 1977b). Later, while Butler was developing the theory and the preliminary experiments for SAGD (Butler et al., 1981), some questions regarding the material response to temperature and pressure arose. Different authors' experimental results suggest that McMurray formation exhibits a stress-dependent geomechanical behavior (Agar, 1984; Chalaturnyk, 1995; Kosar, 1989; Oldakowski, 1994), which requires geomechanical parameters as a function of stress. Additionally, experimental results also show that McMurray samples describe a strain-softening behavior in the plastic region. This behavior is included in this research's geomechanical simulation to obtain a model as realistic as possible. For the stress-dependent Young's modulus, equation 4-4 is used, which was initially proposed by Chalaturnyk (R. J. Chalaturnyk, 1995).

$$E = 343 * \sigma'^{0.875}_{p} \qquad \text{4-4}$$

where

$$\sigma'_p = \frac{\sigma_1 + \sigma_2 + \sigma_3}{3} - p_p \qquad \text{4-5}$$

For Clearwater clay-shale, a linear correlation (equation 4-6) proposed by Oldakowski (K Oldakowski, Sawatzky, & Alvarez, 2016) and obtained from laboratory tests is used in this research.

$$E = 80 * \sigma'_3 + 23.6 \qquad \text{4-6}$$

Finally, for the silty clay mechanical group, a linear correlation fitted to experimental data proposed by Zadeh (Zadeh, 2016) is presented in equation 4-7.

$$E = 58.4 * \sigma'_p \qquad 4\text{-}7$$

Table 4-4 Geomechanical properties used in Pad AE model

mech_group	Till	Clay-shale	Silt	Sand	Devonian
Constitutive model	Elastic	M-C	M-C	Strain-softening	M-C
Biot's coefficient	1	1	1	1	1
Thermal expansion coefficient (10^6 1/°C)	0	0.5	2	2.4	1
Young's modulus (MPa)	200	Eq 4-4	Eq 4-6	Eq 4-7	2000
Poisson's ratio	0.3	0.3	0.35	0.25	0.25
Friction angle (°)	---	30	35	Table 4-5	45
Cohesion (MPa)	---	0.24	0.1	0	5
Dilation angle (°)	---	10	12	Table 4-5	20
Tensile strength (MPa)	---	0.1	0.1	0	0.4

Table 4-5 Strain-softening tables used for McMurray Formation

Plastic strain	Friction angle (°)	Dilation angle (°)
0.00	45.0	20.0
0.005	45.8	21.0

0.010	46.5	22.0
0.015	47.7	24.0
0.020	48.0	22.0
0.025	48.3	22.0
0.030	47.5	20.0
0.040	46.5	18.0
0.050	44.0	16.0
0.060	43.0	14.0
0.070	42.0	12.0
0.080	41.0	10.0
0.090	40.0	9.0

4.3.4 Flow model

Petrophysical properties required for flow and thermal simulation in McMurray and Wabiskaw formations are populated in the grid using geostatistical analysis. For this, information from well logging as porosity and resistivity is used. Log data was calibrated using core data when available. Geostatistical analysis was performed for porosity, water saturation, and permeability using both log data and core data in the MacKay River Project area. In total, ten realizations were obtained for each parameter from the geostatistical analysis.

The realizations selection was based on original oil in place (OOIP) to confirm that the model is representative of the real data in the area. Considering the purpose of the model, realization ranking is not necessary since the objective is to identify the impact of heterogeneity on the monitoring results. The selected realization is assumed to be a "true" static model that can be used to evaluate the response of heterogeneous subsurface to SAGD operations.

Figure 4-16 shows the horizontal permeability selected for the simulation. It includes McMurray, Wabiskaw Shale and Wabiskaw Sand formations. It also includes the mud bodies or clay within the reservoir, which are represented by low permeability values. For the formations outside the reservoir, constant values for petrophysical properties were assumed, as is summarized in Table 4-6.

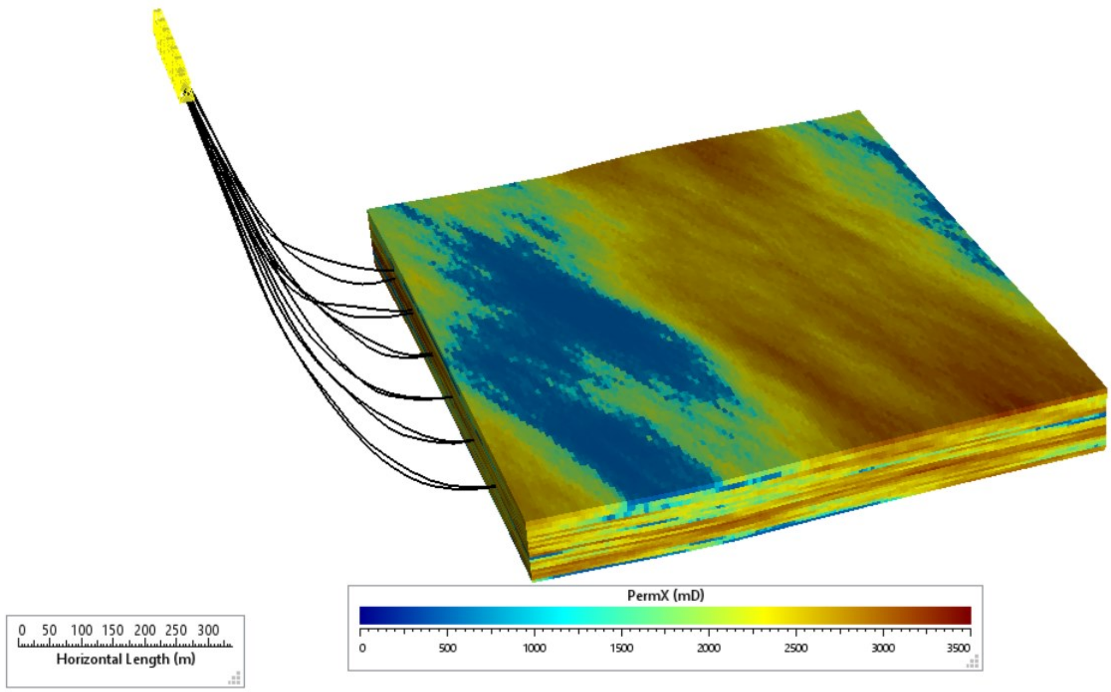


Figure 4-16 Horizontal permeability distribution of flow model for Pad AE.

Table 4-6 Petrophysical properties of geomechanical model.

Formation	porosity	k_x (mD)	k_z (mD)	S_w
Till	0.3	50	10	1
Clearwater	0.31	0.001	0.0002	1
Wabiskaw sand	geostats	700	100	geostats
Wabiskaw clay	geostats	1	0.2	geostats
McMurray	geostats	geostats	geostats	geostats
Devonian	0.4	50	10	1

CHAPTER 5 PREDICTION OF MONITORING PARAMETERS FOR SAGD USING NUMERICAL SIMULATION.

5.1 Introduction

Predicting the geomechanical response of the subsurface during SAGD is crucial to planning and implementing an adequate monitoring program. Geological heterogeneity in the subsurface plays a key role in monitoring response since it governs geomechanical and flow behavior within the reservoir and surrounding formations. For instance, mud bodies within the reservoir affect the growth of the steam chamber and heat transfer mechanisms while also affecting the deformation because they display different constitutive behavior. Including this information, when possible, helps to identify the most appropriate instruments and their location. On the other hand, monitoring results help improve understanding of subsurface heterogeneity and subsurface structure, reducing response uncertainty

In this chapter, the responses of different measurable variables such as pressure, temperature, and displacement are evaluated for a defined heterogeneous case at normal operating conditions. The measurements are analyzed to identify the physical processes that cause such responses and their implication on reservoir and safety management. The results from homogeneous cases are also included in this study to identify the differences in monitoring caused by geological heterogeneity. Finally, a second scenario is evaluated at high-pressure conditions to determine the response of monitoring at extreme conditions and even at failure. These results help design the appropriate monitoring to prevent failure or be used as an alarm in case of an unavoidable incident.

5.2 Dynamic model

Dynamic modeling refers to the simulation of the thermal process itself. Once the static model is constructed, fluid flow and deformation simulation can be performed to reproduce different operating conditions. For this research, a coupling platform that has been developed at the University of Alberta is used. The coupling platform allows to couple flow two commercial simulators, STARS and FLAC 3D.

5.2.1 [RG]^2 Coupling platform

At the University of Alberta, the Reservoir Geomechanics Research Group [RG]^2 has developed a tool that couples two commercial softwares to run thermal-flow-geomechanical simulations, STARS and FLAC 3D. STARS is a widely used numerical reservoir simulator for thermal recovery that solves the continuity and energy equations in porous media using the finite differences method. FLAC3D is also a renowned numerical simulator for rock mechanics applications. FLAC3D solves Cauchy's equation of motion for a continuum also using finite difference discretization. In general, while STARS solves the continuity equation without accounting for the geomechanical effect in the reservoir properties, FLAC3D solves the equilibrium equations without accounting for flow and fluid phase relationships in the pore fluids (Deisman, Chalaturnyk, Ivars, & Geomechanik, 2009). Subsequently, for processes that involve complex physics, such as thermal recovery, coupled analysis becomes a requirement. The workflow followed for the platform is illustrated in Figure 5-1.

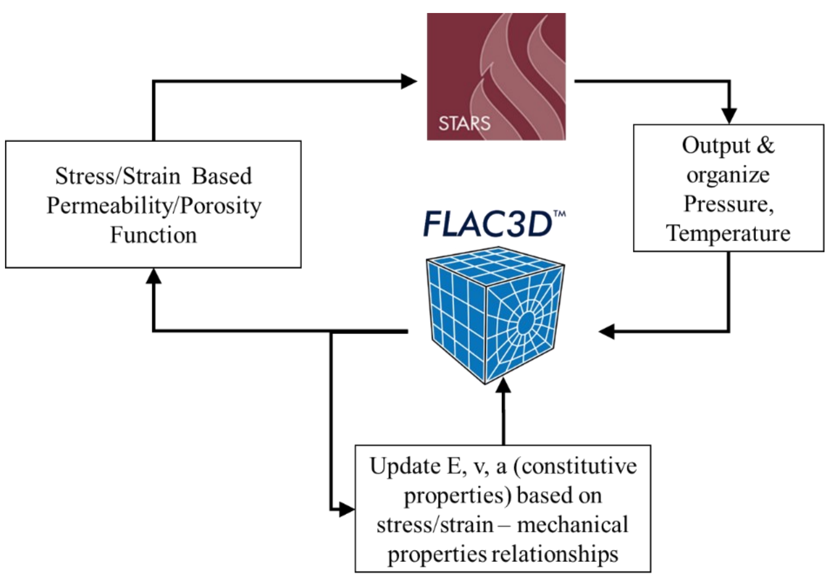


Figure 5-1 Reservoir Geomechanics Research Group coupling platform. Taken from Deisman (2017)

5.2.1.1 One-way coupling

One-way coupling is used to evaluate the impact of changes in deformation resulted from pressure and temperature disturbance in the reservoir. Pressure and temperature distributions within the reservoir are calculated by flow simulator and are exported to assess their effect on the deformation of the reservoir and surrounding formations using a geomechanical simulator. There is no feedback from the geomechanical behavior in one-way coupling to update the petrophysical properties; therefore, fluid flow is not affected by deformation directly. The RG^2 platform helps to import the pressure (P), temperature (T), and saturation (S) distribution calculated in STARS into FALC3D (Figure 5-2) at specific time steps. With the distributions, FLAC3D runs until equilibrium is achieved for the specific conditions. Once FLAC3D finishes the simulation, variables such as stress (σ), strain (ε), and displacement (δ) can be analyzed for all the blocks of the model.

Even though one-way coupling does not capture all the physics related to steam injection, given that petrophysical properties are not updated, it has been proven to be an efficient solution to analyze geomechanics response when poromechanics effects are not be captured (Prevost, 2013). The main advantage of one-way coupling is that it demands fewer computation resources than two-way coupling since geomechanics does not alter the flow simulation. For many applications, such as surface displacement and caprock integrity, the one-way coupling can be enough to evaluate thermal recovery's geomechanical response when the poromechanics effect is not analyzed in detail. The main limitation is that fluid flow is not affected by the geomechanical behaviour of the sand, which usually results in permeability enhancement and, subsequently, production increase in SAGD operations, as noted by Chalaturnyk (1995).

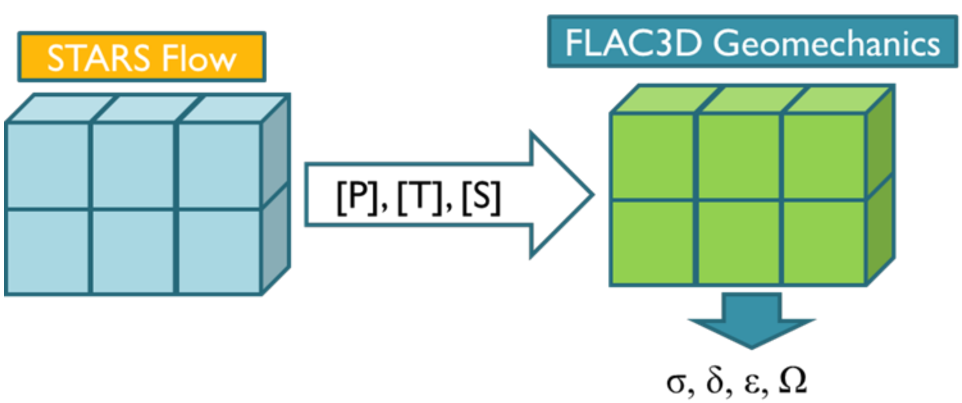


Figure 5-2 One-way coupling simulation scheme (Deisman ,2017)

5.2.1.2 Two-way coupling

Two-way or sequential coupling uses the calculated pressure, temperature, and saturation within the reservoir obtained from a flow simulator to evaluate the geomechanical response. Subsequently, reservoir properties as porosity and permeability are updated based on deformation and failure condition obtained from a geomechanical simulator. Finally, the updated permeability and porosity are imported into the flow simulator to run the next time step (Figure 5-3). The coupling times are usually selected based on times of interest. They should be as continuous as possible when sudden changes occur in the process, such as the start of injection, to ensure the numerical stability of the model. Even though two-way coupling captures more physics than one-way coupling, it can be expensive for computation. It usually requires more powerful hardware and simulation times are longer given the processes updates that run through the coupling.

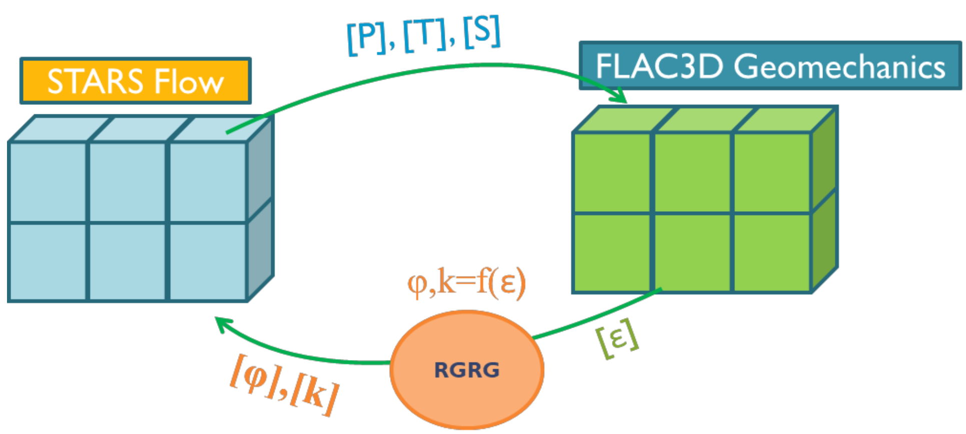


Figure 5-3 Sequential coupling simulation scheme (Deisman, 2017)

5.2.2 Boundary conditions

Boundary conditions are an essential part of numerical simulations. For flow/geomechanical simulations, two different boundary conditions should be defined, flow/thermal and deformation boundaries, as illustrated in Figure 5-4. In this case, the flow/thermal boundary condition is set at the edges of the flow model that is inside the geomechanical model, as explained in 4.3.1. The flow boundary condition is assumed to be no flow condition for all boundaries in the current model. This boundary condition implies that the reservoir is closed, and no flow or heat transfer is allowed in or out of the model.

On the other hand, deformation boundary conditions are defined as no displacement for all the faces except the top, which corresponds to the ground surface, where deformation is allowed in all directions. This boundary condition assumes that the model is big enough to have no displacement disturbance at the model's boundary. Thus, boundary conditions for both flow and deformation are representative of field conditions for SAGD.

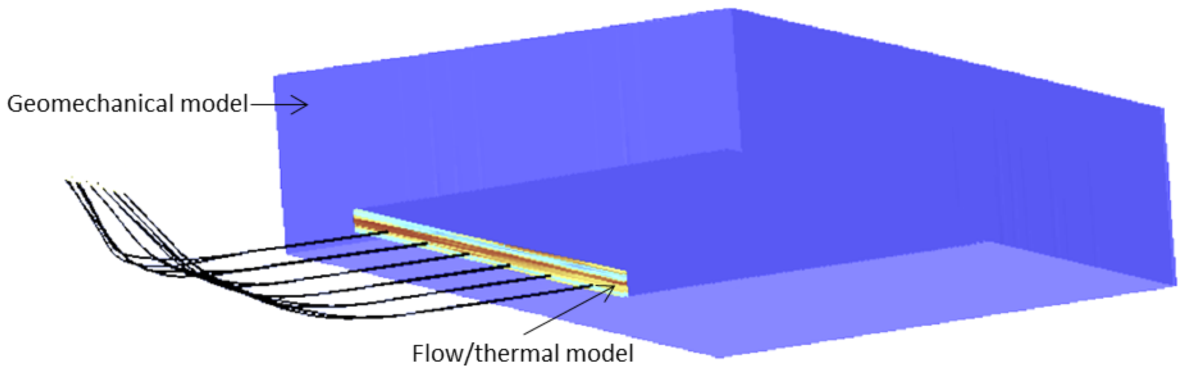


Figure 5-4 Flow and geomechanical boundary conditions

The objective of thermal recovery is to lower the bitumen viscosity to become mobile in the reservoir. Bitumen viscosity and temperature relationship is typically exponential, as shown in Figure 5-5, a typical curve for bitumen in Athabasca oil sands (Hepler and Hsi, 1989). The temperature of steam injected in the reservoir depends on the injection pressure and steam quality. Usually, temperatures ranging from 180°C to 150°C are used depending on the different factors as the depth of the reservoir and the corresponding operating pressure. This range reduces the viscosity to values lower than 20 cP, facilitating flow through the reservoir and wellbore.

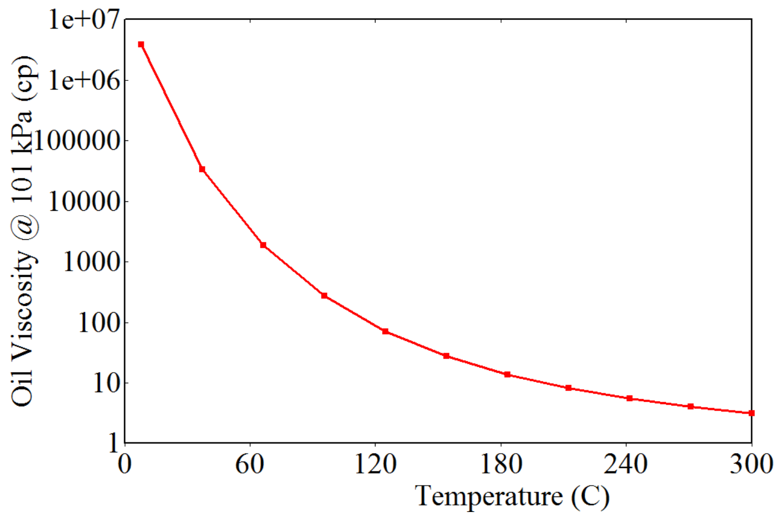


Figure 5-5 Bitumen viscosity vs. temperature relationship used in simulation

5.3 Operating conditions

Initially, the wells are in the circulation phase for five months to generate hydraulic communication between injectors and producers. During this phase, steam is injected and produced simultaneously to heat the wellbore vicinity and reduce the bitumen's viscosity.

This chapter considers two different operating conditions for the SAGD phase; the first one maintains the injection pressure of all injector wells below MOP and represents this project's planned operating conditions. The second one corresponds to a case where injection pressure is maintained at a pressure equal to minimum in-situ stress at the base of the caprock, as presented in Figure 5-6. In Figure 5-6 a) injection pressure is reduced over time to mimic the actual conditions planned for the project. The simulation is carried out for ten years to capture the response of monitoring parameters at the initial and late stages of the project.

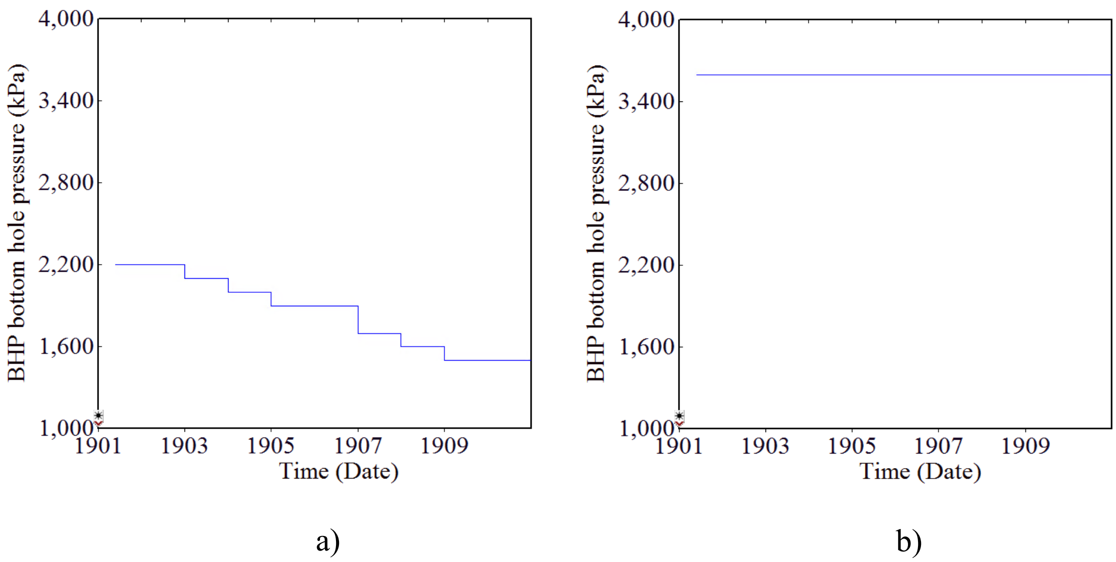


Figure 5-6 Injection pressure during SAGD. a) pressure below MOP. b) Pressure equal to minimum in-situ stress

Producer wells operate using two different constraints, minimum bottom hole pressure (BHP) and maximum steam rate or steam trap. The minimum bottom hole pressure was set at 750 kPa, and a maximum steam rate was set at 5 m^3/day for all simulations analyzed in this chapter. The second constraint is commonly used in the field to ensure no breakthrough from the injector to the producer occurs keeping the steam in the reservoir to heat the bitumen. High vertical permeability in the oil sands usually implies low-pressure drops between the injector and the producer; therefore, the steam rate controls the operating pressure at the producer well.

5.4 SAGD simulation results below MOP

5.4.1 Steam chambers geometry from simulation results

When analyzing SAGD process, one of the key factors to evaluate is the shape of the steam chamber. Chamber's shape has an impact on both production and geomechanical response. The shape is mainly controlled by geological heterogeneity and initial fluid saturations. Figure 5-7 illustrates the steam chambers for all the six well-pairs of the pad at different times. The chambers initially grow independently, followed by chambers coalescence when two or more chambers start growing together. The coalescence time depends on the thickness of the pay zone and vertical and horizontal permeability. Results show that the steam chamber at Well-pair 5 grows faster than the other well-pairs. This behavior can be explained by the good reservoir quality around Well-pair 5 and the absence of mud bodies around it. Coalescence between Well-pairs 3, 4, and 5 steam chambers occurs after four years. After seven years, most cambers coalescence except Well-pair 1 and 2, where the reservoir has more heterogeneity and permeability is lower.

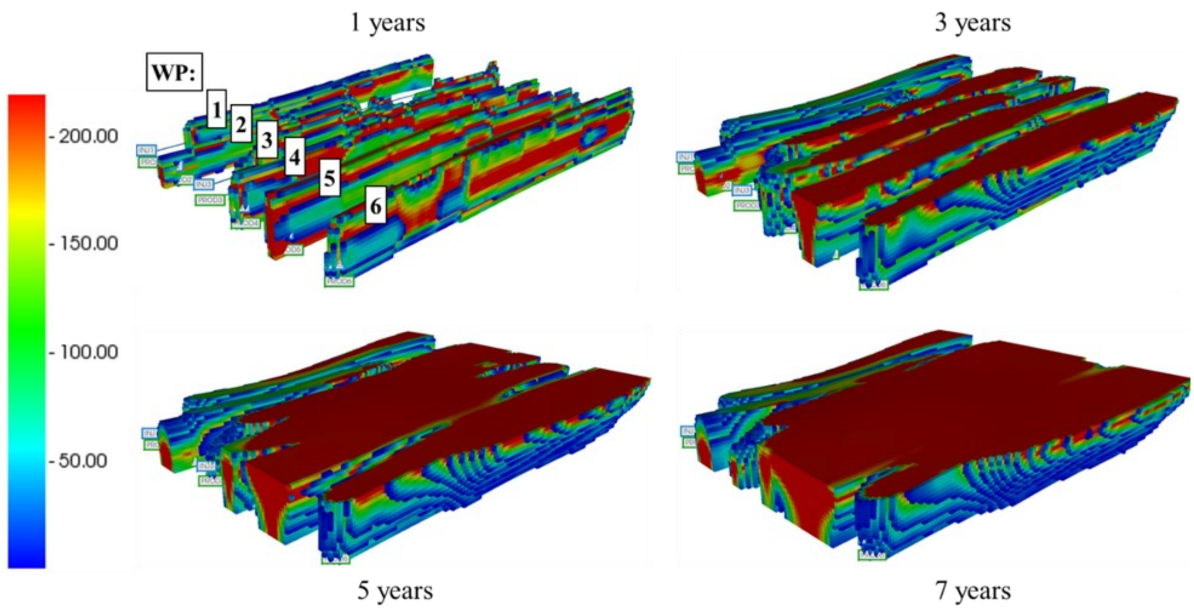


Figure 5-7 3D Steam chambers geometry from thermal reservoir simulation

Moreover, the steam chamber growth is not homogeneous in the horizontal given the geological heterogeneity. For instance, at Well-pair 1, there is no steam chamber development at the heel of the wells even after seven years of SAGD. The lack of steam chamber development is caused by the low permeability of the reservoir at his location, as illustrated in Figure 5-8.

Steam chamber growth can be monitored using fiber optics or any other temperature sensor within the reservoir. Additionally, the temperature can be monitored along the horizontal well to evaluate the wells' conformance and identify any preferential flow pathway for steam within the reservoir.

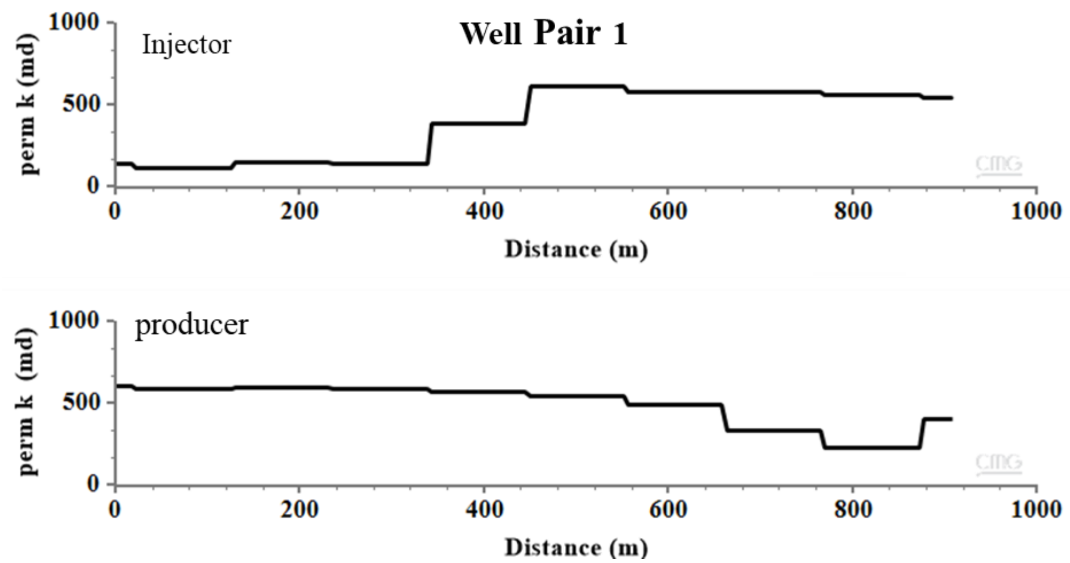


Figure 5-8 vertical permeability of blocks intersected by Well-pair 1.

5.4.2 Stress path at the top of the reservoir

Stress path in the reservoir has been extensively studied before (Benham et al., 2018; Chalaturnyk, 1995; Tahar, 2012; Zhang, 2019). Numerical simulations and experiments show the importance of understanding the reservoir's permeability and productivity enhancement by understanding the followed stress path. Furthermore, understanding the change in stress, displacement, and failure is crucial to plan reservoir containment monitoring strategies and understand monitoring results.

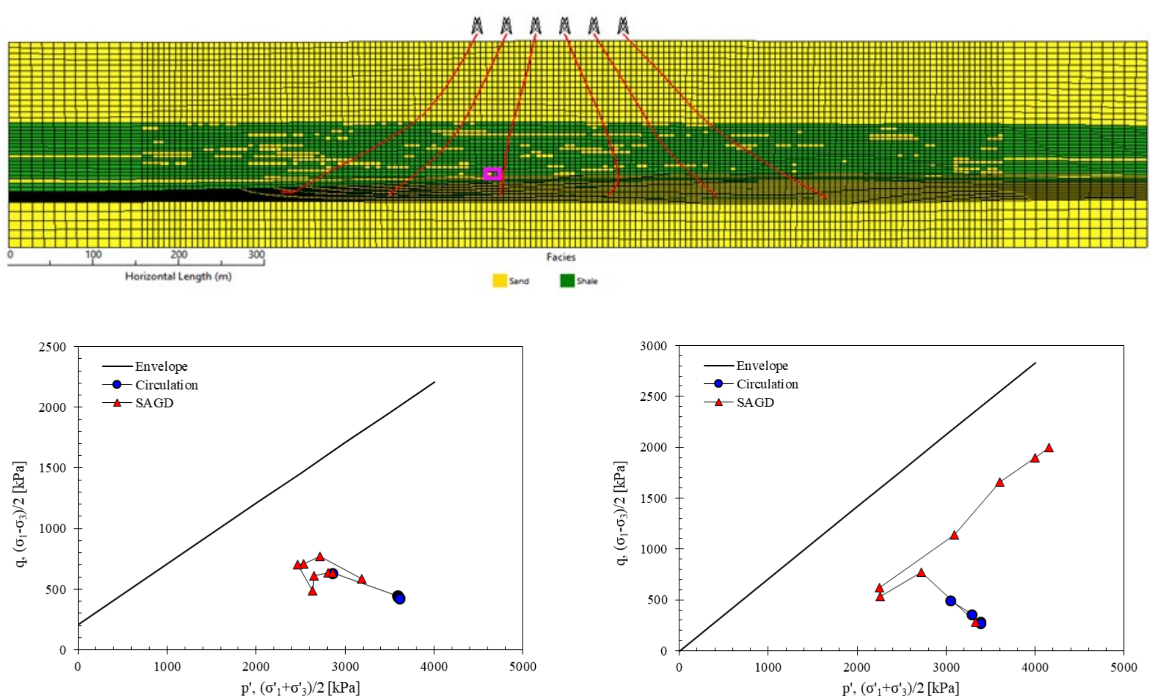
According to the systematic approach proposed in CHAPTER 3, predicting the mechanisms that control behavior is a key step for designing monitoring programs. In this case, the stress path for the formations that overlay the pay zone is analyzed to investigate the geomechanical processes that take place at these points during SAGD.

The stress path can vary significantly depending on the location to be analyzed. Even within the reservoir, the material follows different stress paths depending on the position from the well-pairs, according to Zhang (2019). At the caprock, the stress path can be significantly different due to the geometry of the steam chambers and the associated deformation in the upper layers. Therefore, the stress path at the middle of the pad is analyzed for Wabiskaw and Clearwater formations to simplify the analysis.

For Wabiskaw formation, two different materials were considered, sand and clay, according to gamma-ray logs. Wabiskaw Sand is commonly used for reservoir containment monitoring in the Athabasca area, given the capacity to transmit pressure. In contrast, Wabiskaw shale, a layer immediately above the reservoir, is very tight.

Figure 5-9 a) illustrates the stress path followed by the Wabiskaw Shale. It remains far from the failure envelope at the operating conditions, with some impact of pressure and temperature at the SAGD phase. Once injection pressure is dropped, the stress path approaches its departing point. In this layer, the simulation results exhibit a significant influence of thermal-induced pore pressure since it is directly exposed to the high temperature of the steam chamber. This behavior is explained in more detail later in this chapter. This layer is also exposed to large deformation and stress reduction due to the reservoir volumetric strain.

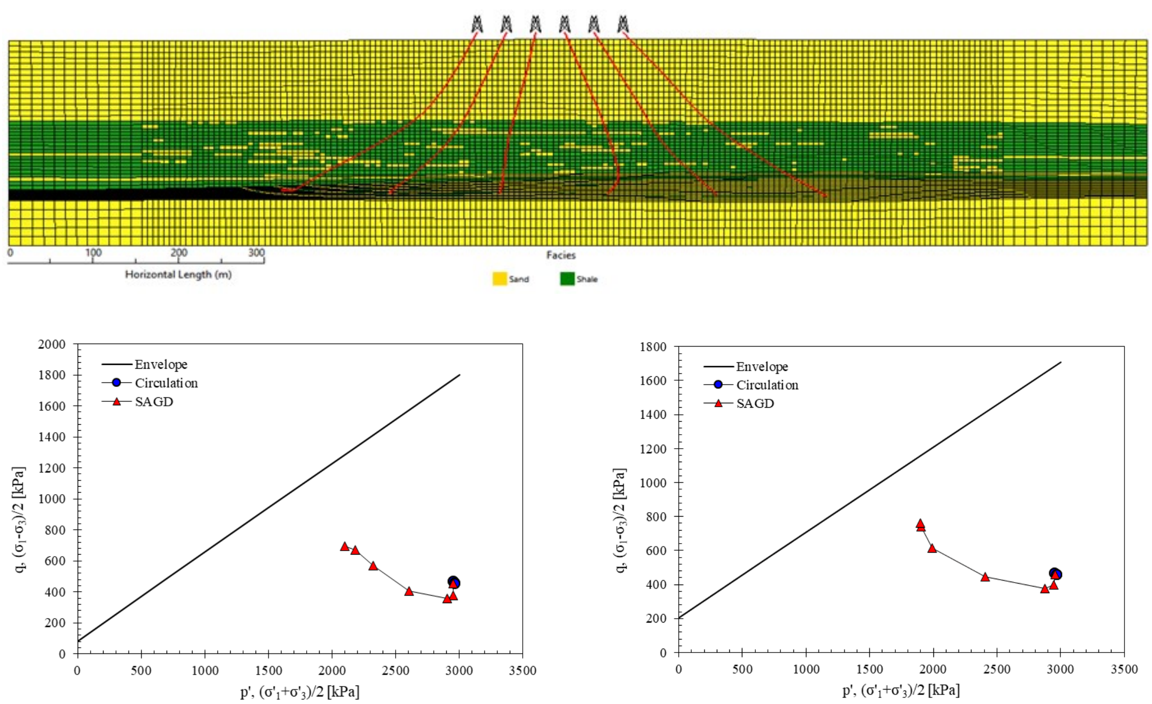
Wabiskaw Sand exhibits a similar behavior at the beginning of the process when pore pressure increases by fluid injection and steam chambers start to grow. Then, once the temperature changes, there is a noticeable change in the stress path. This formation gets pressurized due to thermal-induced pore pressure caused by conductive heat transfer from the reservoir to the upper layers. The thermal expansion of the sand generates an increment in the maximum total stress that is reflected on the stress path.



a) b)

Figure 5-9 Stress path at two points in the middle of Pad in Wabiskaw formation. a) Wabiskaw Shale b) Wabiskaw Sand

The stress path in the Clearwater Formation is analyzed at the base of the formation that is exposed to conductive heat transfer and deformation from the underlying formations. The results show that the stress path remains constant during the circulation phase since the pressure and temperature disturbance concentrate in the vicinity of the well-pairs. Later, at the beginning of the SAGD phase, the volumetric deformation within the reservoir generates some stress changes in the upper layers and shear stress (q) decreases. Subsequently, when the reservoir is heated, volumetric strain in the reservoir induces total stress reduction in the caprock that is observed in the stress path for both silt and clay (Figure 5-10).



a) b)

Figure 5-10 Stress path at two points in the middle of Pad in Clearwater formation. a) Silt in Clearwater b)Shale in Clearwater

5.5 In-situ monitoring

Usually, instrumentation to measure pressure and temperature is used in vertical observation wells to monitor the steam chamber growth and possible flow to the upper layers. Often SAGD wells are also instrumented with temperature sensors along the horizontal section to guarantee that the steam is well distributed along the wells. Such instrumentation helps to identify steam breakthroughs that significantly reduce the sweep efficiency of the recovery processes. In addition, different technologies to measure deformation in-situ have been tested in SAGD projects, such as the extensometers and Gyros used in the UTF (see Figure 2-10).

Measurements can be taken at different depths, and some technologies such as fiber optic allow continuous measurements along a well. The measurements are affected by the distance to SAGD well-pairs and the heterogeneity between them. Figure 5-11 illustrates the heterogeneity in a cross-section in the middle of two SAGD Well-pairs. The model includes the Wabiskaw formation and part of the Clearwater to capture the temperature changes in these formations. The model also includes flow barriers such as mud channels within the reservoir to evaluate their impact on the response of monitored parameters. Figure 5-11 b) shows the vertical profile of oil saturation and horizontal permeability of Well 1 presented in the cross-section. It can be observed how the permeability of the model reduces significantly at the mud channel representing low permeability areas of the reservoir. The model includes the first meters of Clearwater caprock as well as Wabiskaw Sand and Wabiskaw Shale.

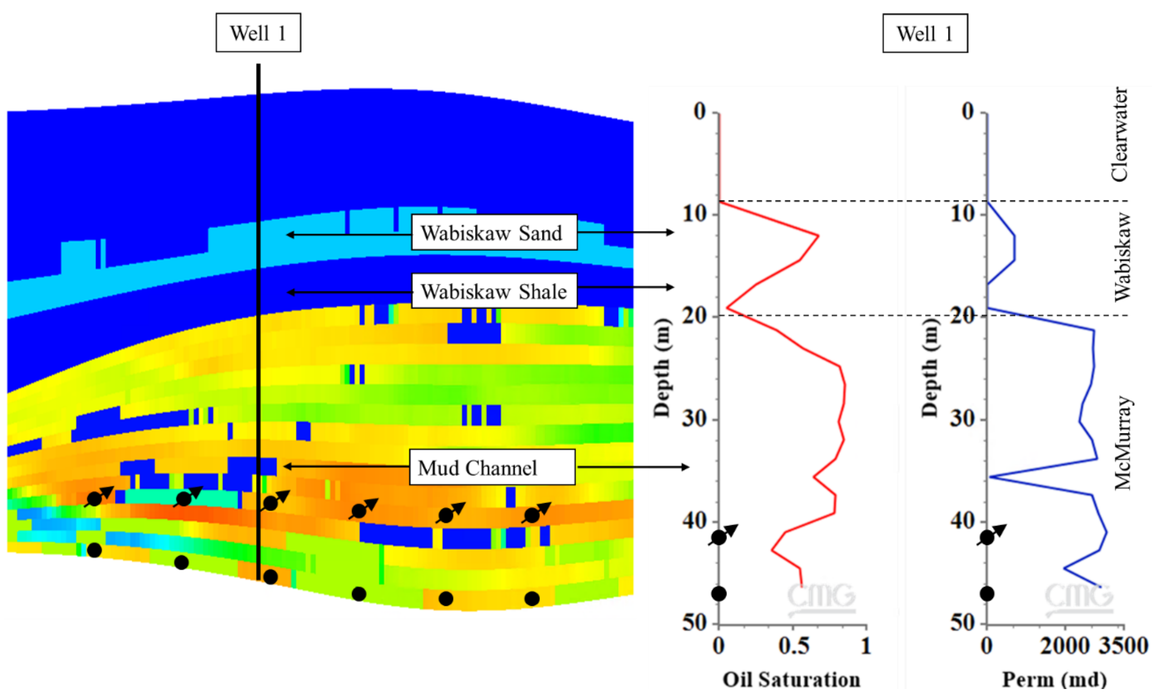


Figure 5-11 Permeability heterogeneity of a 2D cross-section for a heterogeneous model and the oil saturation and permeability profile at Well 1.

5.5.1 Temperature monitoring

Once the SAGD process initiates and steam is injected into the reservoir, different heat transfer mechanisms such as convection and conduction occur in the reservoir. These mechanisms will determine the geometry and size of the steam chamber and the associated bitumen recovery. Steam chamber geometry is dependent on petrophysical properties such as permeability and initial water saturation. In a homogeneous, bitumen-rich, theoretical case, the chamber will initially grow vertically, followed by lateral growth, increasing the drainage area, according to Butler(1981).

Interpreting chamber geometry from observation wells can be challenging since the readings show the temperature in a single line of the reservoir. In addition, interpretations become more demanding with time when steam chambers coalesce and analyzing the influence of each chamber can be challenging. Therefore, two different models are considered to understand the impact of reservoir heterogeneity on temperature readings: 1) a heterogeneous model including low permeability regions and 2) a homogeneous model with average properties calculated from the heterogeneous model.

Permeability profiles of both models are presented in Figure 5-12. The heterogeneous model includes a mud channel that acts as a flow barrier within the reservoir, as illustrated in Figure 5-11. Well-pair 1 is located just beside a SAGD Well-pair and is surrounded by mud bodies in the heterogeneous case. Temperature profiles presented in Figure 5-12 range from the circulation stage to six years of SAGD (red line). The two heat transfer mechanisms can be identified from the plots where convection is present at high permeability regions.

On the other hand, when hot steam meets a flow barrier, conductive heat transfer dominates the heat transfer. Thus, considerable heat transfer is predicted to the upper layers at a slow rate. The amount and rate of heat transferred to the upper formation will depend on the permeability and thickness of the Wabiskaw Shale formation, which acts as a primary seal at the top of the reservoir.

Similarly, flow barriers within the reservoir (mud channels) notably influence the measurements in an observation well. Figure 5-12 b) shows that the temperature increases faster below the flow barrier. Initially, there is some conductive behavior from the reservoir below the mud channel to the upper reservoir. The heterogeneous reservoir takes up to 6 six months of SAGD to read temperatures above 200°C at the Well-1 location, while for a homogeneous reservoir, it will take up to three years.

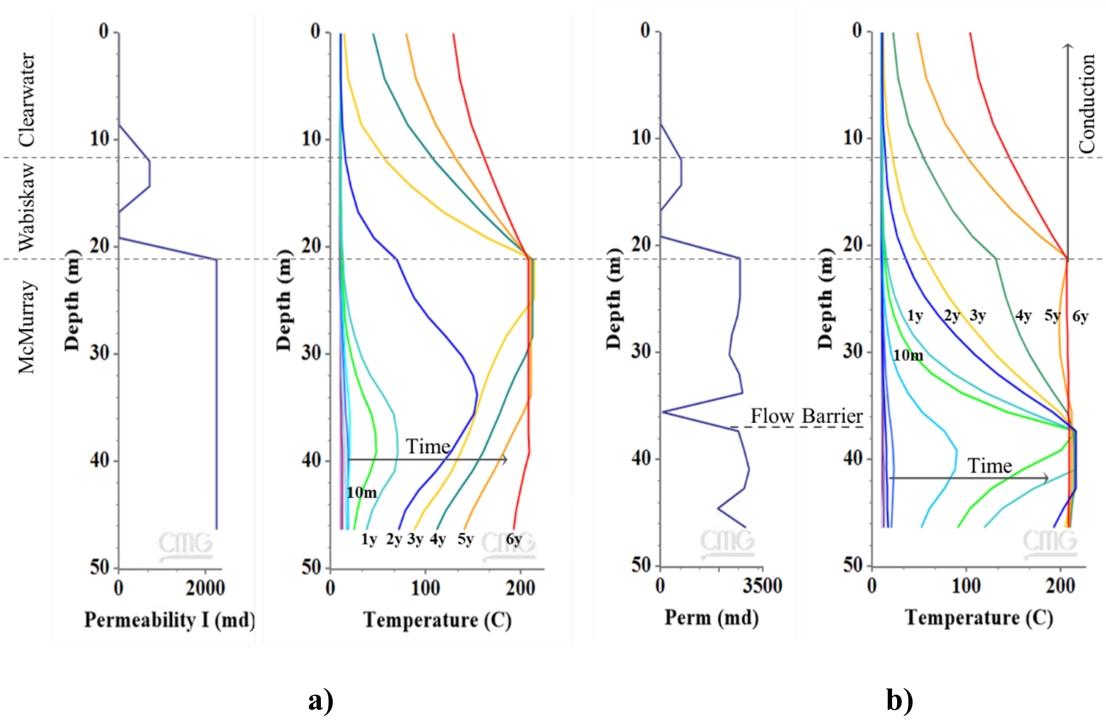


Figure 5-12 Predicted temperature profile at Well 1 for: a) homogeneous model and b) heterogeneous model

In contrast, the behavior of temperature readings assuming a homogeneous reservoir is governed by the vertical growth of the steam chamber. The steam chamber grows vertically and stops once Wabiskaw Shale is encountered. As soon as the barrier prevents vertical growth, the chamber starts extending laterally. Then it can be identified by the observation well at the top of the continuous pay-zone. As the steam chamber advances, more instruments vertically placed in the wellbore will measure the chamber temperature.

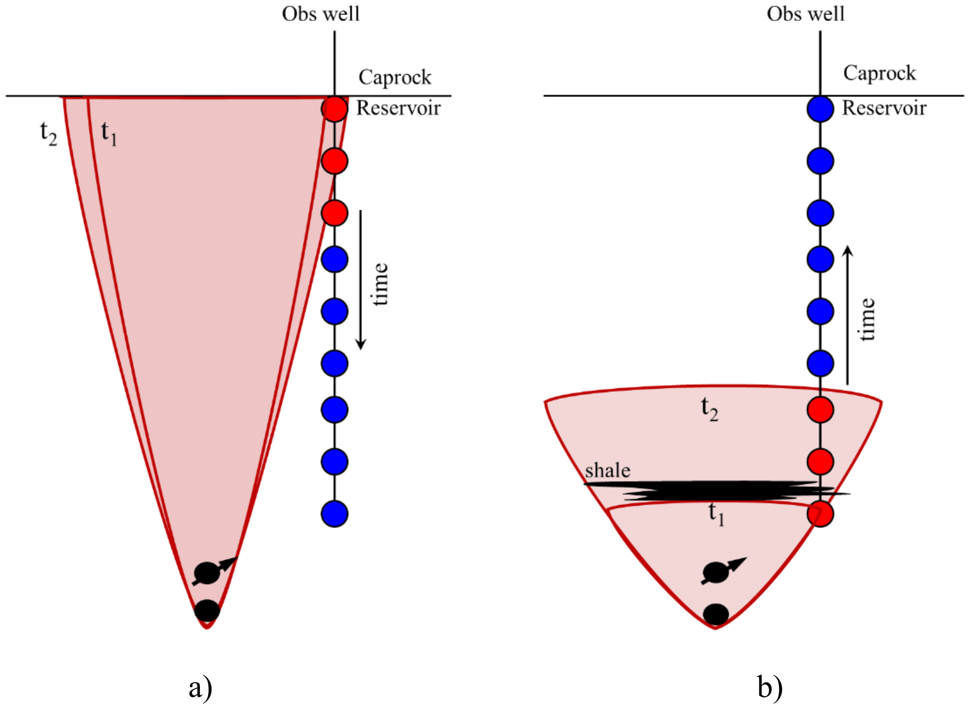


Figure 5-13 Temperature readings behavior at observation wells for a) homogeneous reservoir. b) heterogeneous reservoir

Figure 5-13 illustrates the temperature readings at a vertical observation well for a homogeneous and heterogeneous model. Figure 5-13 a) represents the measurements of an observation well in a homogeneous reservoir where the chamber will initially grow vertically, followed by lateral growth. Thus, the temperature at the observation well will initially be sensed at the top of the reservoir and will progress downwards through the different measurement depths. In contrast, if the reservoir is heterogeneous, the chamber will grow vertically until it reaches a non-permeable layer, from where the growth will be mainly lateral. Therefore, the readings at the observation well will start from the lower point and will advance upwards as the process continues, as illustrated in Figure 5-13 b).

Given the geology of the Athabasca area, it is common to find some permeable layers between the top of the reservoir and the bottom of the Clearwater caprock. These layers, whose names can change depending on the company and the project's location, are usually used to monitor flow and heat transfer from the reservoir to the upper layers. At MacKay River PetroChina, such layer is known as Wabiskaw Sand and is mainly composed of sand with good permeability. As explained before and according to real field data, conductive heat transfer from the reservoir to the upper layers is expected. Nevertheless, the amount and rate of heat are not constant at all locations of a project. Figure 5-14 shows the predicted behavior of temperature for Wabiskaw Sand at MRCP. Two different points are studied, 1) at the top of "Well-pair 1" and 2) at the top of "Well-pair 6". The results show that point 2 gets hotter than point 1 through all the simulation time.

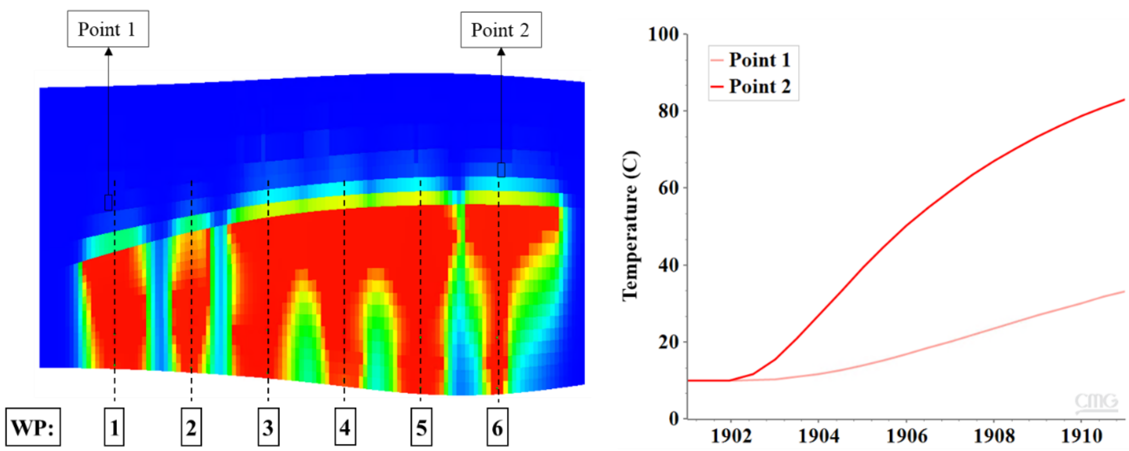


Figure 5-14 temperature behavior at the Wabiskaw sand monitoring zone.

Even though the reservoir is thinner at point 1, it takes longer to transfer heat from the steam chamber. The lower rate of transfer is the result of the presence of mud bodies within the reservoir that slows down the vertical growth of the steam chamber. On the other hand, at point 2, there is a high value of vertical permeability between the injector and the caprock with no presence of low permeability zones resulting in a faster heat transfer to the upper layers. These results demonstrate the importance of understanding heterogeneity within the reservoir to analyze monitoring results. Additionally, monitoring results could be handy to improve the geological interpretation of the formations.

According to the Systematic Approach proposed in CHAPTER 3, instruments should be located in areas where parameters are expected to be maximum. Given reservoir heterogeneity, the site's geology must be considered during planning monitoring programs to ensure the instruments are well-positioned. In addition, the influence of heterogeneity should be part of results interpretation to explain the subsurface behavior.

5.5.2 Pressure monitoring

5.5.2.1 Pressure monitoring within the reservoir

Pressure distribution in the reservoir during SAGD is highly dependent on the fluid saturation distribution. Zones with high water saturation or "lean zones" are commonly known as thief zones since they can take a lot of steam and dissipate the injected pressure (Xu, 2015), reducing recovery efficiency. However, even if the initial oil saturation is high in most real cases, some leak-off from the chamber to the unheated zones is expected. This flow causes the pressure front to go faster and further than the temperature front within the reservoir.

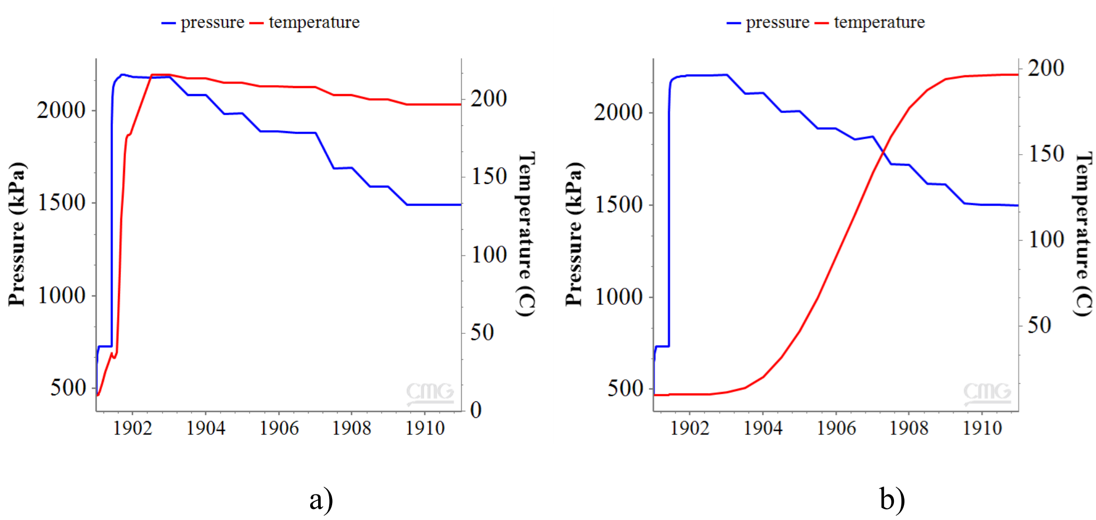


Figure 5-15 Pressure and temperature behavior at two different locations within the reservoir. **a)** a few meters away from a well-pair. **b)** At the middle of two well-pairs.

Figure 5-15 illustrates the pressure and temperature behavior of two different points at the same depth of the injector well for ten years. The first point presented in Figure 5-15 a) is located 10 meters away from the injector well, exhibiting simultaneous pressure and temperature changes and reflecting the changes in the injection program. In contrast, Figure 5-15 b) exhibits an immediate response in pressure that follows the injection conditions while temperature takes up to four years to start changing. This behavior suggests that pore pressure propagates more rapidly within the reservoir than temperature.

Consequently, installing only instruments to measure pressure as piezometers inside the reservoir might not help understand steam chamber architecture. Even though pressure leak-off depends on initial water saturation and permeability, pressure change occurs quickly in the reservoir. Still, pressure measurements can be used to identify the reservoir's lateral continuity or estimate the volume of steam lost to the cold reservoir. Moreover, pressure measurements inside the reservoir help to improve geological interpretation and future developments of the area.

5.5.2.2 Pressure monitoring at the upper layers

Measuring pressure at the permeable upper layer Wabiskaw Sand is crucial to ensure reservoir containment during the project. Ideally, if there is no fluid flow from the reservoir, the pressure in the upper layers should remain constant over time. Nevertheless, due to these formations' drainage conditions, the pressure behavior can be affected by factors other than fluid flow, such as poroelastic response to reservoir expansion and thermal expansion of pore fluids.

As demonstrated by simulation results above, conduction can transfer heat from the reservoir to the overlying layers. The thermal expansion of the fluids hosted in the pores of these formations can lead to pore pressure increments if the excess pore pressure is not quickly dissipated. The continuous lines in Figure 5-16 show the pressure and temperature behaviour of the Wabiskaw Sand for ten years, assuming no flow in all boundaries of the model (undrained conditions). Although a change in pressure is observed, it does not necessarily mean hydraulic communication with the reservoir. The results show that pressure and temperature exhibit similar behaviour and are directly correlated since they follow the same trend over time, but temperature change occurs sooner than pressure. Thus, the change in pressure observed in this zone results from the temperature change. The thermal expansion of the water contained in the porous and the undrained condition led to pressure increments. Yang (2013) reported a similar behaviour for the caprock and addressed possible issues with shear failure due to low effective stress. Also, Kosar (1989) and Mohajerani (1989) found thermal-induced pore pressure when heating samples in experimental research.

A simulation case with drained boundary conditions was completed to evaluate the pressure response in Wabiskaw Sand when temperature increases. The drained simulation case assumes that the layer is connected to an infinite aquifer that allows pressure dissipation (dotted lines in Figure 5-16). Results show that under drained conditions, pore pressure remains constant when the temperature increases.

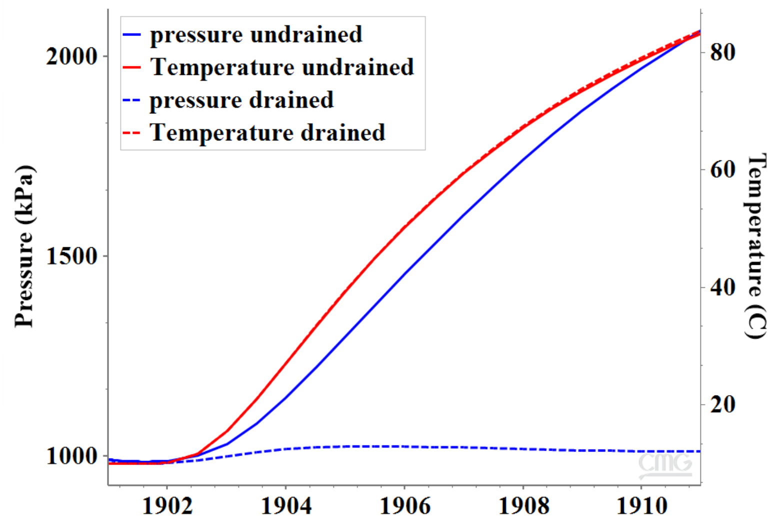


Figure 5-16 Simulated pressure and temperature at Wabiskaw Sand monitoring zone for drained and undrained conditions.

Furthermore, the expansion of the reservoir caused by thermal expansion and effective stress reduction leads to compression in the upper layers. The poroelastic response of the formation at undrained conditions results in pressure build-up. Both thermal-induced pore pressure and poroelastic response are phenomena that occur under undrained conditions. Such conditions can be given by low permeability of the rock or lack of lateral continuity that prevents flow. Well-testing in the preamble zone can help to estimate permeability as well as the distance to a no-flow barrier.

Undrained conditions can lead to false alarms in reservoir containment monitoring programs. Also, the permeability of the layer should be considered when planning monitoring programs to evaluate measurement coverage and representativeness.

5.5.3 Deformation monitoring

Extensometers that measure displacements in different directions can be installed in observation wells. Figure 5-17 illustrates the evolution of horizontal displacement in a cross-section perpendicular to the wells' trajectories at different times. Results obtained in the current research are in good agreement with the observations obtained at the UTF Phase B reported by Collins (1994). Results suggest that the horizontal deformation measured in the subsurface can change significantly with time; at early times when the steam chambers are still small, the deformations are concentrated around the well-pairs and advance towards the side as chambers grow. Deformation occurs in both directions, as illustrated in Figure 5-17. The rate of deformation and the absolute value at a certain time depend on the chambers' geometry and location. Well-pairs, where steam chambers grow fast, will result in higher horizontal deformation, such as the case of Well-pair 5, which presents noticeable deformations after two years.

Figure 5-18 illustrates the predicted lateral displacement at injectors' depth. There is a lateral displacement resulting from the rock's expansion within the steam chambers; nevertheless, the interaction between the chambers of different well-pairs increases as the chamber becomes larger. Thus, the displacement caused by one steam chamber in one direction is affected by the displacement caused by the adjacent chamber in the opposite direction. If the material is homogeneous, a line of symmetry could be drawn at each time where horizontal displacements are negligible due to the interaction adjacent well-pairs. Similar to Figure 5-17, Figure 5-18 shows a marked difference between early and late times. This difference starts being noticeable when the steam chambers coalesce, and more displacement is accumulated at the edge of the well pad.

Therefore, the location where the most significant horizontal displacement occurs is dynamic and depends on what is happening in the SAGD process. The dynamic behavior makes the design of horizontal displacement monitoring challenging since time should also be included to identify the optimal location. If the purpose of monitoring is reservoir containment, monitoring horizontal displacement at late times can help determine if displacements are larger than expected. Large horizontal displacement can be associated with high shear stress levels at the flank of the pads that could represent a potential hazard to containment. Finally, some horizontal displacement is also predicted at the ground surface, which could be monitored with high precision instrumentation such as Dual-GPS and InSAR.

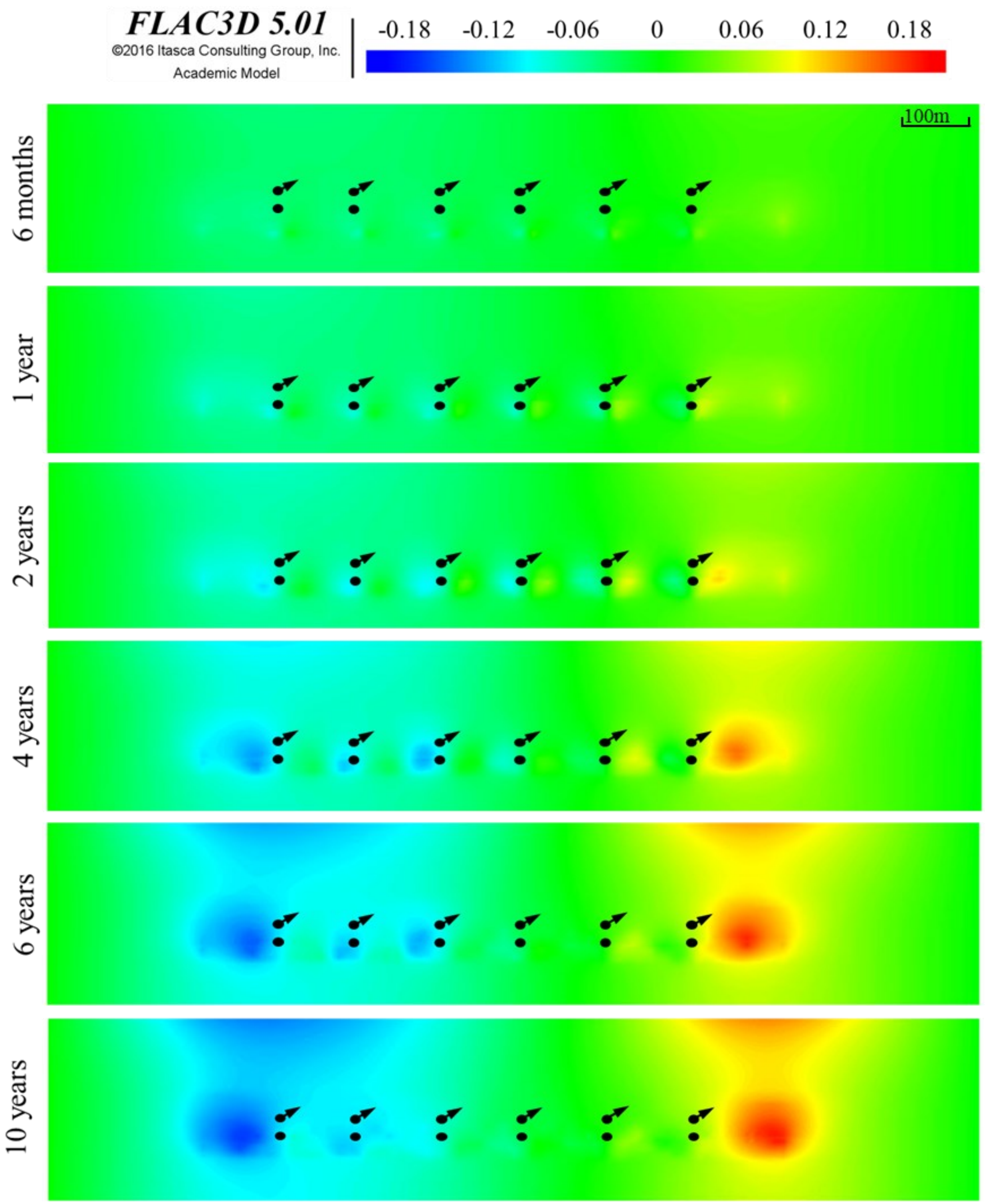


Figure 5-17 2D cross-section of horizontal displacement perpendicular to wells' trajectories for different times.

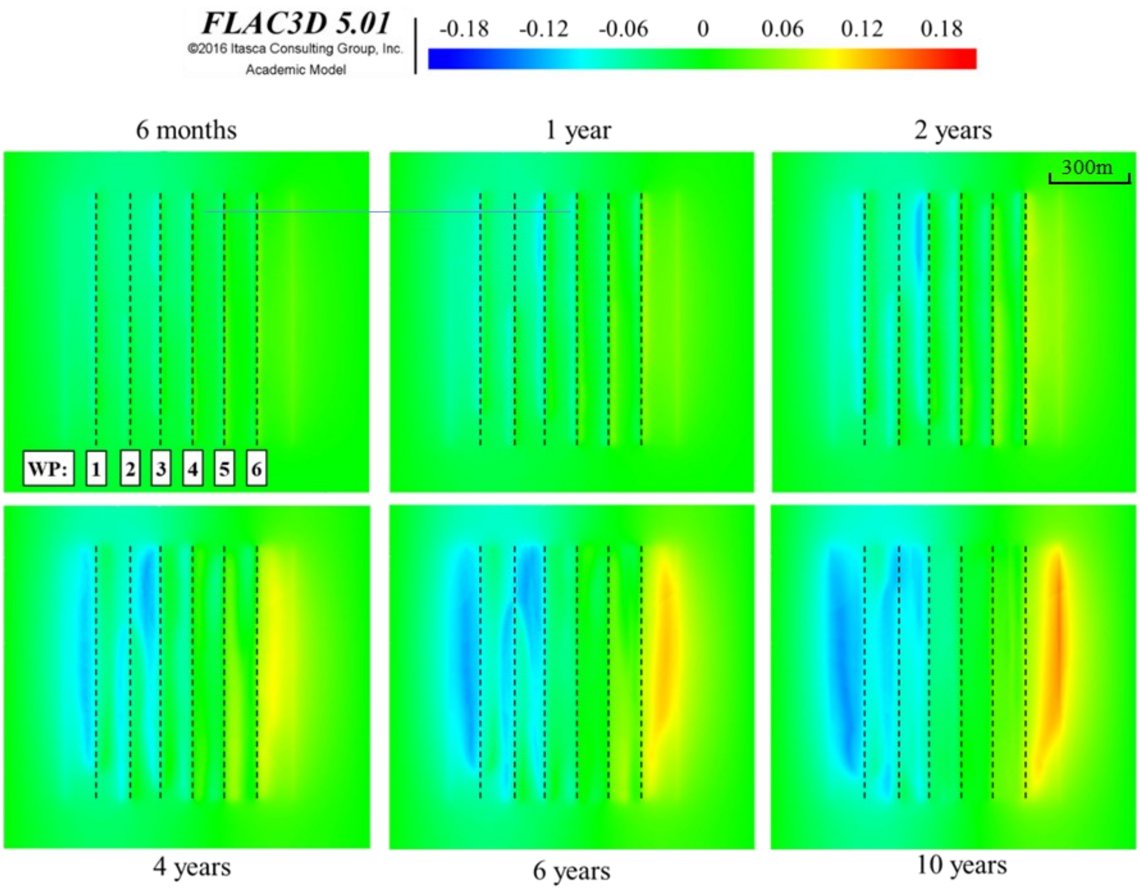


Figure 5-18 Horizontal displacements at injectors' depth for different times.

5.6 Surface Heave

Ground surface deformation has become the most popular geomechanical monitoring technique and is currently performed at most thermal projects in Alberta. Even though techniques such as InSAR and tiltmeters have gained popularity, the methodology followed to place instrumentation has not been standardized. The location of the sensors follows geometries as square grids and is not intended to answer specific questions of the process. Suppose the locations are strategically selected based on the value of information. In that case, the process can be improved, leading to cost reduction without affecting the quality of results, maximizing the information obtained from monitoring. In this section, simulations results of ground surface heave are analyzed to investigate how it aids in understanding subsurface processes.

Ground surface deformation measurements are claimed to be a useful tool to monitor processes at the reservoir such as steam chamber growth and caprock deformation. Even though ground deformation results from subsurface deformation processes, it is an indirect measurement since external factors can affect the measurements. There is a significant lack of information about formations above the reservoir that impacts the reliability of ground deformation measurements to represent subsurface behaviour. Geomechanical characterization has mainly focused on the reservoir and caprock, while the geomechanical behaviour of more surficial layers has not been studied yet. These limitations become more significant for deeper reservoirs where the deformations are transmitted through a thicker unknown medium.

It is also well known from studies of the area (Andraishek, 2003) that the glacier deposits overlaying the caprock are not homogeneous, adding more uncertainty to the measurements. In addition, part of the displacement generated in the subsurface is attenuated in the upper layers making the ground deformation an indirect measure of subsurface behaviour. Figure 5-19 illustrates the simulated vertical deformation at the base of the Clearwater caprock and the ground surface. The figure demonstrates the loss of details reflected at the surface displacement compared to what happens at the base of the caprock. Thus, ground displacement information is not accurate in describing the deformations in the reservoir and caprock.

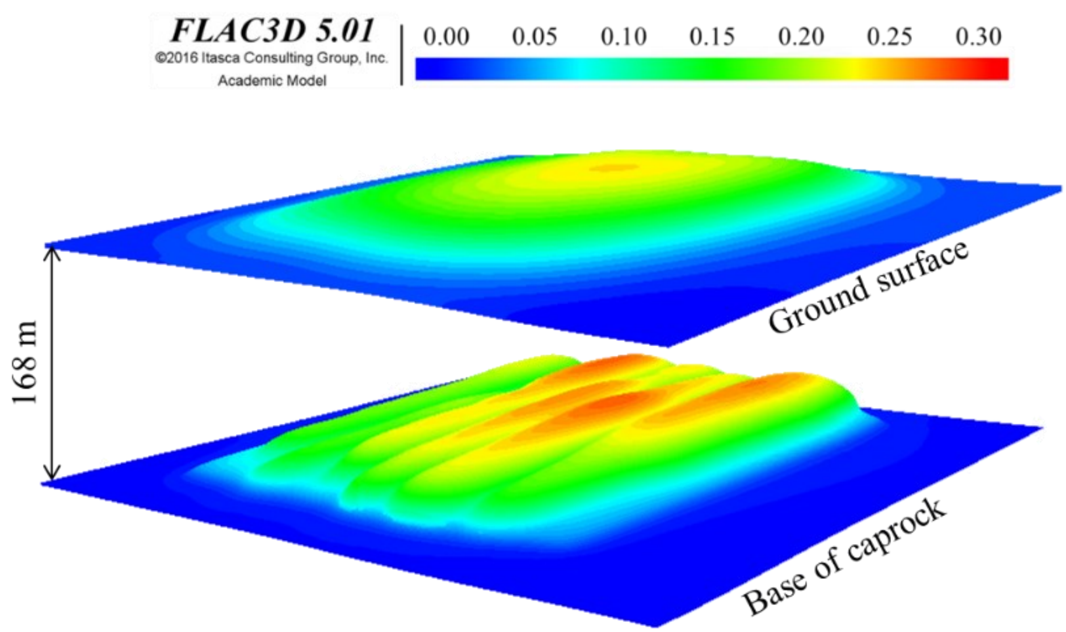


Figure 5-19 Predicted vertical displacement at the base of the caprock and ground surface after 4 years of SAGD

Vertical ground displacement for different times throughout the simulations is presented in Figure 5-20. Simulation results reveal that ground deformation is not homogenous in the studied area. Initially, there is a clear trend of higher displacements in the northeast region of the pad. This zone corresponds to the toes of Well-pair 5 and Well-pair 6, which have been identified as the well-pairs where the steam chambers grow faster due to better reservoir properties. After five years, the highest deformation occurs at the central-east of the pad due to chamber coalescence.

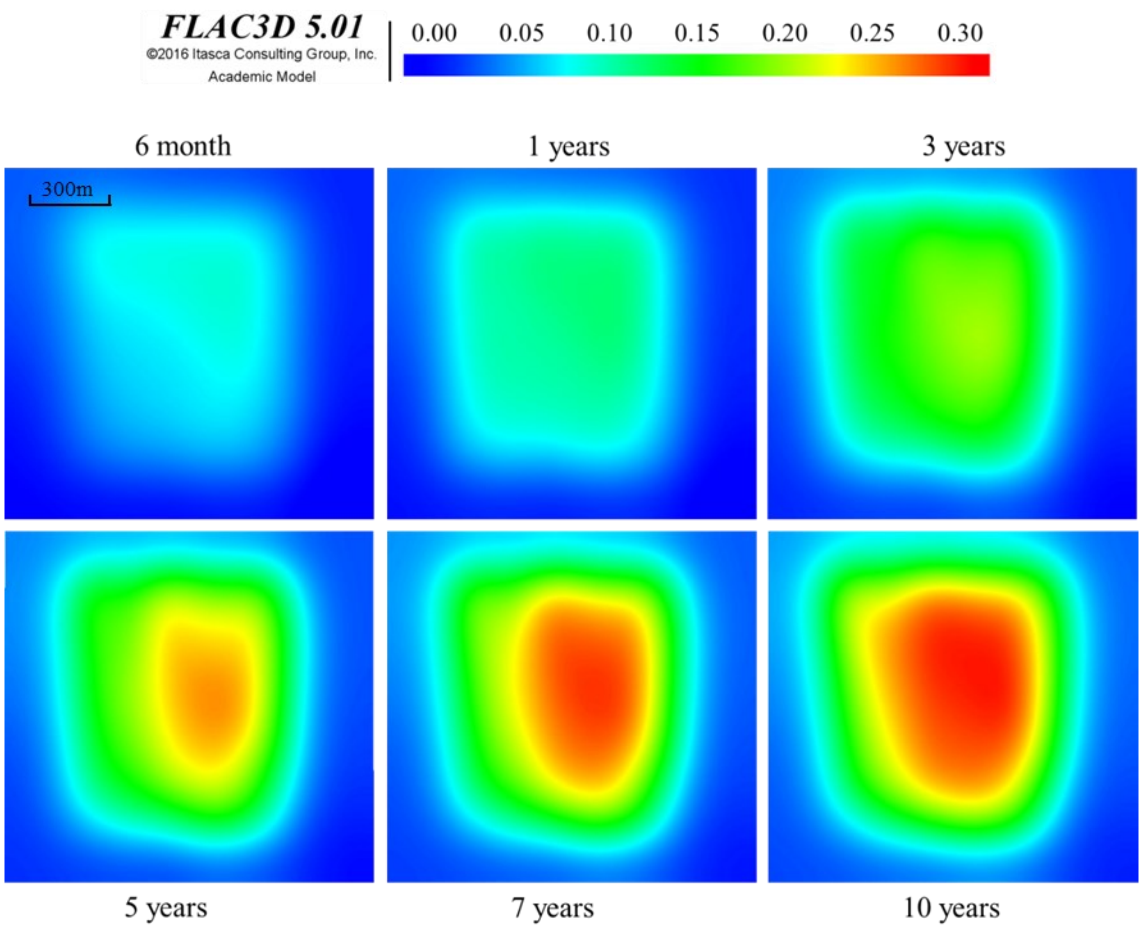


Figure 5-20 Predicted ground surface deformation in meters during SAGD operations below MOP

Even though ground displacement cannot capture many details, some field data suggest that ground deformation is related to reservoir performance and steam chamber growth. In order to analyze the ground deformation results and the associated subsurface processes that cause them, displacement at the base of the caprock and temperature distribution at the top of the reservoir are presented in Figure 5-21 and Figure 5-22, respectively. In addition, Figure 5-21 displays a noticeable displacement at the top of Well-pairs 3's toe after three years that is not captured by ground deformation in Figure 5-20, showing the discrepancies between ground measurements and subsurface.

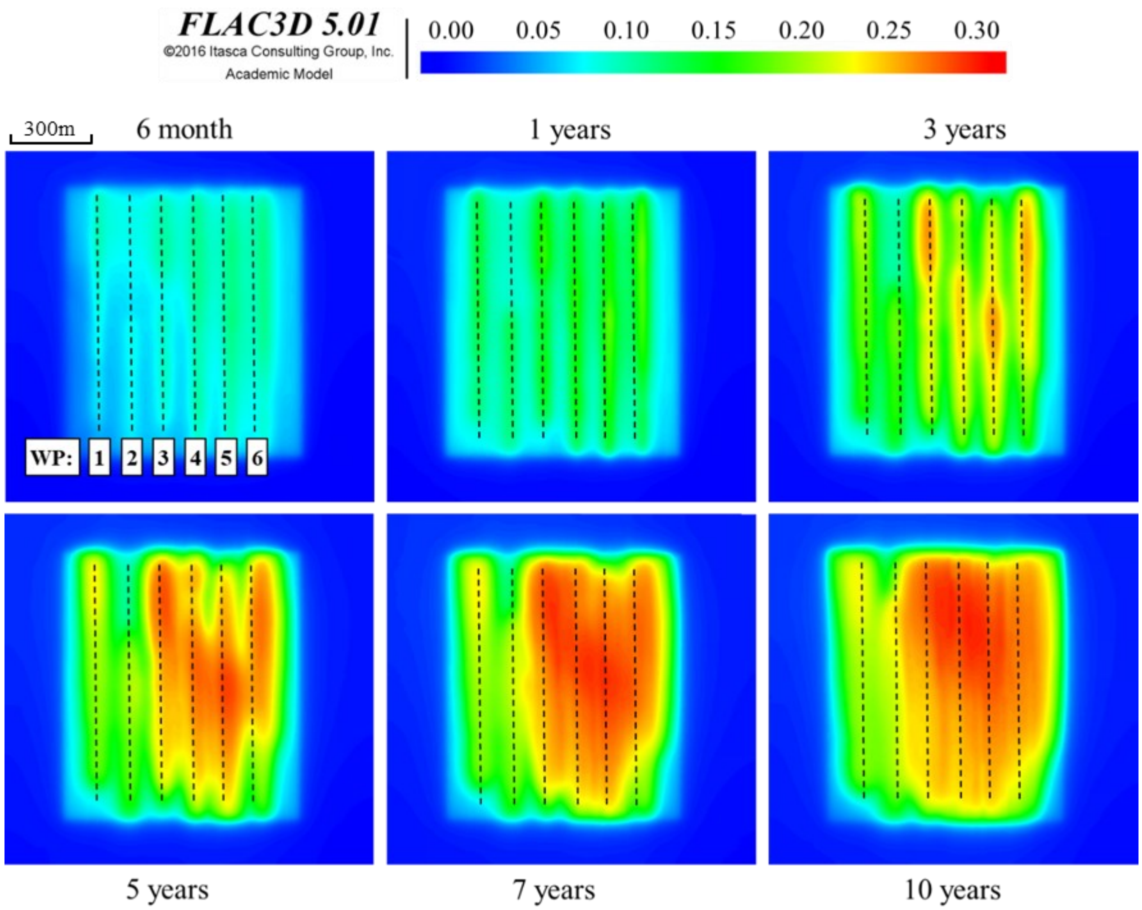


Figure 5-21 Simulated vertical displacement in meters at the base of the caprock during SAGD below MOP

Displacement at the caprock base results from the thermal expansion within the reservoir. Even though temperature disturbance at the base of the caprock is negligible for the first three years of SAGD (Figure 5-22), simulated ground displacement is as high as 10 cm. This vertical displacement at the ground surface results from the thermal expansion of the reservoir at the well-pairs elevation when the steam chambers are still immature. On the other hand, for late times, when the steam chamber reaches the base of caprock, results suggest a good correlation between temperature and vertical displacement at the base of the caprock.

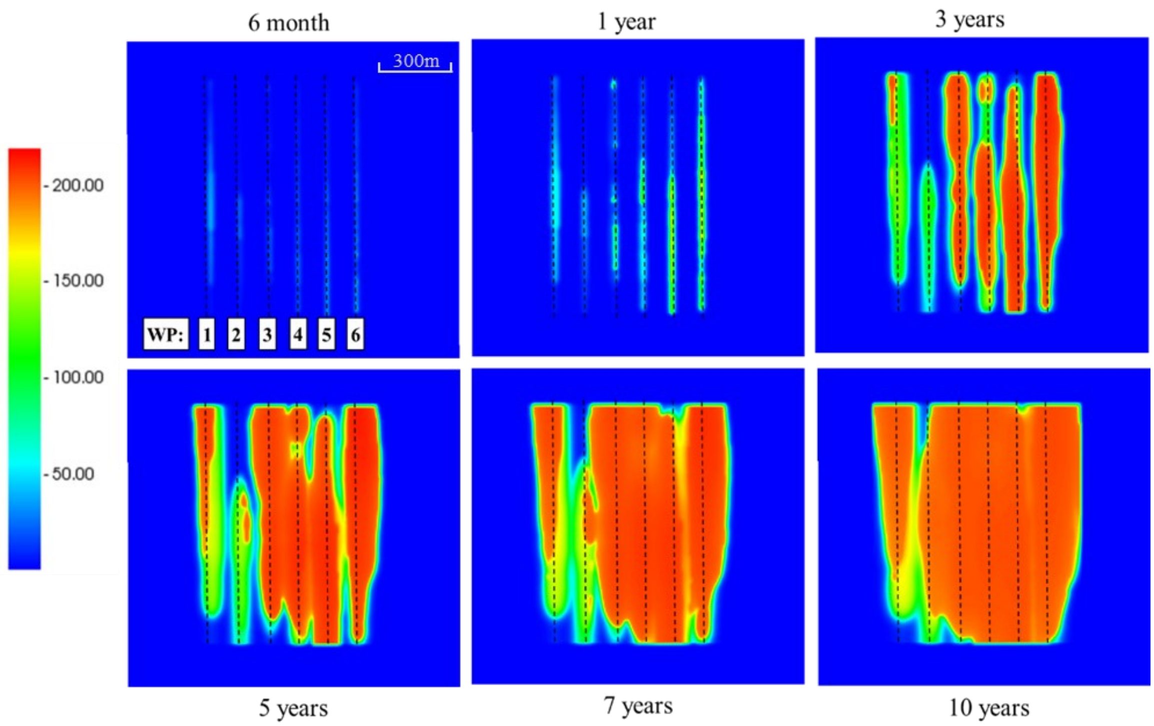


Figure 5-22 temperature distribution at the top of the reservoir during SAGD below MOP

Although ground deformation is limited in revealing subsurface behavior, it can add significant value when it is analyzed with other sources of information such as geological heterogeneity. Moreover, analogous to steam chamber coalescence, vertical deformations from different well-pairs will eventually be added to each other, making it challenging to differentiate the displacement source. Therefore, ground deformation can be a helpful monitoring technique to infer and propose a hypothesis but requires more monitoring techniques and subsurface information to explain the observed data.

Simulation results can also help analyze displacement transmission from the subsurface to the ground to evaluate displacement attenuation at the upper layers. Figure 5-24 shows vertical displacement in a 2D cross-section perpendicular to the well-pairs from the ground surface to the under-burden. The results show how some well-pairs contribute to the vertical deformation more than others; such is the case of the well-pairs located at the east of the pad. These results explain why there is more ground deformation in this area. Nonetheless, displacements from all the Well-pairs are added to each other as they are transferred to the upper formations. This behavior is observed even at early times when displacements are still small.

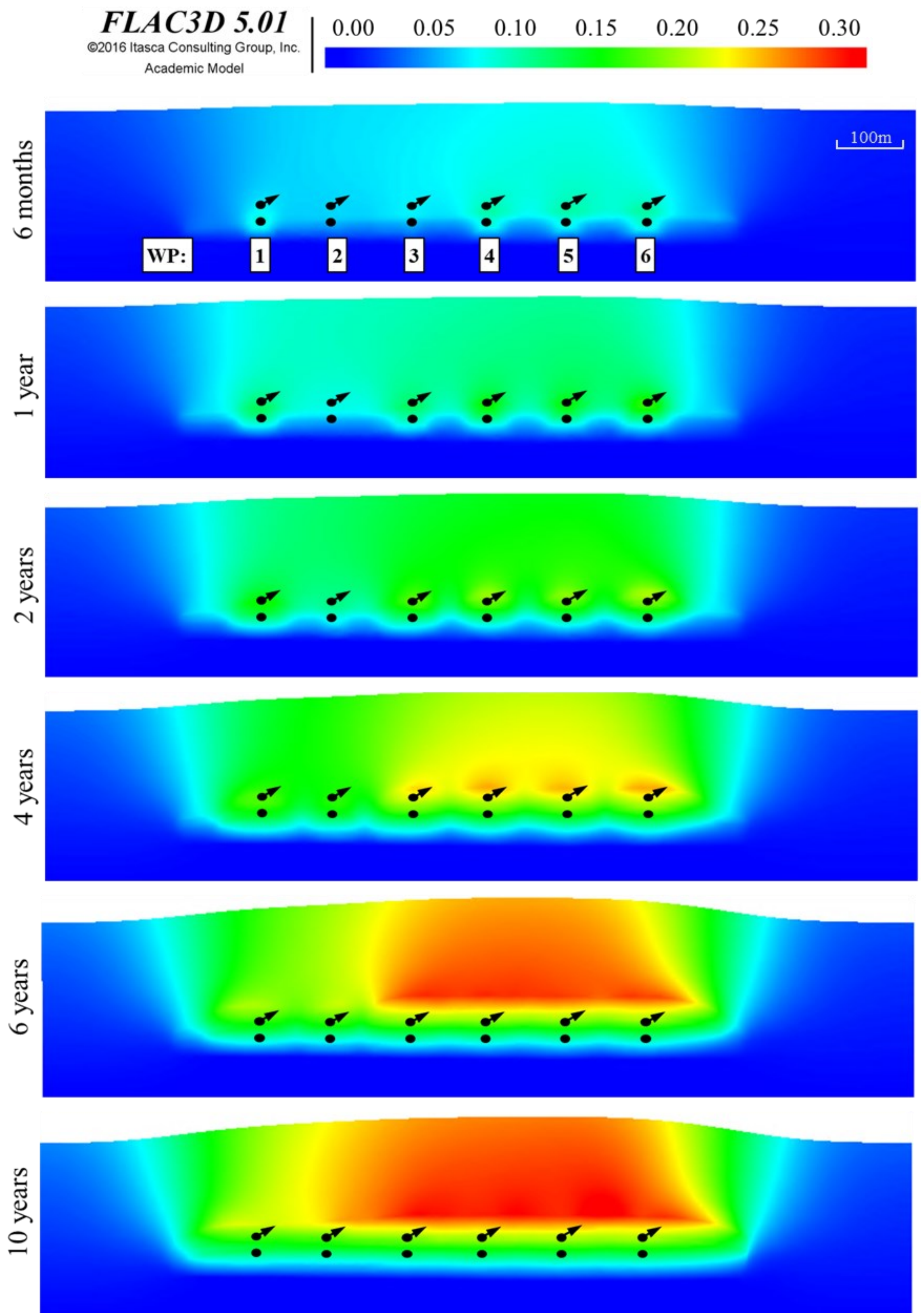


Figure 5-23 2D cross-section of simulated vertical displacement perpendicular to the well-pairs trajectory for different times.

Vertical displacement may also vary the well's trajectory. In this case, the variation can be the result of the wellbore completions and the reservoir heterogeneity. For example, Maxwell (2009) reported more ground deformation measured by tiltmeters at the toe and heel of the well associated with different injection points along the well and the corresponding pressure and temperature drop. However, it has been demonstrated that reservoir heterogeneity and steam chamber growth also play a key role in vertical displacement. Simulation cases assume the well is continuously perforated; such steam chamber growth is governed only by reservoir heterogeneity. Figure 5-24 illustrates the results of simulated vertical displacement and temperature along Well-pair 6. Temperature results show poor communication between the injector and the producer at the heel, which results in lower vertical displacement in the area. Poor communication between the injector and the producer results from a low permeability layer between the wells captured in the heterogeneous model. When analyzing monitoring data, it is essential to consider that it can be affected by natural conditions as subsurface heterogeneity and man intervention as well placement and completions.

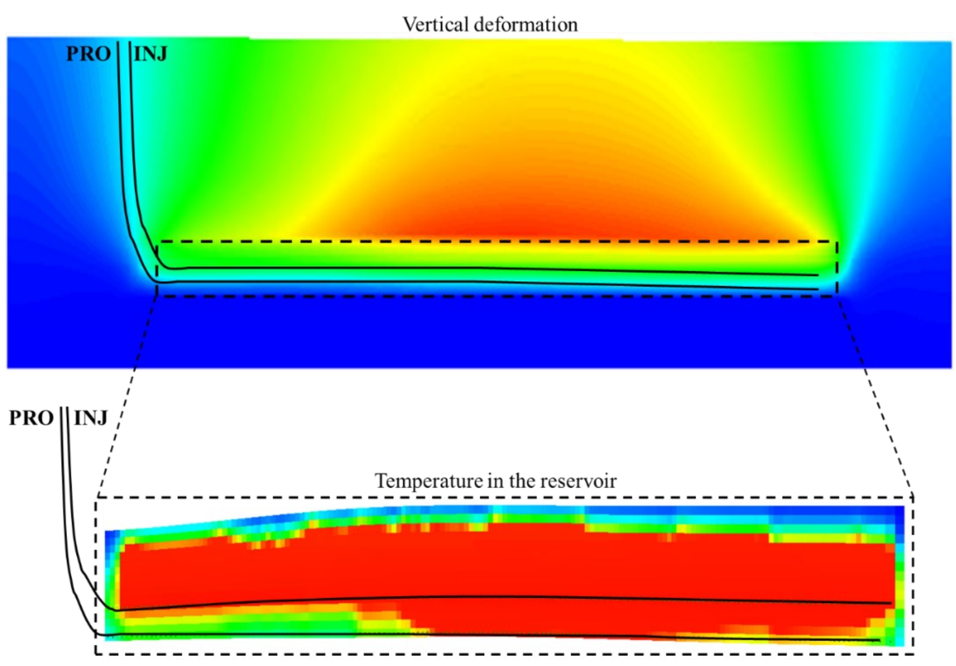


Figure 5-24 2D cross-section along Well-pair 6 for vertical displacement and temperature distribution within the reservoir.

5.6.1 Ground surface heave in homogeneous reservoirs

The previous discussion demonstrated how vertical deformation at the ground surface is affected by heterogeneity in the reservoir. To enlighten the discussion, vertical displacement for heterogeneous and homogeneous models is compared in Figure 5-25. The homogeneous model considers average petrophysical properties and a single geomechanical facies in all formations. Besides, the homogeneous model assumes the tops of the formations are flat throughout the studied area using the average depth of each formation. As a result, the displacement obtained for homogeneous and heterogeneous models are significantly different. Firstly, the predicted ground displacement for the homogeneous model is higher than the predictions obtained for the model with heterogeneity, which is explained by the steam chambers growth that occurs simultaneously and homogeneously inside the reservoir. Secondly, the shape of the deformation map at the ground surface is different; for the homogeneous case, the results suggest that the displacement obtained at the surface has a 'dome' shape with the highest deformation located at the middle of the pad. On the other hand, the heterogeneous model results show the maximum vertical displacement at the eastern side of the pad, which corresponds to the best reservoir quality, as explained previously.

These results demonstrate that some information about the subsurface heterogeneity and the consequent steam chamber architecture can be inferred using ground deformation data. However, the inferred analyses carry a lot of uncertainty since the measurements are indirect. Therefore, it requires to be confirmed using complementary data as reservoir characterization or different monitoring techniques.

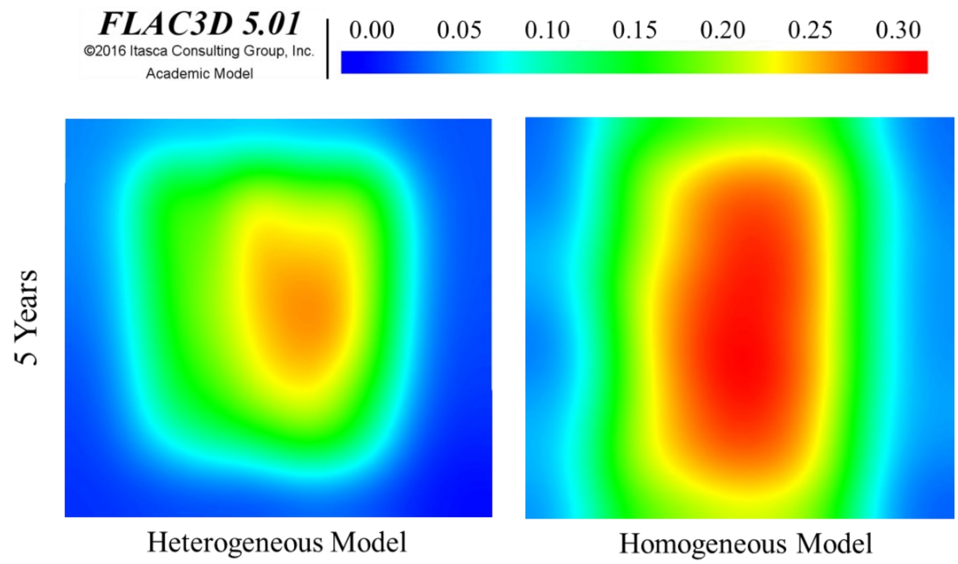


Figure 5-25 Simulated vertical displacements at the ground surface for homogeneous and heterogeneous models.

5.6.2 Vertical displacement and safety factor

Given that vertical displacement is the most common geomechanical monitoring technique, it is crucial to evaluate how much it helps address the project's safety. Figure 5-26 illustrates the factor of safety for shear stress at the base of the caprock for different times during the project. The results suggest that the safety factor is highly correlated with vertical displacement and subsequently with temperature distribution. As the temperature increases at the reservoir top, the safety factor decreases approaching failure conditions.

The safety factor also exhibits low values at the edge of the drainage area due to the differential displacement generated from the thermal expansion of the reservoir. Similar behavior was identified by Xiong & Chalaturnyk(2015), demonstrating that the highest risk of shear failure is at the flank of the chambers. For the late times, there is a slight difference of safety factor between seven and ten years of simulation, which corresponds to a reduction of injection pressure in the operating conditions.

Even though the results suggest that the safety at the base of the caprock is highly correlated to temperature distribution, it is important to keep in mind that Figure 5-26 only represents 4 meters at the bottom of the caprock. And even when the safety factor is reduced to 1 and failure occurs at this depth, it does not mean that failure propagated through the whole caprock.

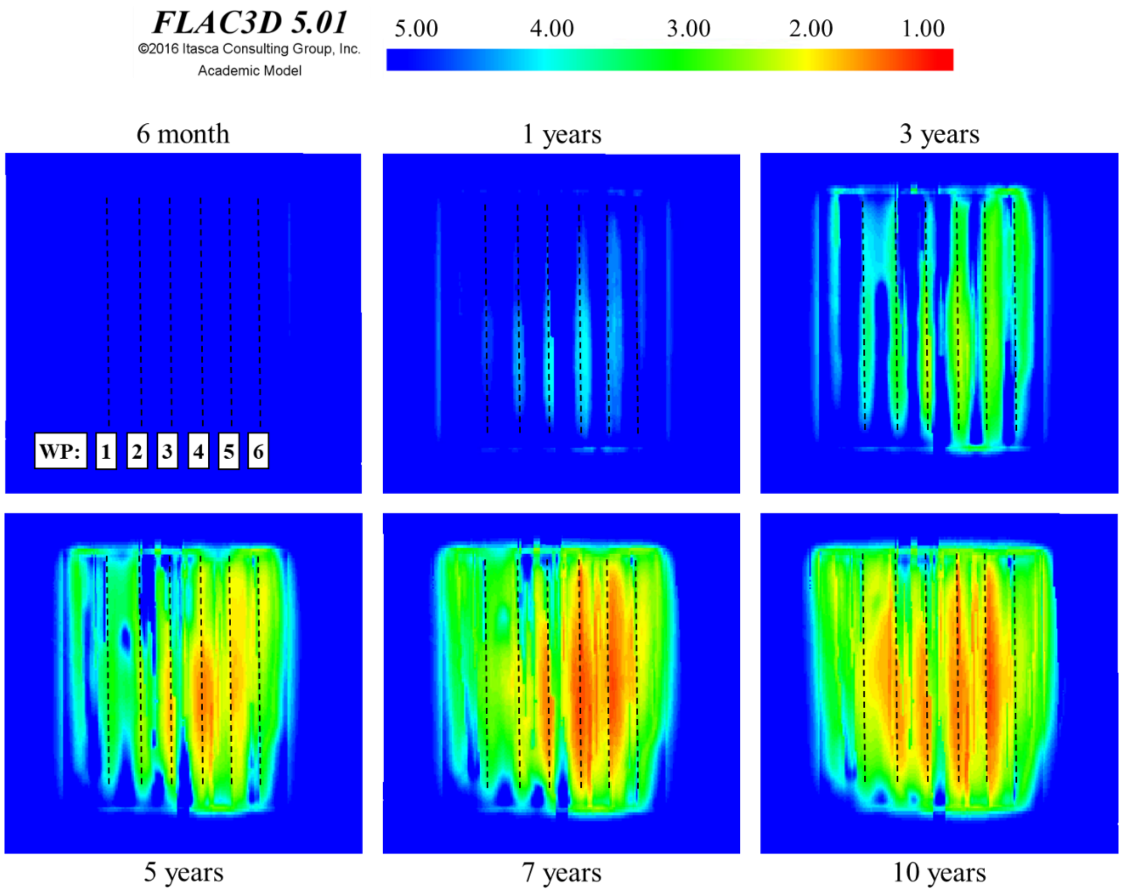


Figure 5-26 Safety factor at the base of caprock for SAGD below MOP

5.6.3 Tensile failure and ground deformation

The main geomechanical risks associated with SAGD operations is reservoir containment loss. Therefore, one of the primary purposes of geomechanical monitoring during SAGD is to ensure the integrity of the caprock throughout the SAGD project. According to the current regulation in Alberta, the injection pressure is limited to 80% of the minimum principal stress at the base of the caprock. In order to evaluate how effective ground monitoring is to capture or anticipate a tensile failure in the caprock, one simulation case is designed assuming injection pressure equals the minimum principal stress at the reservoir. Simulation results for such conditions show that tensile failure at the base of the caprock initiates after 5.5 years of operations, as presented in Figure 5-27. The shoe that failure initiates at the toe of Well-pair 5 and middle of Well-pair 4, which corresponds to the regions where the steam chambers grow faster. The top of the reservoir becomes at high-pressure and high-temperature conditions once the steam chamber reaches it. These conditions facilitate the initiation and propagation of tensile failure.

The results show that vertical displacement monitoring at the ground surface does not capture the initiation of the tensile fracture. Even the vertical displacement distribution at the base of the caprock does not show a clear sign associated with the fracture's initiation. Moreover, higher displacement in the vicinity of the fracture has been observed previously for the regions where steam chambers grow significantly without exhibiting failure. Furthermore, the predicted shape of vertical displacement at the surface is similar to those presented in Figure 5-20 for a case where tensile fracture was not predicted.

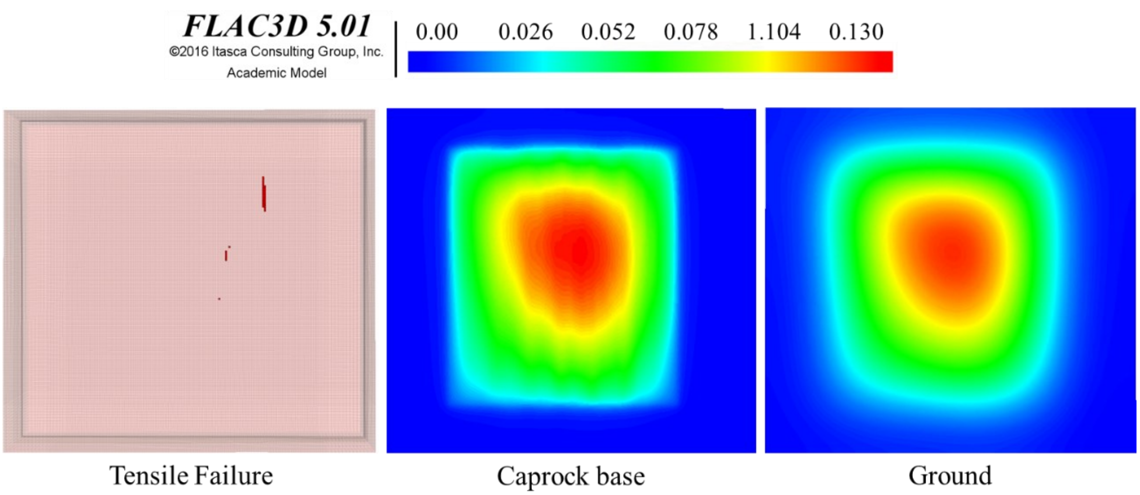
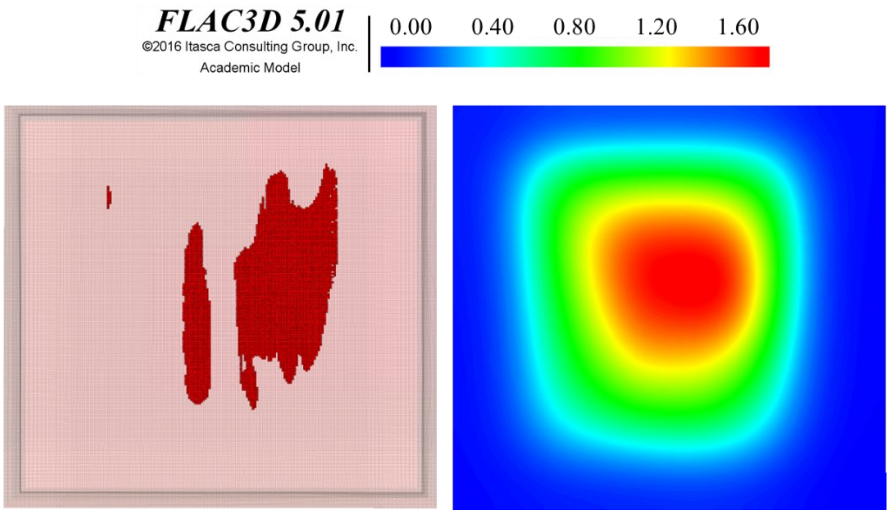


Figure 5-27 Tensile failure at the base of the caprock and vertical displacement at caprock base and ground surface.

If SAGD operations continue after the tensile fracture is initiated at the high-pressure conditions, the tensile fracture propagates through the base of the caprock, especially at the points that are exposed to high-pressure and high-temperature conditions. Figure 5-28 illustrates the model's aerial view of tensile failure and the associated displacement after ten years of operations at high-pressure conditions. At this point, tensile failure not only occurs in the vicinity of Well-pair 5 but is propagated all around Well-pair 4, 5, and 6. There is also failure at the top of Well-pair 3 and some isolated blocks at the toe of Well-pair 1. All these areas correspond to the steam chambers growing considerably due to the reservoir's good quality. Similar to the results obtained for tensile fracture initiation, ground displacement cannot capture failure propagation. Although larger vertical displacement is predicted at the ground surface when a tensile failure occurs, it is still limited to capture the location of the failure.



a) **b)**

Figure 5-28 a) tensile failure after ten years of operation above MOP. b) Vertical displacement at the ground surface after ten years.

Finally, the predicted heave obtained for cases above MOP and below MOP is compared at the eastern side of the pad where displacement is the highest, as illustrated in Figure 5-29. Initially, surface heave is not predicted for the circulation phase; this can be explained by the fact that there is no steam chamber in the reservoir. Later, once SAGD phase starts, there is a sharp increment of vertical displacement in both cases caused by the changes in pore pressure that generate expansion in the reservoir.

The vertical displacement rate is not constant as SAGD advances, being higher at the beginning when abrupt pressure and temperature changes occur. Furthermore, the predicted heave shows a significant increment of heave when injection pressure is increased. However, the heave history does not exhibit any noticeable change when failure initiates (5.5 years) or when propagating, suggesting that ground surface monitoring is limited to capture caprock failure.

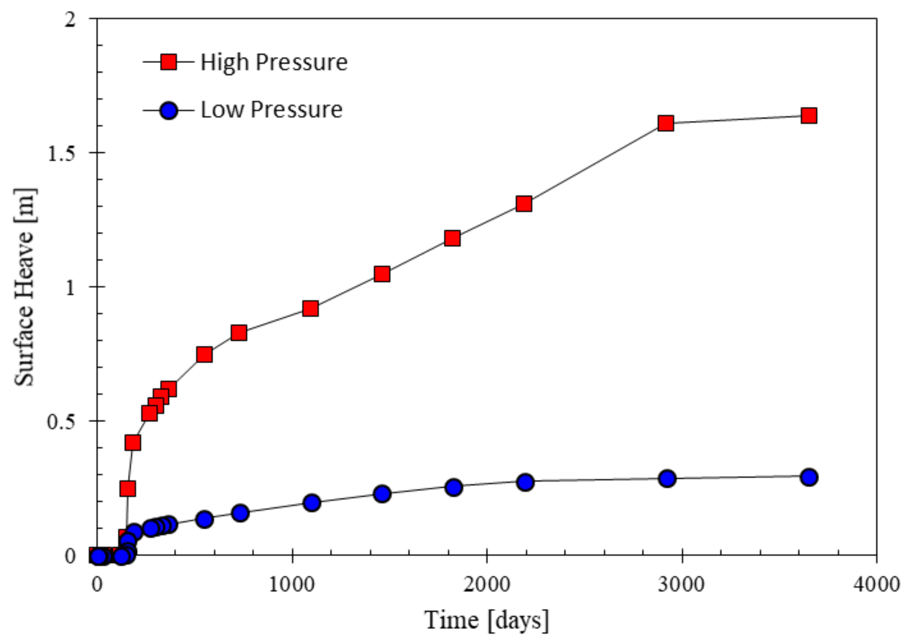


Figure 5-29 Comparison of predicted surface heave for SAGD operating below MOP and above MOP.

5.7 Production data monitoring

Understanding the behavior of the subsurface during thermal recovery requires analyzing all available information together to find information that can complement each other and support the different hypotheses. Production data interpretation plays a key role in revealing the different processes within the reservoir and the conditions that lead to such behavior. This section analyzes the production oil rate from all the producer wells to see how it correlates with the deformation predicted by simulations. Different data could also be used as injection rate or cumulative oil production to evaluate the growth of the steam chamber and the drainage area, respectively.

Since the model used for the simulation was heterogeneous, the production from each well-pair is expected to be different. Figure 5-30 presents the oil rate for all the producer wells over ten years of operations. From the results, a significant difference in productivity is observed between different producers. For instance, Producer 4 exhibits a high production rate for the simulated time, while Producer 2 performs poorly. Also, the production rate is not constant and, in most cases, increases with time, which corresponds to the advancement of the steam chamber that allows recovering oil from more regions of the reservoir.

Well-pair 2 shows a direct correlation between oil rate and steam chamber growth presented in Figure 5-22. Temperature distribution at the top of the reservoir shows no chamber development at the toe of the well-pair, resulted from the poor reservoir quality around this area. The results also agree with the vertical displacement results showing a lower value around this well-pair than the others.

Similarly, Well-pairs 4, 5, and 6 exhibited the pad's best productivity and prominent steam chamber growth. Simulations show early coalescence of chambers at this area of the pad, and vertical displacement at the base of caprock and ground surface is higher than anywhere else in the pad. Therefore, well performance can be used to confirm the information previously interpreted from deformation data.

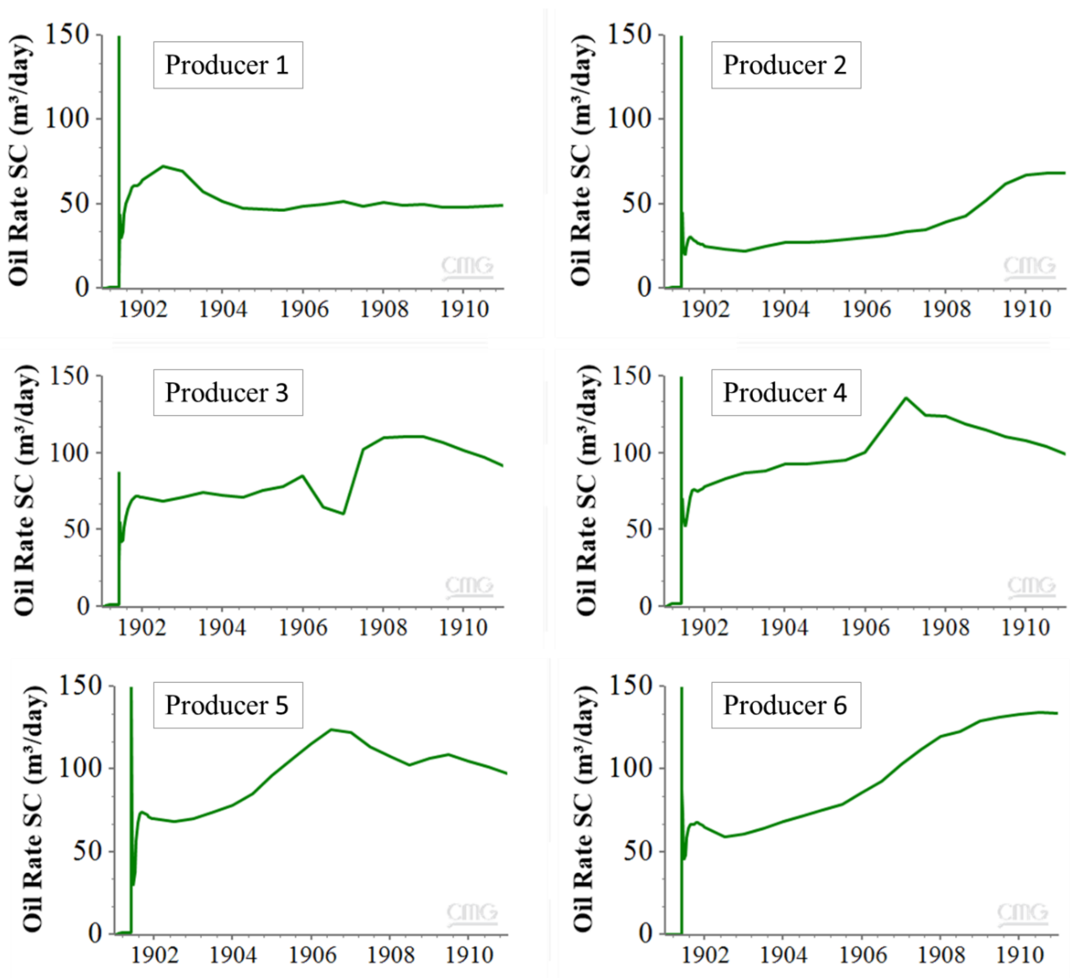


Figure 5-30 Oil rate production from all producer wells of the pad

CHAPTER 6 SELECTING INSTRUMENT LOCATIONS FROM GEOLOGICAL INFORMATION

6.1 Introduction

Reservoir containment loss risk has been identified as one of the main concerns for thermal operations. Companies spend substantial resources on de-risking thermal operations in oil sands. The de-risking process usually involves evaluating the likelihood and the consequences of reservoir containment loss. Also, the process includes plans to prevent and mitigate such incidents.

One of the most used strategies to prevent caprock failure events relies on monitoring programs. Nevertheless, if monitoring programs are not properly designed, it can end up being costly and inefficient. To avoid this issue, a Systematic Approach used in geotechnical engineering has been considered for SAGD projects (see CHAPTER 3). The eighth step of this systematic approach recommends selecting the instrument locations based on engineering criteria to successfully fulfill the monitoring purposes minimizing associated costs.

In this chapter, a simple methodology based on geological data is proposed to aid in selecting the optimal locations for placing monitoring instruments. The methodology avoids using numerical models that require complex resources as experienced staff and high computational capabilities. The methodology uses fundamental properties in the geological models to predict the project's regions where the risk associated with reservoir containment is higher.

The Systematic Approach also recommends considering locations to be monitored where the parameters are expected to change considerably within the study area. For SAGD monitoring, such locations are usually related to high-risk zones and include zones where pressure, temperature, and deformation are expected to have more significant changes compared to other areas.

The aim of this chapter is to propose a methodology that helps to make improved decisions on monitoring plans based on the heterogeneity of the caprock and reservoir that plays a key role in the reservoir performance and the geomechanical response of the subsurface reserve.

6.2 Conditions that facilitate caprock failure

Similar to any material, failure in caprock is reached when the applied stress overcomes the strength of the material. In thermal recovery, the applied stress is the result of steam injection and steam chamber growth within the reservoir; thus, the applied stress on the caprock is mainly dominated by reservoir properties such as permeability and water saturation. Identifying regions where the steam chamber's growth occurs and a significant amount of bitumen can be swept is vital not only for economic analysis but for risk analysis to know where large stresses are applied on the caprock.

On the other hand, the strength of the caprock is given by failure criteria parameters as cohesion, friction angle, and tensile strength. Strength parameters in the caprock usually depend on different factors such as pre-existing discontinuities, in-situ stress conditions, pre-consolidation conditions, particle size distribution, and aging. However, factors as particle size distribution can vary significantly throughout the area of interest. Understanding how these factors change is crucial to identifying the caprock's weakest zones where failure is likely to initiate or propagate.

Furthermore, geological features as silt layers in the caprock and mud bodies in the reservoir can govern the deformation behavior as it was studied in CHAPTER 5. Fracture propagation and material deformation also depend on the thickness of the caprock showing a higher risk for thinner layers as presented by (Xiong & Chalaturnyk, 2015) where the impact of caprock thickness is analyzed in the safety factor calculation as presented in Figure 6-1. Thus, risk can be quantified by the thickness, continuity, and strength of the caprock, and the development of the steam chamber underneath.

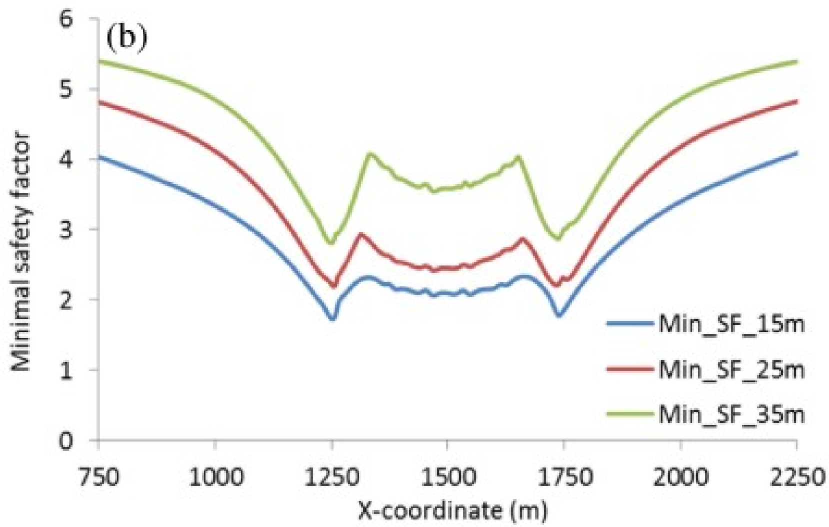


Figure 6-1 Impact of caprock thickness on the safety factor in SAGD. Taken from (Xiong & Chalaturnyk, 2015)

If the steam chamber becomes large quickly at a certain point, and the upper caprock is thin or weak, this can be classified as a zone with a potential failure initiation. Figure 6-2 schematically illustrates such conditions, where a Well-pair is vertically aligned with a thin section of the caprock. Thus, if operating conditions overcome the strength of the caprock at any point during SAGD, reservoir containment might be lost.

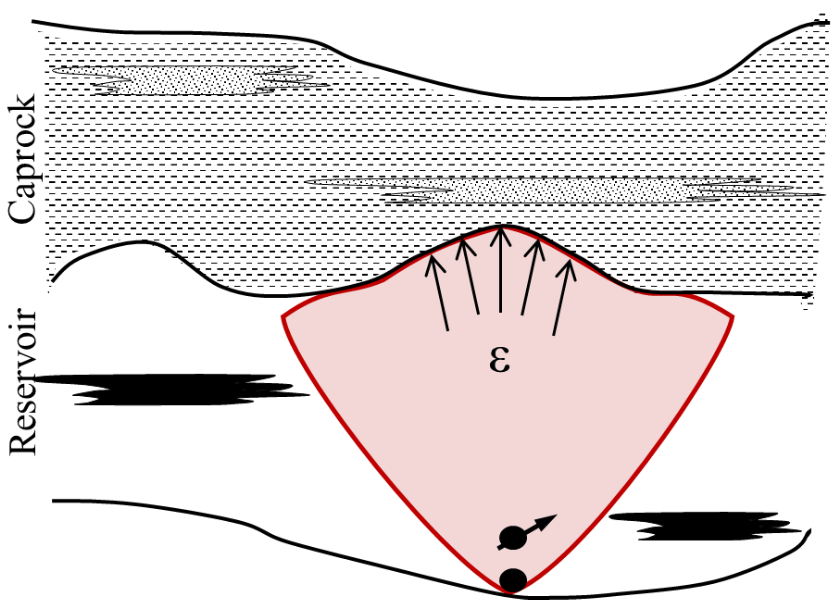


Figure 6-2 Schematic of conditions to initiate fracture in the caprock

6.3 SAGD risks at injection stage

Analogous to geotechnical projects as slope stability and earth structures, SAGD risks can be associated with the project stage. Early times include the circulation phase and the first couple of years of the SAGD phase. As presented in CHAPTER 5, during this period, the steam chambers are still small and, in many cases, have not reached the top of the reservoir yet. At this point, the main concerns are related to steam accumulation in zones of high water saturation within the reservoir, similar to what occurred in Joslyn Creek and flow through high permeability pathways. High permeability pathways can be separated into two different categories, pre-existing or SAGD-triggered. Pre-existing fractures or faults can serve as channels that communicate the reservoir to the upper layers.

In addition, given the low mobility of bitumen at the initial stage, pressure build-up around the wellbores can occur at early times, leading to hydraulic fracture initiation and propagation when operated at a pressure high enough to initiate the fracture. Considering the stress state within the reservoir in the Athabasca region, a vertical fracture is likely to occur within the reservoir. Nevertheless, if the operating conditions are kept between the admissible limits, the likelihood of a fracture remains low.

As mentioned above, to assess risk, two aspects need to be considered, likelihood and consequences. Even though the likelihood at this stage is low if risk is adequately managed, it could lead to major consequences if enough steam is accumulated within the reservoir to cause Joslyn's like event. If reservoir containment loss risk is identified during the early times of the project, there should be a monitoring program to help reduce the risk rank. This program can be temporal while the risky operation takes place, as a high-pressure injection for a short time. Once the operation is done, the monitoring devices can be removed.

6.4 SAGD risks at production stage

SAGD projects can be executed for a long period of time, up to 30 years. And even when the steam injection is concluded, the adverse temperature and pressure conditions can remain within the reservoir for years since it can take years to dissipate temperature and pressure. Furthermore, the materials usually go under plastic deformation, which results in a permanent alteration of the stress state (Hossini, Mostafavi, & Bresee, 2018).

After years of operation, the steam chambers start to coalesce, leading to a single massive chamber that includes all the project's Well-pairs. The resulting chamber's geometry depends on the well-pair spacing and reservoir properties as permeability and initial fluid saturation.

Xiong and Chalaturnyk (2015) studied the change of safety factor over time for a SAGD case, concluding that as the steam chamber advances and becomes larger, more load is applied to the caprock reducing the safety factor of the operation. This statement is valid for both tensile and shear failure in the caprock. Similar results were obtained in this research, as presented in CHAPTER 5, where the coalescence of some chambers started after four years, increasing the caprock's deformation. Even in the scenario of high pressure where the injection pressure equals the least principal stress, it takes over five years to initiate a tensile fracture at the caprock. Consequently, the risk of reservoir containment loss in SAGD increases as the project advances, as demonstrated by this research and previous studies. In addition, the environmental consequences of an incident could be worse at late times since there is more energy in the reservoir (large steam volumes) and bitumen is present in bitumen-water emulsion that facilitates its flow to contaminate the ground surface and underground aquifers.

Monitoring programs for late times should be strategically designed, and the dynamic behavior of some monitoring parameters should be considered when selecting the instruments' locations. If in-situ monitoring is required, the observation's location should be able to capture information that helps answer the key question throughout the project's life.

6.5 Caprock Quality Index CQI

Caprock formations for thermal projects vary throughout the area of interest due to different factors such as depositional environment and erosion. To assure reservoir containment during SAGD, the quality of the caprock is studied, and two different parameters are used, those are shale content and formation thickness. In Canada, the Clearwater formation is the main caprock of the Athabasca area, and it is a succession of marine mudstone and siltstone. It has been classified as a silty shale with interbedded siltstone and sandstone (Huag et al., 2014).

According to (Khani, 2022), one of Joslyn's incident roots was the lithology of the caprock at the failure location. Vertical wells of the area demonstrated low gamma-ray log values compared to the rest of the project. Low gamma-ray values in a shaley formation suggest a low volume of shale and high content of coarser material as silt or sand. When clays have a high content of coarser material, the clay structure, fabric, and consequently, engineering properties like strength and consolidation are significantly different from clay-rich materials (Terzaghi, Peck, & Mesri, 1996). Zadeh (2016) presented particle size distribution analyses obtained from multiple samples of Clearwater formation. Zadeh's results exhibit a high level of heterogeneity found in the formation. The significant heterogeneity of the formation is confirmed with pictures of core sections taken at the Joslyn project for Clearwater formation, shown in Figure 6-3. Some zones show well-cemented material, while others show highly interbedded rock where it is difficult to maintain the cores' integrity.

Figure 6-3 Photos of Clearwater Formation cores from Joslyn's thermal project. Taken from (Energy Resources Conservation Board, 2010)

6.5.1 Volume of shale in the caprock

The natural radioactivity of rocks is commonly used to identify lithologies. Different radioactive isotopes as potassium, thorium, uranium, and radium can be found in rocks. Clay minerals are rich in potassium, and thus, high radioactivity measurements are associated with clay, while low gamma-ray is associated with sand.

Considering the heterogeneity that is commonly found in rocks, a parameter that describes shale content is used to identify different lithologies in reservoir evaluation. There are different ways to calculate the volume of shale based on gamma-ray logs, and equation 6-1 corresponds to a linear correlation that converts gamma-ray measurements into shale volume (Bassiouni, 1994). The equation takes into account the relative maximum and minimum values of gamma-ray measurements for rocks in the studied area. Using equation 6-1, a profile of shale content can be obtained for every well of the project and this information could be used to populate the geomodel.

$$V_{\mathrm{sh}} = \frac{GR - GR_{\min}}{GR_{\max} - GR_{\min}} \qquad \text{6-1}$$

where

V_{sh}: volume of shale

GR: gamma-ray measurement from log

GR_{max}: maximum gamma-ray measurement from wells in the area of interest

GR_{min}: minimum gamma-ray measurement from well in the area of interest

The shale content presented in equation 6-1 is calculated for all the wells in the studied area of Pad AE from MRCP. With the newly generated log, the distribution of shale content can be analyzed at every formation as presented in Figure 6-4. The results show that Clearwater follows a normal distribution, and this distribution is the result of having Upper Clearwater and Lower Clearwater in the same statistical analysis. McMurray formation exhibits a low clay content in general, with some exceptions that correspond to mud channels within the reservoir. Finally, Wabiskaw is tough to analyze in terms of clay content since the distribution is spread, which means that the formation is composed of different minerals in similar proportions. Shale content statistical results are in good agreement with the facies distribution obtained in CHAPTER 4 and the geological characterization of the formation (Hein, 2015)

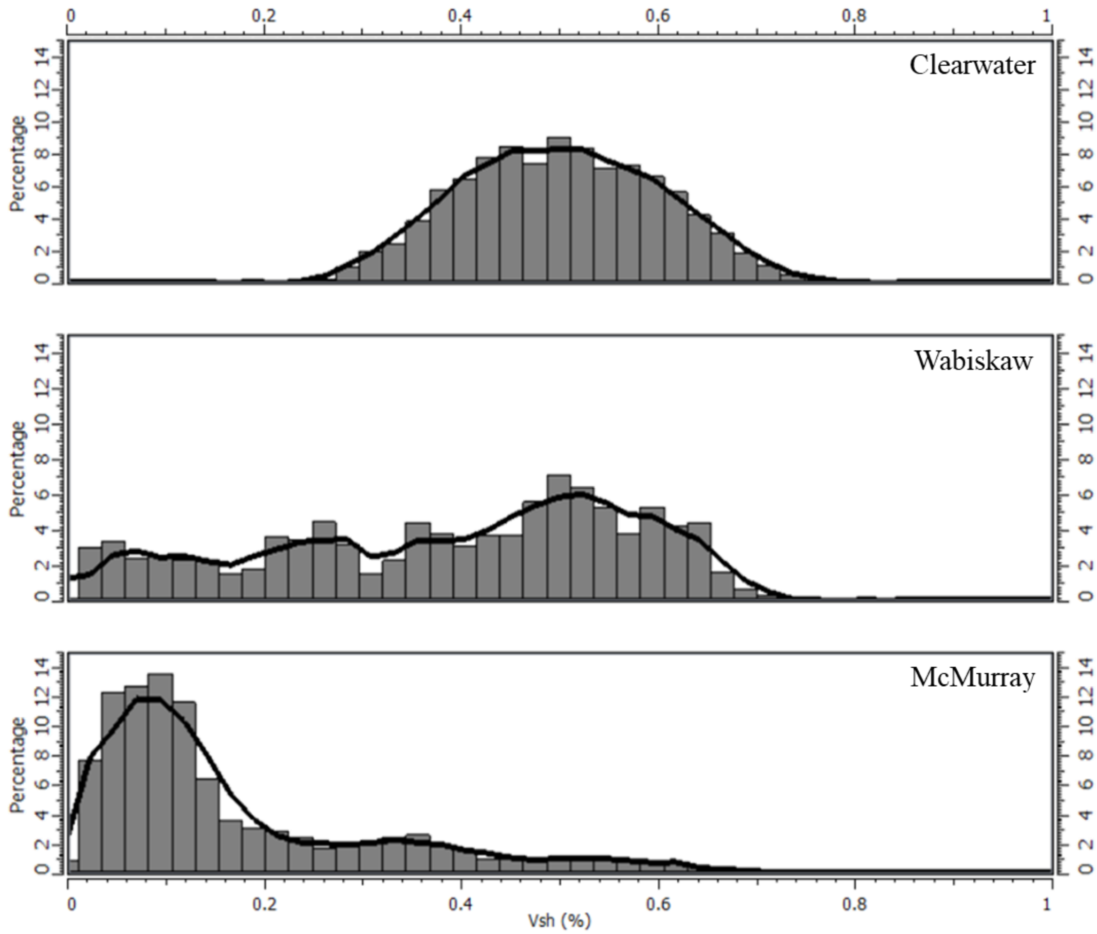


Figure 6-4 Volume of shale distribution for Clearwater, Wabiskaw and McMurray formation.

6.5.2 Caprock Quality Index calculation

As mentioned above, clay content and formation thickness are key factors for a caprock to be able to assure reservoir containment. Caprock Quality Index (CQI) is a concept that includes both factors in a single parameter. This index facilitates an initial risk assessment from geological information and could be obtained quickly to help design monitoring programs. It could also be used to identify regions where safety can be a concern to implement numerical simulation for further investigation.

The index is initially calculated at every grid-cell of the geomodel by multiplying the shale's volume and thickness. Subsequently, an arithmetic average is calculated following equation 6-2, which allows having a single value for a coordinate point that can be presented as a map. This presentation aims to identify points of concern where a failure can be initiated and propagated during thermal recovery.

$$CQI = \frac{1}{n}\sum_{i=1}^{n} V_{\mathrm{sh}i} * h_i \qquad 6\text{-}2$$

where:

CQI: Caprock Quality Index

V_{sh}: volume of shale

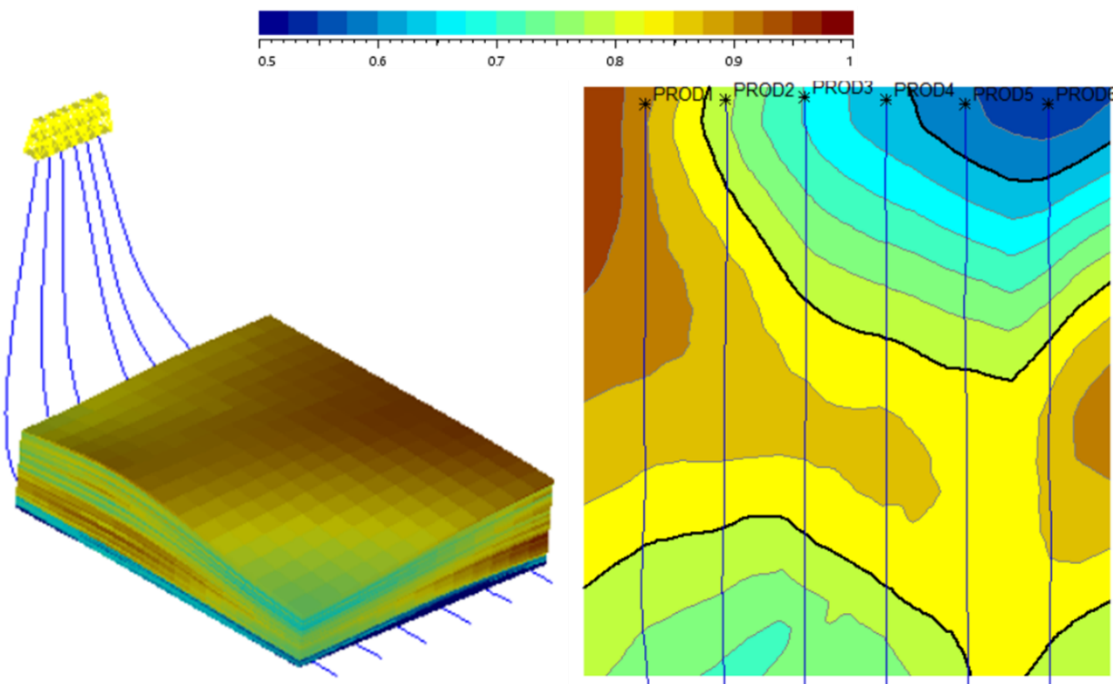
h: layer thickness.

n: total number of layers in the caprock

Since CQI is calculated at every cell of the geomodel, multiple analyses can be done as vertical and horizontal variability as well as the variability at different caprock layers. Figure 6-5 a) shows the CQI in the caprock. The results suggest that the quality of caprock is higher at Lower Clearwater than at Upper Clearwater; this is in good agreement with the definition of Clearwater argillaceous that is commonly found in the geological descriptions of the formation (Huag et al., 2014). At the base of the caprock, the CQI is very low, which corresponds to Wabiskaw Sand.

On the other hand, an aerial view of CQI allows to visually identify the regions where the CQI is low, as presented in Figure 6-5 b). Figure 6-5 b) illustrates the arithmetic average of CQI for the whole formation. Even though this plot does not capture details of the different sections of the caprock, it identifies regions where the formation is competent to contain the reservoir's fluids. The case studied also exhibits low CQI at the toe of Well pairs 5 and 6, while the best quality is obtained at the top Well-pair 1.

The geological information gathered from seismic data, well logs, and experimental results, only represent a limited part of the caprock. Thus, uncertainties inevitably exist during the measuring process, geological interpretation, and geostatistical modeling. Sufficient realizations with different distributions of facies and properties are created to quantify these uncertainties. The quick estimation method proposed here can quickly utilize these realizations and provide valuable statistical assessments for the project design and monitoring plan without running time-consuming coupled reservoir-geomechanical simulations.



a) b)

Figure 6-5 Caprock Quality Index (CQI) for PAD AE at MRCP. a) 3D model of caprock with CQI for each cell. b) Aerial CQI map.

6.6 Reservoir Quality Index RQI

Reservoir Quality Index is a concept used in reservoir engineering and helps identify the sweet spots for future drilling and planning field development. The definition of the concept can vary depending on different conditions as the type of reservoir or recovery method (Al-Rbeawi & Kadhim, 2017; Onuh, David, & Onuh, 2017). It is usually based on petrophysical properties such as permeability, porosity, and oil saturation, which are used to determine the regions with high reserves within the reservoir. In this case, a simple model is used to identify the places where the steam chamber is expected to grow significantly vertically within the reservoir.

Two properties are used to calculate RQI, vertical permeability, and reservoir thickness. Fluid saturations are not included in the proposed method because the chamber growth is not limited by fluid saturation but by permeability. Equation 6-3 is used to calculate RQI for every grid-cell, and then it can be integrated to estimate the average RQI at any geographical coordinate

$$RQI = \frac{1}{n}\sum_{i=1}^{n} k_{vi} * h_i \qquad 6\text{-}3$$

Where:

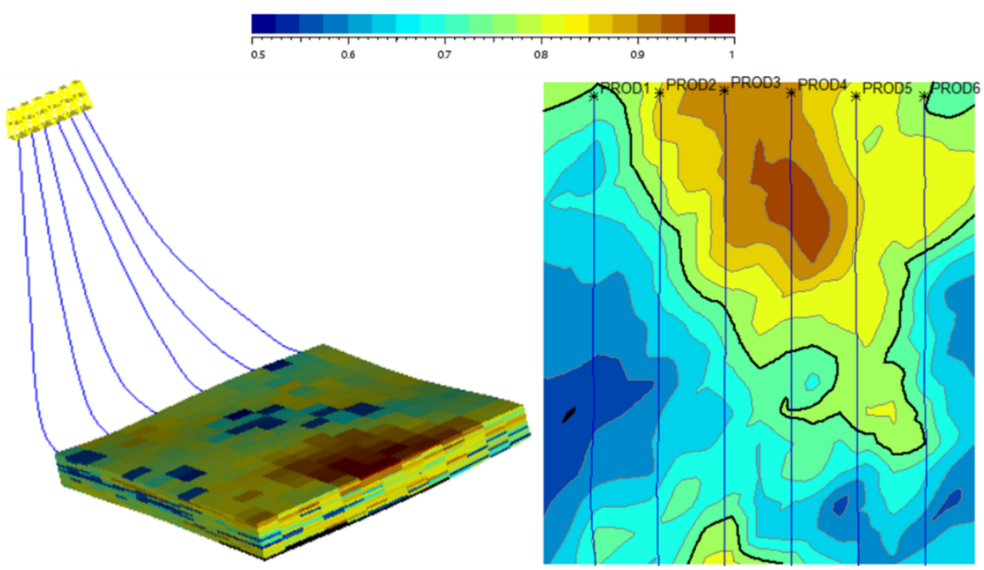
RQI: Reservoir Quality Index

k_v: vertical permeability

h: layer thickness.

n: total number of layers in the reservoir

Similar to CQI, RQI can be analyzed for every part of the reservoir. Figure 6-6 a) illustrates the estimated RQI in the geomodel created for Pad AE at MRCP. Due to the lateral continuity of the formation, RQI is mainly affected by the permeability of the area. Thus, the low permeability region or mud bodies within the reservoir significantly affects the RQI estimation. Additionally, Figure 6-6 b) illustrates the average RQI obtained for the area where a good quality reservoir can be identified. Regions where RQI is high, as the toes of Well-pairs 3 and 4, correspond to regions where the steam chamber is expected to grow quickly and become large.



a) b)

Figure 6-6 Reservoir Quality Index (CQI) for PAD AE at MRCP. a) 3D model of caprock with RQI for each cell. b) Aerial RQI map

6.7 Reservoir containment Risk Index

Reservoir containment is lost when thermal operations cause caprock failure. As mentioned above, caprock failure occurs when the applied load overcomes the strength of the caprock, analogous to the safety factor definition. Reservoir Quality Index (RQI) helps to evaluate the load that could be applied to the caprock as a result of steam chamber growth in the vertical direction, while Caprock Quality Index (CQI) represents the strength of the caprock. Risk Index RI is a parameter that combines RQI and CQI to identify regions of safety concern for reservoir containment loss. Hence, the risk of reservoir containment loss is directly proportional to the steam chamber size and inversely proportional to the strength of the caprock. Thus, if the steam chamber grows fast but the caprock is strong enough, the operation does not represent high-risk levels. In contrast, when the steam chamber grows fast and the caprock is not strong enough at the same location, a failure can be initiated and propagated, leading to containment loss.

Equation 6-4 can be used to calculate the RI using RQI and CQI. Then, RI is normalized using equation 6-5 to keep the result between 0 and 1. Low RI values correspond to areas where the caprock is safe, while high RI represents regions where risk is relatively high within the area.

$$RI = \frac{RQI}{CQI} \qquad \text{6-4}$$

$$\overline{RI} = \frac{RI}{RI_{\max}} \qquad \text{6-5}$$

RI can be used to answer questions fast, like where to run a geomechanical simulation or where further characterization is needed. Additionally, following the Systematic Approach proposed in CHAPTER 3, RI can be used as a criterion to identify critical locations to be monitored. The main advantage of using RI for monitoring is that it involves both reservoir and caprock properties, which increases the value of the information since it could be used not only to assure safety but also to evaluate reservoir performance during the operation.

Even though caprock quality and reservoir quality are known, it is the combination of both what really helps identify risky regions in the area. Figure 6-7 presents the maps obtained previously for RQI and CQI and the map obtained from calculating RI. The results demonstrate that both RQI and CQI have a significant impact on the Risk Index. At some places where CQI does not change much, as in the middle of the pad, RI is highly impacted by RQI. On the other hand, in places where CQI is low as the toe of Well-pair 6, RI is high despite the low value of RQI. This means that even if the steam chamber is not expected to be large, the risk can be relatively high due to the quality of the caprock. Finally, the results are in good agreement with the results obtained from numerical simulation, where high vertical displacement was predicted for Well pairs 4 and 5 toes.

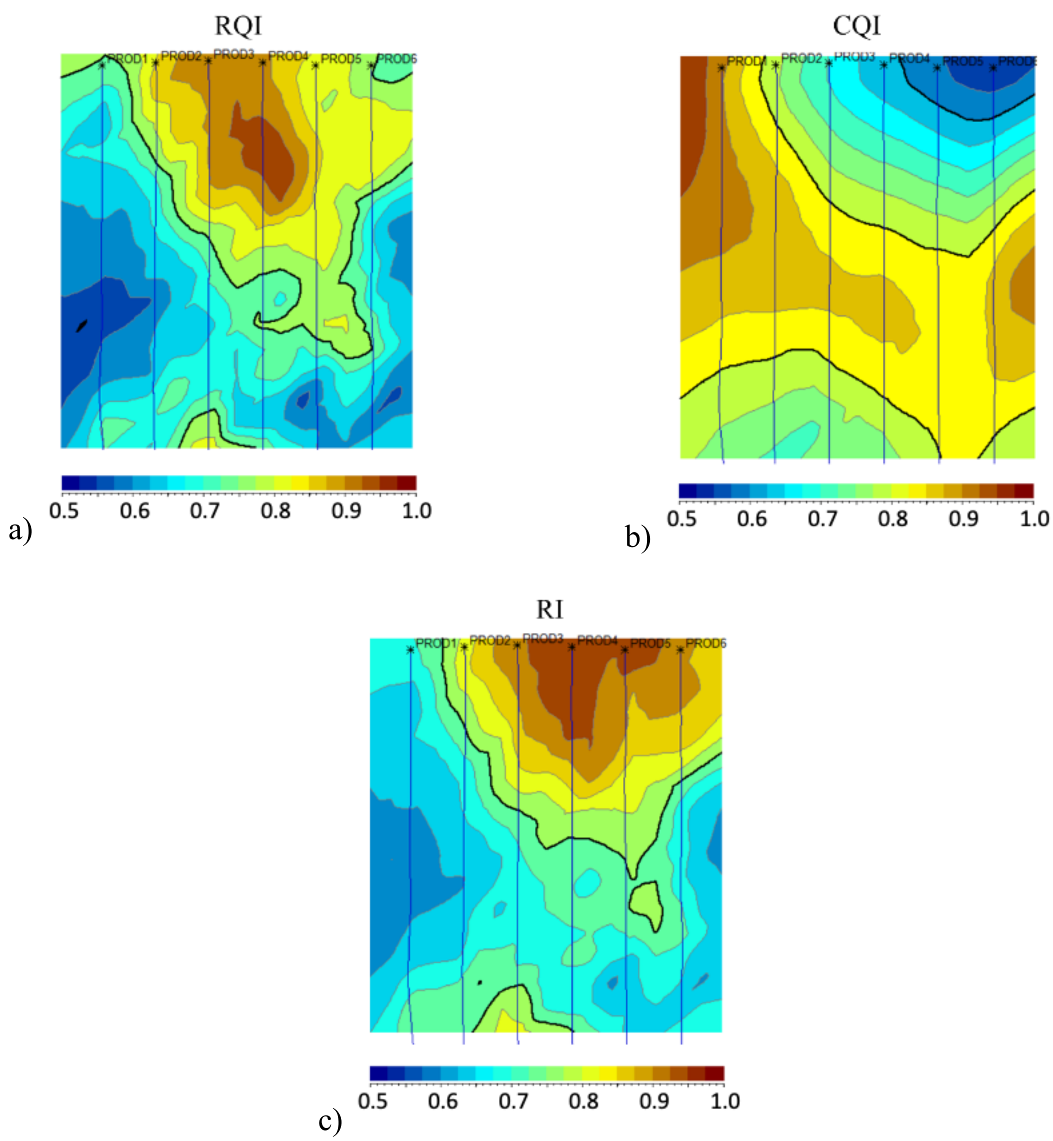


Figure 6-7 Aerial view of a) Reservoir Quality Index, b) Caprock Quality Index and c) normalized Risk Index

6.7.1 Joslyn Creek Case Study

Risk Index can be used to help select instrument locations or areas of safety concern within a study area. Figure 6-8 shows the results for RQI, CQI, and RI at the Joslyn Creek project. In this case, the whole development area is analyzed to identify the most challenging areas for reservoir containment safety. According to AER's definition, Joslyn Creek has been the shallowest SAGD project of the world; the reservoir depth is as low as 40 meters in some areas. Also, as explained earlier, Joslyn is the largest reservoir containment incident in in-situ projects in Alberta to date. It occurred when SAGD stage started for Pad 204 in 2006.

Pad 204 and pilot Well-pairs are also included in the maps to identify the incident's location. The results suggest that around Pad 204 Reservoir Quality Index is higher than the rest of the project. On the other hand, Caprock Quality Index is low in the middle of the Well-pairs. These two conditions facilitate the development of caprock failure, as the Risk Index value illustrates. RI presents high values in the middle of the pad, according to the map. This means that if operating at risky conditions, the caprock is likely to fail around this area. Joslyn's blowout occurs at the east of the pad above Well-pair 1. Thus, Risk Index calculation can predict areas of concern for reservoir containment. Khani (2022) identified the areas above Well-pair 3 as a safety concern where failure was likely to develop; nevertheless, the crater location was given by the existence of an abandoned well with a poor cement job. The results demonstrate that for Joslyn Creek project, Risk Index calculation is able to identify potential areas of safety concern where instrumentation placement could have been of significant help to identify the conditions that led to the steam release event.

Risk Index is a static value based on geology and it does not consider information as abandoned wellbores or operating conditions. Therefore, the results from RI maps need to be complemented with such information to identify critical areas. RI values are not intended to be used as the final criteria for selecting instruments' location; they are intended to be used as input parameters to guide the strategical monitoring design.

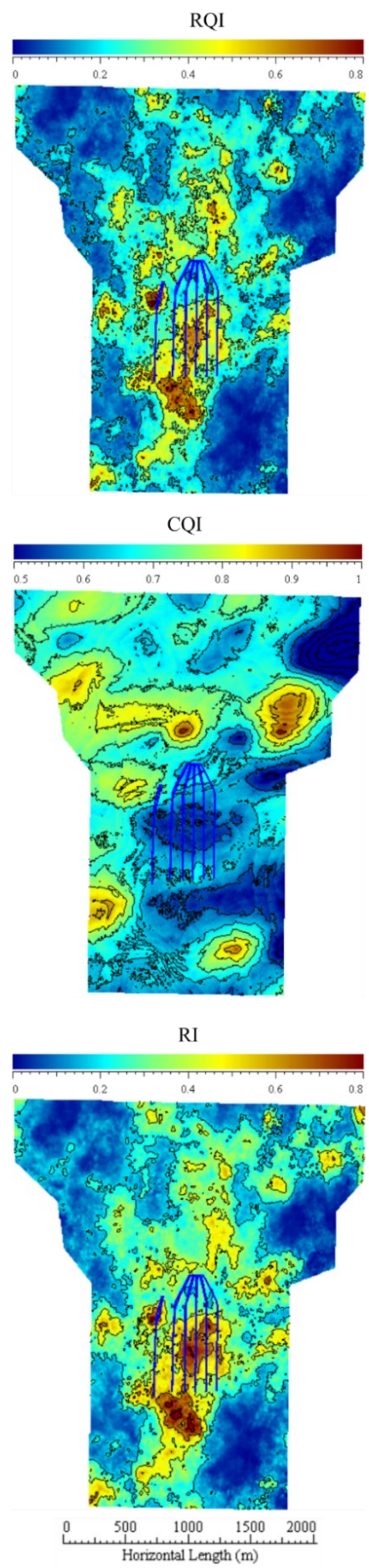


Figure 6-8 Aerial view of Reservoir Quality Index, Caprock Quality Index and normalized Risk Index for Joslyn Creek project

CHAPTER 7 CASE STUDY- JOSLYN POST FAILURE MONITORING

7.1 Introduction

After Joslyn's incident in May 2006, Total Energy decided to restart the project in February 2007 using lower injection pressures to prevent further issues. The operations were accompanied by an ambitious monitoring program increasing the protection layers for reservoir containment risk management. The project continued for several months until the new regulation was released, and the injection pressure had to be dropped to values that affected the economics of the project significantly.

The project's information was shared with the University of Alberta to be used in research leading to a broader understanding of subsurface behavior in shallow reservoirs during SAGD operations. For the project restart, the geomechanical monitoring program used at the blowout's pad included different ground deformation measurement techniques. This program has been one of the most acquisitive monitoring programs in Alberta for thermal operations.

This amount of information offers a unique opportunity to advance knowledge related to SAGD monitoring since different technologies can be compared as well as factors that affect measurements. This chapter presents an analysis of the information obtained from the different instruments used in the program. The results are compared to each other in order to identify their advantages and disadvantages. High-resolution geological model and sequential coupled simulation, similarly to CHAPTER 4 and CHAPTER 5, are also used to history match production and displacement and identify the critical locations that should be monitored. Additionally, the value of information obtained by instruments is analyzed to demonstrate how the procedure followed by this research can lead to an optimal monitoring program reducing the associated costs without affecting the safety of the operation. Finally, the methodology proposed in CHAPTER 6 is used to identify critical safety regions throughout the project's area for instruments' location.

7.2 Post-failure monitoring program

In February 2007, Total Energy restarted Pad 204 in the Joslyn Creek SAGD project. Two well pairs were shut-in completely, Well-pair 1 (where the crater was generated and Well-pair 2 (closest Well-pair). The remaining well-pairs of the pad and the pilot well-pair of the project were restarted and operated at different pressures until April 2009. The injection pressures used were below the pressure used in the initial stage in order to prevent a second blowout.

This phase was accompanied by robust geomechanical monitoring that included measurement of displacement using different devices such as tiltmeters, InSAR, and D-GPS. During the geomechanical monitoring program, 136 tiltmeters, 95 corner reflectors, and 35 D-GPS sensors were installed in the pad area. The location of the sensors was concentrated at the wellheads and heels of the operating Well-pairs, as presented in Figure 7-1. Some corner reflectors were installed outside the pad area to be used as a benchmark for the measurements. On the other hand, the D-GPS sensors were located equidistantly along the horizontal section of the Well-pairs.

Corner reflectors were installed at two different times of the project to evaluate the impact of pillar burial depth on the measurement accuracy. The first 65 corner reflectors were installed at the beginning of this second phase using short pillars (5 meters), and the remaining 30 were installed one year later using longer pillars (7 meters). Short pillars are referred to in this work as InSAR_1, while the deeper pillar CRs are referred to as InSAR_2, as illustrated in Figure 7-1.

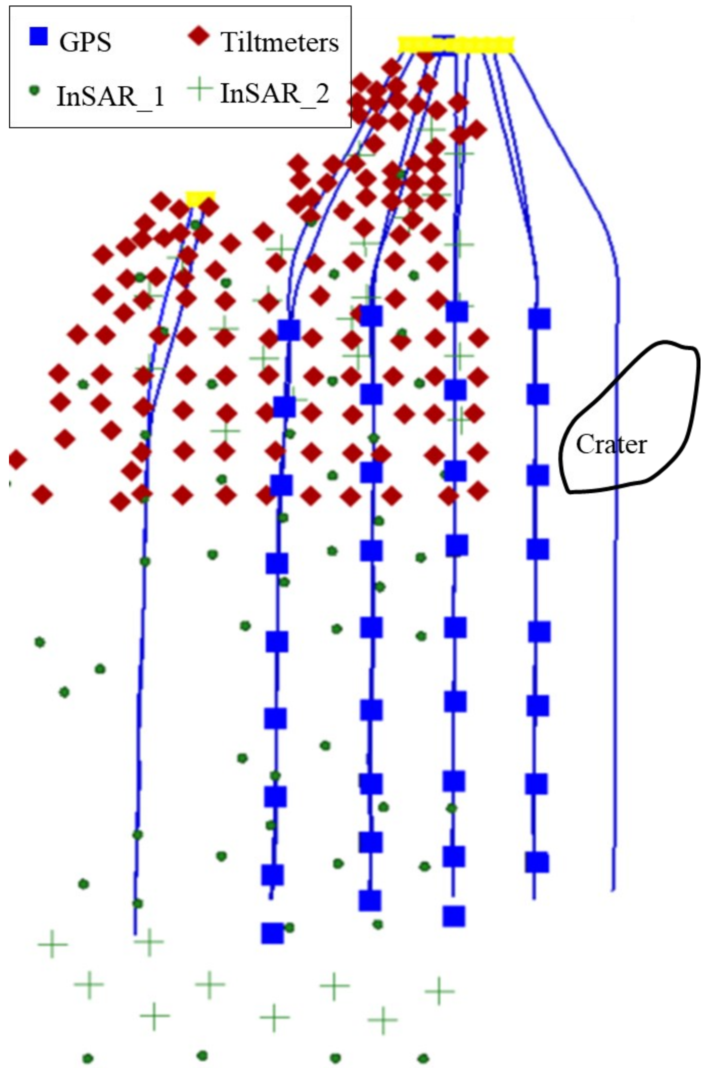


Figure 7-1 Heave monitoring instruments at Pad 204 Joslyn's SAGD Project after the 2006 blowout

7.3 Surface heave measurements

7.3.1 Effects of weather on ground deformation measurements

As mentioned above, two different generations of corner reflectors were used in the project. The difference between both generations was the length of the pillars used to install the corner reflectors. The second generation was installed to increase the density of the measurement point and evaluate the effect of external factors that could affect the measurements as weather and road traffic. One meter of the pillar was left above the ground, and the rest was buried in such a way that the pillars were buried 4 and 6 meters for the first and second generation, respectively.

The resulting measurements show a considerable impact of weather on the short pillars. Figure 7-2 illustrates the measurements taken at two nearly identical locations using corner reflectors from the different generations and the temperature registered at the Fort McMurray area over the monitoring time. The results demonstrate that even a small difference of two meters on the pillar length significantly impacts the measurements. Measurements taken from the corner reflectors installed on the shallow pillar are significantly affected at the beginning of the spring season when the water saturating the soil is melted. Water melting is accompanied by a change in volume that affects the structure of the upper soil. In contrast, the corner reflectors that use deeper pillars are slightly affected by temperature changes in the area. This means that the measurements taken from the first generation of InSAR are considerably affected by external factors as weather which reduces the accuracy and, consequently, the reliability of the measured values.

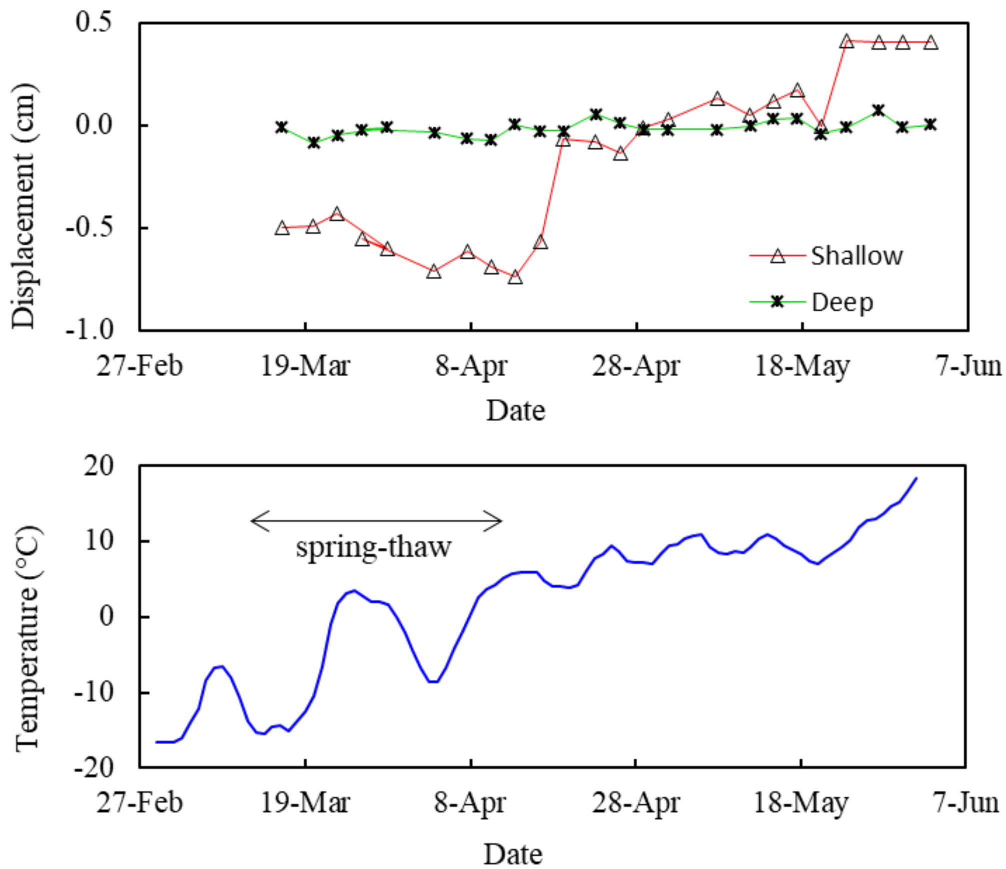


Figure 7-2 Impact of weather on corner reflector measurements.

7.3.2 Comparison of different instruments for heave measurements

The monitoring program included three different monitoring techniques to measure surface heave: InSAR, D-GPS, and tiltmeters. In addition, measurements obtained from InSAR are divided into two different sets of data based on the impact of the weather, since weather causes a considerable discrepancy of measurements, as explained above.

Figure 7-3 illustrates the contour maps for vertical displacement 20 months after the project restart; the maps are obtained from various instrumentation devices used in the monitoring program. The results from the different instrumentation show a similar spatial behavior where the maximum vertical deformation is measured at the middle of Well-pair 4. Nevertheless, the magnitude of the displacements measured by the different instruments varies considerably. The difference can be explained by the different external factors that affect the measurements since some instruments are more sensitive than others, as explained above for InSAR and tiltmeter measurements.

In addition, it is observed that the maximum vertical displacements measured by all the different techniques at the surface are located at a similar latitude to the crater generated by the steam release in 2006. These results suggest that this area might be a safety concern for reservoir containment since it exhibits more vertical displacement than the surroundings. These results are later compared with numerical simulation results and geological information to identify the cause of the large displacements at the specific area of the pad.

Even though Figure 7-3 displays the similarity of the measurements obtained using different technologies, it is limited to one specific time of the project (20 months). Figure 7-4 illustrates the behavior of sensors from different monitoring techniques located near each other over time. The instruments selected correspond to the instruments that registered the highest value for each technique, and the location of the selected instruments is illustrated in the frame inside the plot. The location of the instruments with the highest measured values confirms the area of maximum displacement in the pad. Moreover, when analyzing the behavior of the observations with time (Figure 7-4) a similar trend is observed from the different types of instruments that suggest they are capable of capturing the displacement generated by the expansion of the subsurface, but the accuracy changes considerably for each technique.

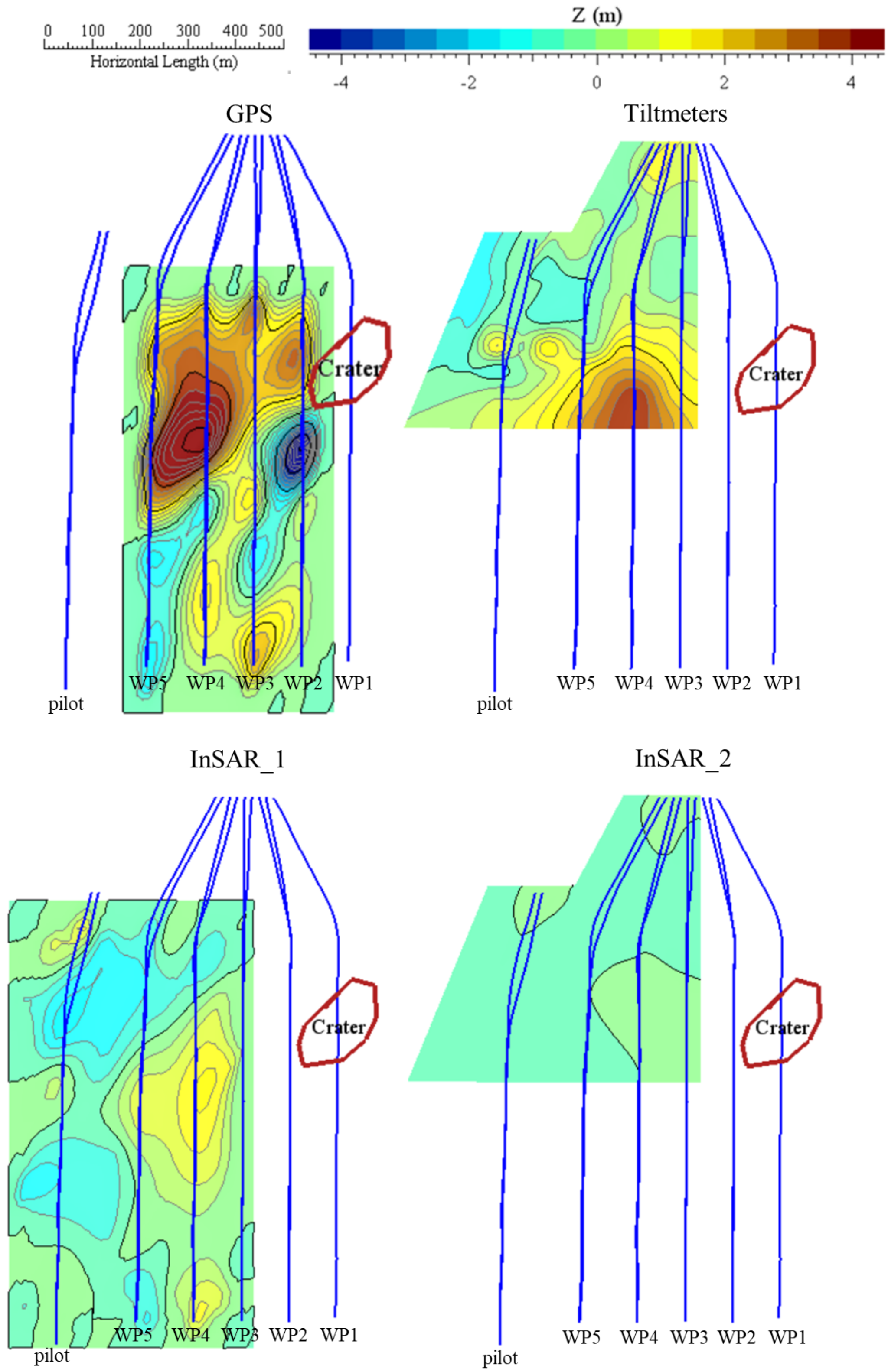


Figure 7-3 Vertical displacement measurements taken by different technologies 20 months after the project restart

One of the factors that govern the behavior of the measurements over time is the frequency of measurement. D-GPS measurements are reported every two weeks, resulting in more fluctuation of the curve, while more frequent observations as InSAR, reported every five days, and tiltmeters, reported daily, show smoother behavior of the recorded data. In addition, the high fluctuation of measurements taken from D-GPS evidence the low precision of this technique. In contrast, tiltmeters and InSAR measurements have good precision, but measurements can be significantly affected by external factors such as weather, traffic, and construction, to name a few. Figure 7-4 shows that tiltmeters exhibit a constant slope through the analyzed time; nonetheless, there is a sudden jump after 1400 days that could have been caused by external factors. Once the measurements are stabilized, it continues increasing with a similar slope.

It is difficult to certainly comment about the accuracy of the instruments since the true values are unknown, and the discrepancy of measurements from two different techniques can be as high as 300%. Nevertheless, the measurements recorded by the tiltmeters and D-GPS present similar values. Measurements from tiltmeters and InSAR_1 exhibit a similar slope from 1500 to 1700 days. These results suggest that even though the used devices cannot measure the absolute vertical displacement at the surface, the recorded values can be valuable to analyze the displacement rate caused by steam injection.

Furthermore, to understand how surface heave reflects subsurface phenomena, Figure 7-5 shows the behavior of surface heave measured by the different technologies and the injection pressure behavior at the Well-pair that is located right below the sensors. It can be seen in Figure 7-5 that the injection pressure takes some time to ramp up at the beginning of the injection and is followed by a plateau. Figure 7-5shows that all sensors except D-GPS are able to capture the initial change in pressure changing the displacement rate. InSAR_1 measurements show a steep change at the beginning followed by a constant slope while the pressure presents the plateau. Additionally, InSAR_1 is able to capture the end of injection by reducing the slope and reaching a constant value. Even though InSAR_1 is affected by season change as demonstrated in Figure 7-2, it can capture changes in the injection program since the actual displacement is likely higher than the values generated by weather changes.

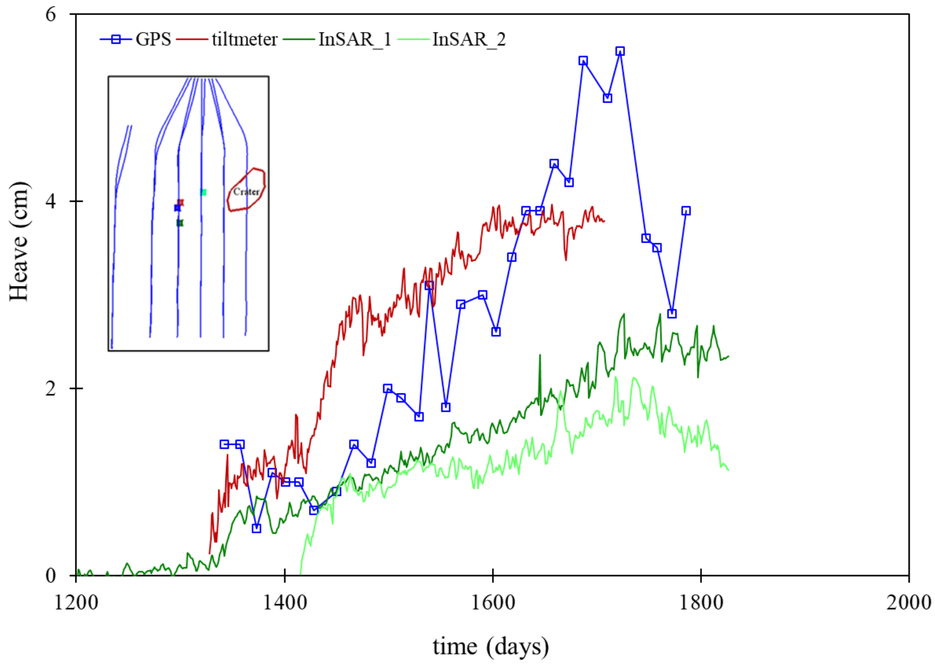


Figure 7-4 Comparison of measurements over time taken by different technologies located close to each other.

Moreover, tiltmeters also have a steady increase with a constant slope when injection pressure is constant. In addition, they could capture the instantaneous pressure decrease that occurred before 1600 days. Figure 7-5 illustrates how the tiltmeters curve decreases when injection stops; similar results have been observed in CSS during the injection and production cycles reflecting subsurface's elastic response trying to recover the initial position once steam injection is stopped. Finally, D-GPS behavior also approximates to a straight line when injection pressure is constant, but the measurements' low precision does not allow to establish a clear trend. The available monitoring data from the Joslyn project was taken while the steam chambers were still immature. Nevertheless, the results are similar to predictions obtained from numerical simulation presented in Figure 5-29, where there is a high displacement rate at the beginning of the SAGD phase followed by a reduction of the slope once the chambers start to expand laterally into the reservoir. This change in displacement rate is the result of the initial vertical growth of steam chambers in SAGD projects that increase the applied load to all the formations above.

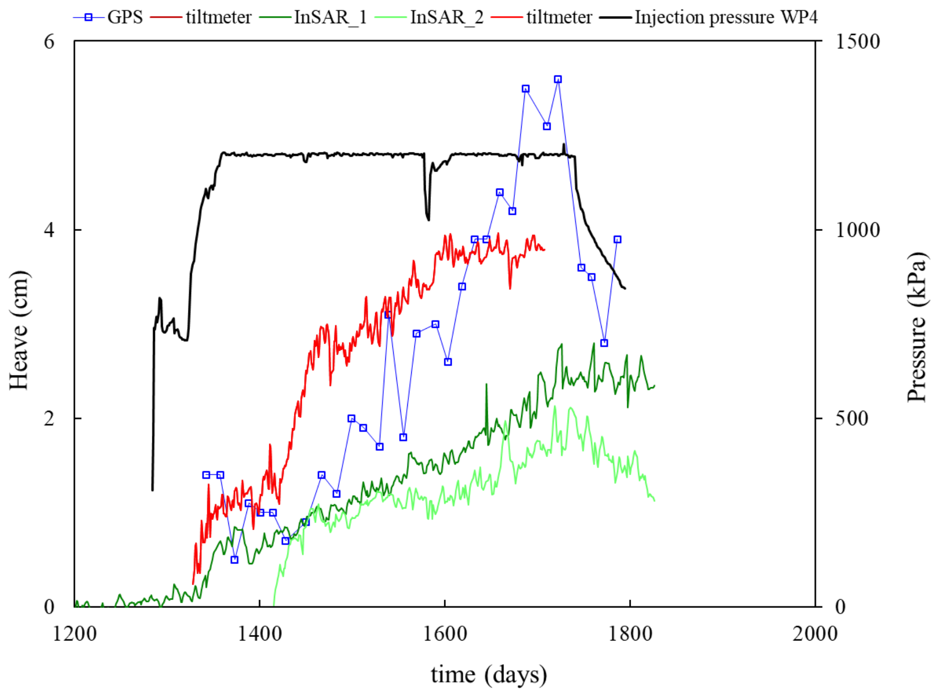


Figure 7-5 Injection pressure variation and surface heave observations from different monitoring techniques

7.4 Value of Information of tiltmeters measurements

Frequently, justifying the cost associated with monitoring programs becomes a difficult task. Therefore, understanding how the data collected can aid in decision-making analysis becomes crucial to spend resources in monitoring. Moreover, when the monitoring program is not designed appropriately, it ends up being costly and inefficient. As explained in CHAPTER 3, an appropriate monitoring program design should carefully and strategically select each instrument's location based on engineering judgment that ensures the value of information (VOI) of observations and the application to improve the processes.

In total, 135 tiltmeters were used to monitor the surface heave during 20 months after the 2006 steam release in Pad 204. The tiltmeters were installed at the heel and build-up section of Well-pairs 3, 4, 5, and Pilot. The information obtained from the tiltmeters is used to analyze the value of the information delivered by each of the sensors and to evaluate the minimum number of tiltmeters that are required to attain such information. This information is decisive for monitoring design since it can help to reduce the costs significantly, having a large number of instruments does not necessarily mean having better or more valuable information.

The analysis is performed by gradually reducing the number of tiltmeters from 136 to 4 maintaining the same covered area. The reduction was made by randomly eliminating the number of tiltmeters until achieving the minimum number (4). In all the steps, the remaining tiltmeters are located in a way that the covered area is constant, but the sensor density is reduced. The number of sensors is reduced by half and contours maps are generated at each step. Thus, contour maps are generated using the reading from 135, 67, 34, 17, 9, and 4 tiltmeters allowing to analyze the discrepancies of the displacement maps when the number of sensors is reduced. Figure 7-6 illustrates the location of the sensors after each reduction process.

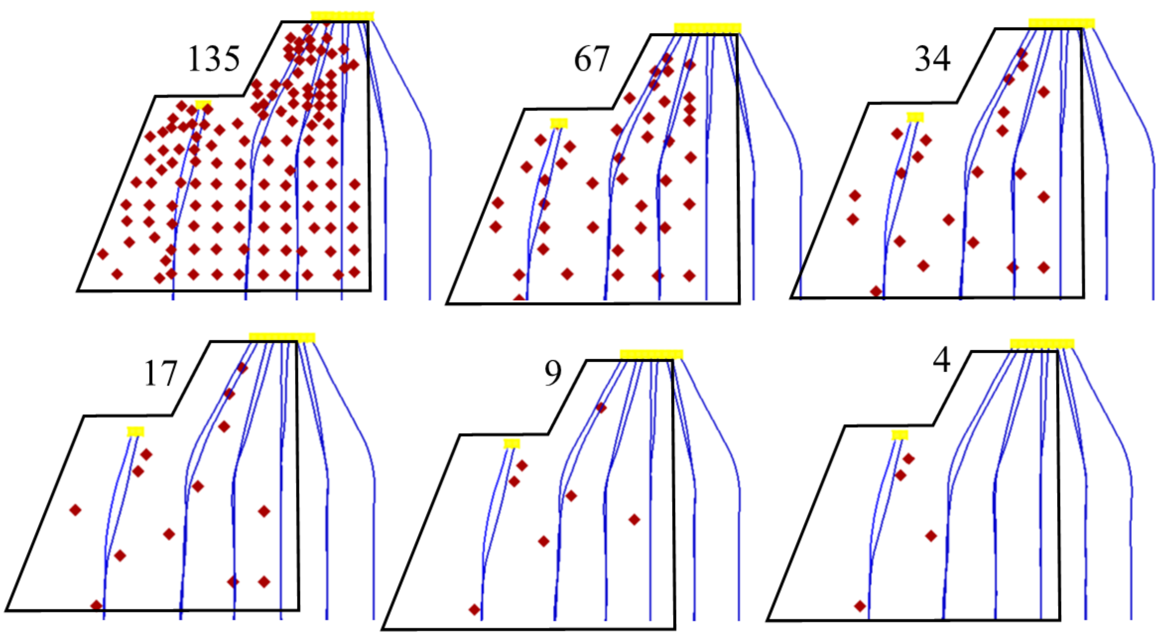


Figure 7-6 Reduced tiltmeters locations in Pad 204 Joslyn Creek Project.

Contour maps obtained using different number of tiltmeters are presented in Figure 7-7. The results demonstrate that installing more sensors does not mean having better information. The analysis suggests that the number of tiltmeters can be reduced by 75%, from 135 to 34, without significantly affecting the interpretation. Even when the number of tiltmeters is reduced to 17 tiltmeters or 12.5% of the original number, the resulting map can capture the main changes in surface heave for the area. On the other hand, when the tiltmeters are reduced to 9, which is slightly more than 6% of initial number, the map is limited to capture surface heave details.

These results suggest that Joslyn Creek's tiltmeter monitoring program could have been optimized by placing just 12.5% of the actual installed tiltmeters without affecting the quality of the monitoring results. This improvement can be translated into savings of the project or a larger monitored area. However, the 17 remaining tiltmeters should be placed strategically to capture the larger displacements in the area to maintain data quality. According to the data interpretation from all the different monitoring techniques, the maximum heave was measured at the middle of Well-pair 4. Thus, more sensors and the acquired information within this region would have more value than sensors placed in other regions.

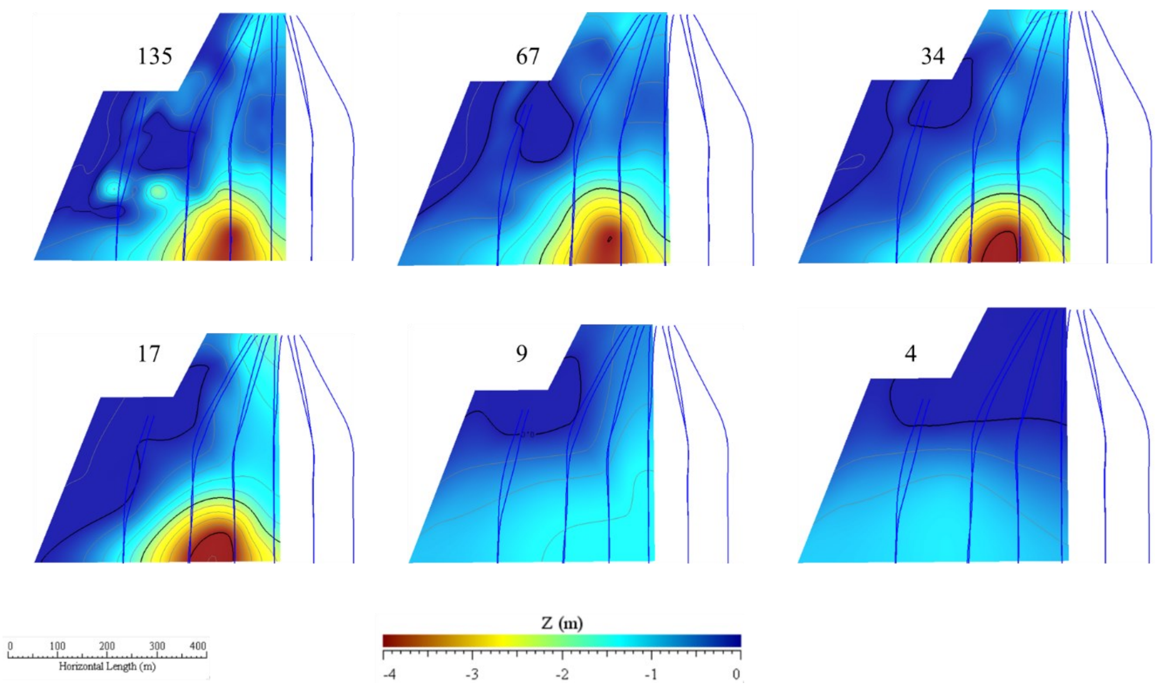


Figure 7-7 Vertical displacements contours from reduced tiltmeters

7.5 Numerical simulation

High-resolution sequential coupled simulations were run to follow the methodology proposed in this research in the case study. The static model was built following the same procedure explained in CHAPTER 4. A geocellular model for petrophysical properties was used for the reservoir region, and facies distributions of reservoir and caprock were obtained based on Gamma-Ray logs to populate geomechanical properties, as explained in CHAPTER 4. The model was then used for sequential numerical simulation similar to the results presented in CHAPTER 5 for the MacKay Commercial Project operated by Petro China Canada.

However, for Joslyn Creek's post-failure analyses, a production history match was included for the operating months to ensure the model reliably predicts reservoir performance and field observations, more information related to Joslyn’s geomechanical model can be found the Khani (2022). The results obtained from the matched numerical simulation are used to select the location of the surface heave sensors following the systematic approach explained in CHAPTER 3

7.5.1 Cumulative oil production history match

A history match for cumulative oil production was performed to guarantee that the flow model used in numerical simulations can reliably predict observed data. The history match included matching the cumulative oil production for the analyzed period of time for all the well-pairs as well as the total cumulative production of the pad. History match was obtained by changing the initial absolute permeability of the reservoir. Permeability was used to match results given the uncertainty of the procedures used to measure it in the laboratory. Permeability measurements are usually performed using reservoir cores that are severely affected by the extraction and handling processes, as explained by Dusseault (1980), where he observed that the samples' properties at the laboratory significantly differ from in-situ properties. Sample disturbance is mainly caused by the unconsolidated nature of the samples, stress relaxation, and the decrease in pore pressure that results in fluid expansion and gas release. Fluid expansion and gas release alters the sample's structure affecting petrophysical properties like porosity and permeability.

Even though the monitoring program of the pad started after the steam release in 2006, the simulation cases used for history match analysis are run from the beginning of the project in 2004. Simulating the whole process is crucial to obtain the total surface deformation; as demonstrated in CHAPTER 5, the surface heave is affected by operations in the vicinity of the studied area. The final oil cumulative production obtained from the calibrated permeability is presented in Figure 7-8. The simulation results suggest that the model was properly calibrated to represent the actual reservoir performance during SAGD and can be used in coupled simulation to evaluate the surface heave.

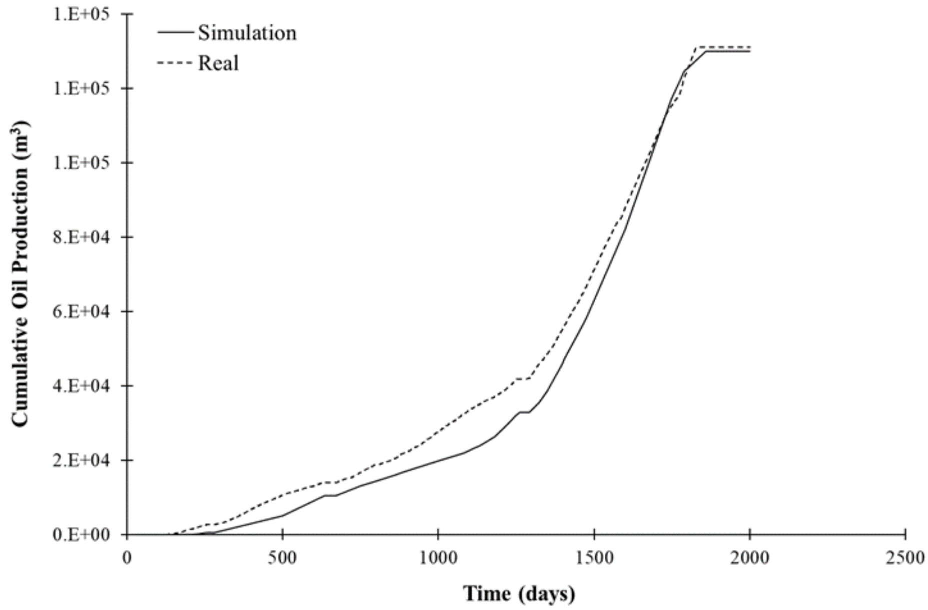
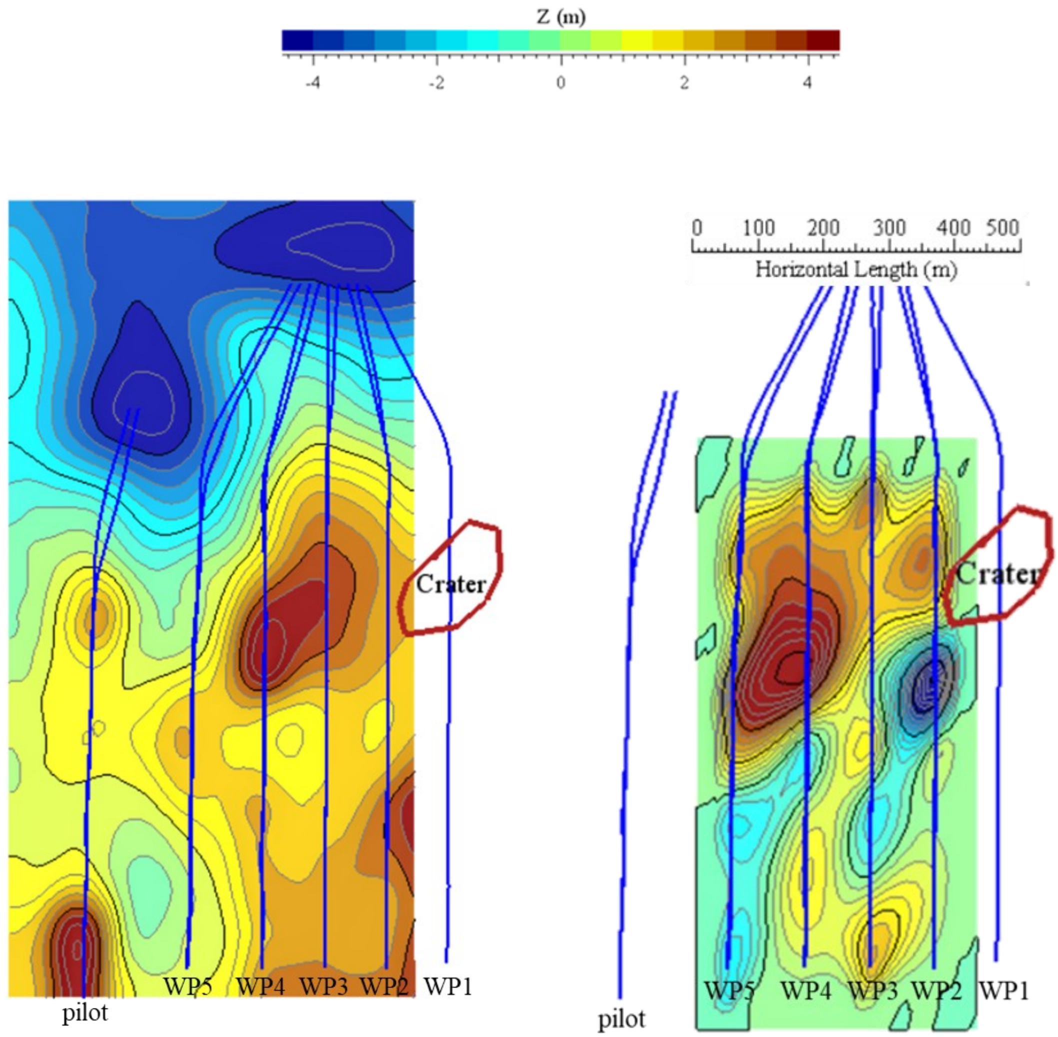


Figure 7-8 Cumulative Oil production history match for Pad 204 at Joslyn Project.

7.5.2 Surface heave predictions

After obtaining an acceptable match of simulated production and actual data, the geomechanical response is analyzed. Figure 7-9 illustrates the surface displacement obtained from simulation as well as the measurements recorded by D-GPS. The results show that numerical simulation results are in good agreement with the field observations. Moreover, simulation results could capture the region of highest heave in the middle of Well-pair 4, suggesting that the geomechanical model can be used to evaluate the response in the area. Thus, a geomechanical model that honors the field observation is crucial to predict the mechanisms that control the behavior and design an efficient monitoring program as per the Systematic Approach detailed in CHAPTER 3.

Furthermore, the numerical results of ground surface deformation are consistent with the other instruments' observations discussed in 7.3.2. According to the measurements taken by tiltmeters, InSAR, and D-GPS, the highest ground deformation also occurs in the vicinity of Well-pair 4 at a similar latitude to the '2006's blowout. The differences observed in surface heave spatially are mainly caused by subsurface heterogeneity, as explained in CHAPTER 5. Therefore, the results demonstrate that the geological model used for simulation captures the subsurface's heterogeneities that govern the field observations. These heterogeneities include the structure of the tops of the formations, low permeability zones within the reservoir and silt content in the caprock



a) b)

Figure 7-9 Surface heave, a) from numerical simulation, b) from D -GPS

7.6 Heave monitoring design based on simulation results

The magnitude of change of the monitored parameters should be predicted during the planning to select the most appropriate instrumentation and location according to the methodology proposed in CHAPTER 3 based on Dunnicliff's approach for monitoring geotechnical projects (Dunnicliff, 1988). In 7.4, it was demonstrated that tiltmeter locations could be significantly improved without compromising the quality of the information. The analysis in that section was performed by reducing the number of instruments using randomness instead of any engineering judgment. In this section, only four tiltmeters are strategically located based on numerical simulation results. The information obtained from these four instruments is then analyzed to evaluate how representative it is compared to the complete instruments.

Figure 7-10 a) shows the simulated vertical displacement at the ground surface for the whole model. The analyzed area is limited to where tiltmeters observations are available (see Figure 7-10 b). From the analyzed area, four points are selected where displacement exhibits the largest changes after 20 months. Subsequently, the observations from the closest tiltmeters to these points are used to obtain the corresponding displacement map. The resulting surface from the four selected tiltmeters is similar to the surface obtained using all the instruments (Figure 7-3). These results suggest that by selecting the appropriate instrument density and location based on numerical results, it was possible to capture most of the ground surface deformation of the studied area caused by SAGD operations for a lower cost.

The results demonstrate how powerful the Systematic Approach to Planning Monitoring Design can be to obtain a cost-effective monitoring plan. Selecting the locations based on simulation reduces the number of tiltmeters by 97%. In contrast, reducing the number of tiltmeters randomly still required a minimum of 17 tiltmeters to capture the ground deformation details. Therefore, using simulations results can help significantly to identify the most suitable locations to be monitored and the minimum number of instruments required.

In addition, numerical simulation can also be convenient to select the type of instruments to be used in monitoring programs since the magnitude of the predicted changes is essential to choose an appropriate monitoring technique based on the accuracy and precision required.

7.7 Heave monitoring design based on Risk Index

Even though numerical simulation is a powerful tool that can predict the subsurface's geomechanical response, as it has been widely demonstrated in this thesis, it requires many resources to be completed. Moreover, the model should capture subsurface heterogeneities and most of the physics involved in thermal recovery to obtain reliable predictions, requiring specialized personnel, time, and high-performance hardware. Hence, in CHAPTER 6, a methodology based on geological information that takes into account the heterogeneities was proposed to help identify locations for monitoring purposes. Moreover, the methodology uses reservoir and caprock properties to estimate a variable named Risk Index that aims to identify the areas that can be concerning for reservoir containment.

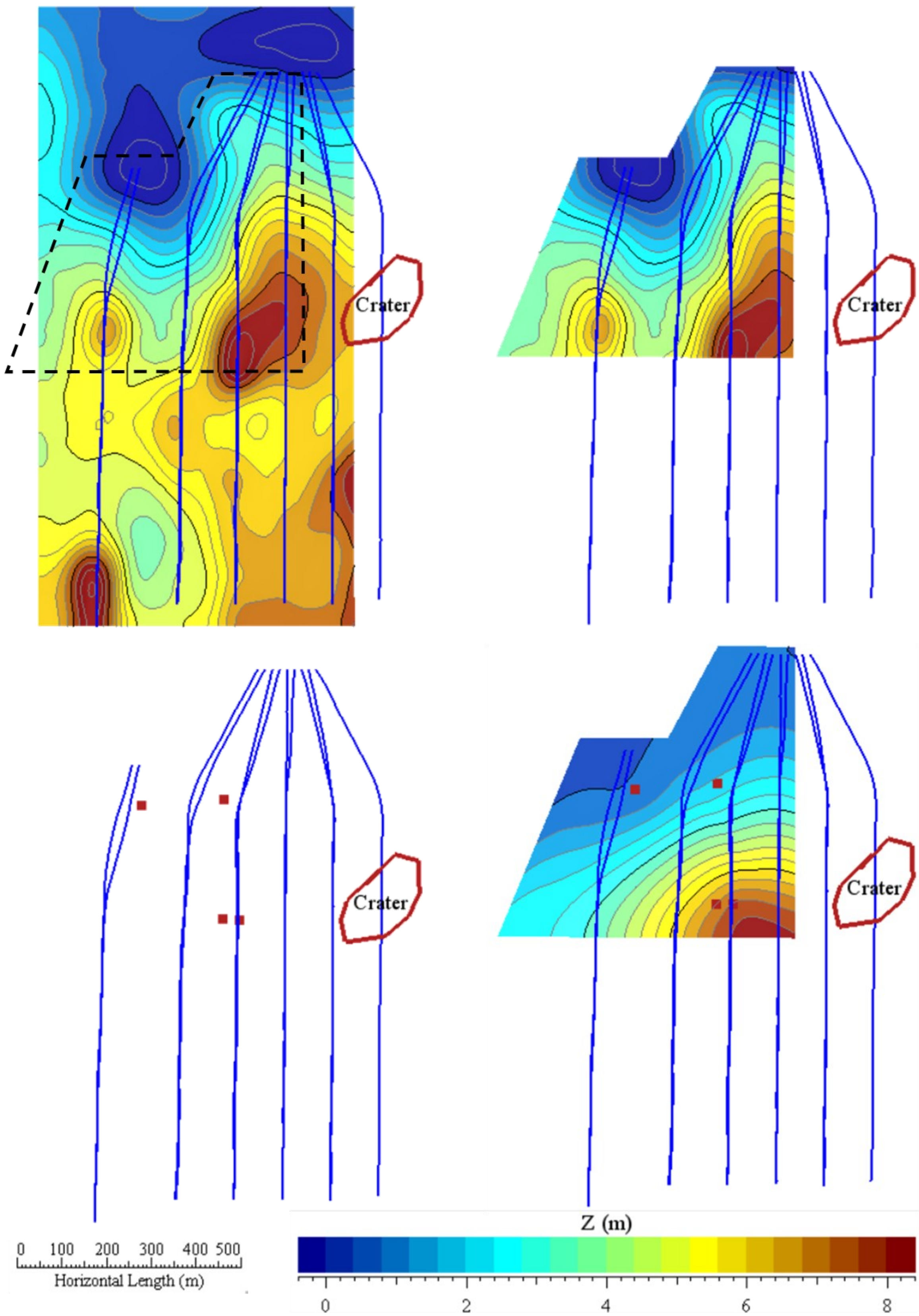


Figure 7-10 Surface deformation using tiltmeters selected from numerical simulation results

Similar to the procedure followed with simulation results, four tiltmeters were selected based on Risk Index values. Figure 7-11 shows the Risk Index map and the surface resulting from selecting tiltmeters in the areas where Risk Index was high. The results suggest that the Risk Index can be used with confidence to select appropriate instrument locations. Nevertheless, Risk Index is based just on geological information and not on operating conditions and the actual response of the subsurface. This assumption might result in some discrepancies. For instance, Figure 7-11 shows a high value of Risk Index close to the heel of the Pilot well-pair, this section of the wells is usually known as the "building section" that corresponds to the transition from vertical to horizontal sections. SAGD wellbores are completed in a way that production and injection occur at the horizontal section since it is the section directly connected to the reservoir. Therefore, even though this area can be identified as a high-risk area, there is no actual SAGD process at this point, resulting in low or negligible surface deformation measured by the instruments. Thus, the Risk Index is a powerful tool that can be used to plan a cost-effective monitoring program but still requires to be used with complementary information to ensure that the monitoring program is appropriate for the project conditions.

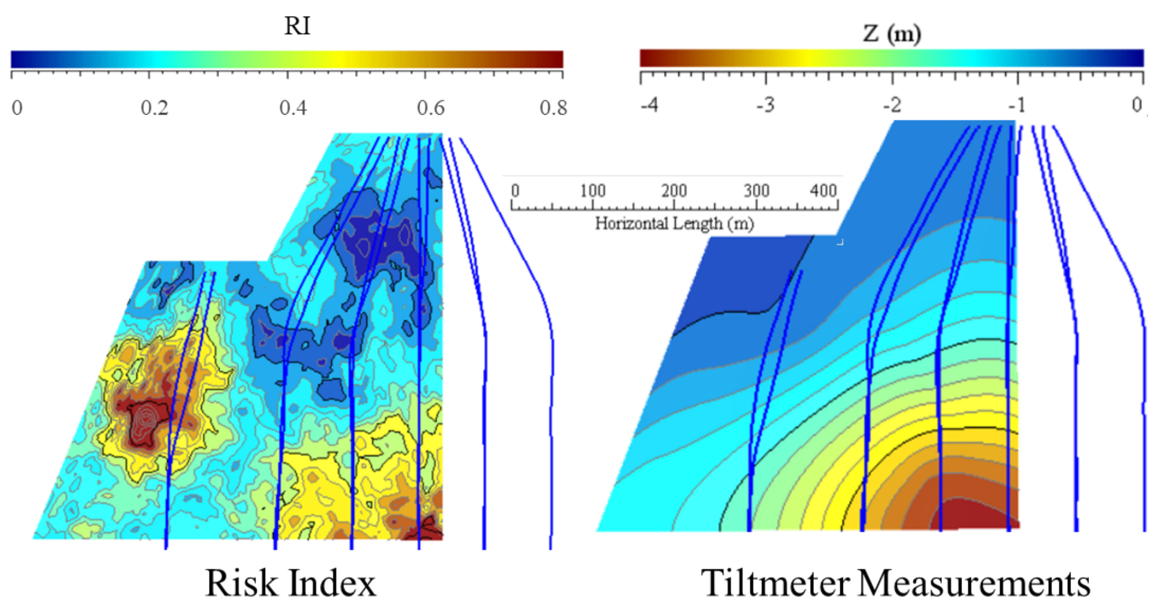


Figure 7-11 Surface deformation using tiltmeters selected from Risk Index calculation

CHAPTER 8 CONCLUSIONS AND RECOMMENDATIONS

8.1 Summary

Reservoir containment has become one of the main risks for in-situ thermal recovery in Alberta after some incidents in the last 15years. Therefore, the oil and gas industry, regulators, and academia have a deep interest in understanding the different mechanisms that lead to reservoir containment loss as well as the strategies to avoid them. In 2016 the Alberta Energy Regulator (AER) released Directive 86 to regulate SAGD projects in shallow reservoirs. Directive 86 explicitly requires geomechanical modelling and reservoir monitoring for new project applications. Geomechanical simulation is commonly carried out using simplified models that assume homogeneity of the reservoir and geomechanical properties. Nevertheless, it is well known from formation evaluation that the reservoir and surrounding rocks are heterogeneous due to the complex sedimentary environment. If heterogeneity is not considered, simulation predictions for caprock integrity become unreliable.

On the other hand, monitoring is currently performed in most SAGD projects in Alberta. The monitoring programs do not follow a consistent workflow making them costly and poorly efficient. The main objective of this research was to bring knowledge from geotechnical engineering monitoring into the SAGD reservoir surveillance world. A widely used logic-based methodology from geotechnical engineering is adapted for SAGD projects. The procedure aims to strategically design monitoring programs that can assist in improving the understanding of the subsurface behavior and maximizing the value of field observations. Even though the primary purpose of this research is to focus on reservoir containment monitoring, the methodology is helpful to answer different relevant questions for SAGD projects.

Studying the subsurface's response to thermal recovery is a complex task, given that many physics are involved during the process. Various tools and data should be considered as rock characterization, coupled geomechanics-flow numerical simulation, and field observations. All information should be appropriately gathered following engineering criteria to maximize the value and reveal the subsurface behavior for specific conditions. Understanding the behavior helps operate the project at safe conditions optimizing the economics of the project.

The proposed methodology is based on engineering criteria and aims to select the most appropriate instruments and location and plan data acquisition, interpretation, presentation, and implementation. Hence, the methodology follows several steps systematically: defining project conditions, predicting mechanisms that control behavior, defining questions that need to be answered, and predicting the magnitude of change. The methodology is then applied to a commercial project showing the usefulness of the methodology for monitoring planning.

Initially, a 3D heterogeneous geomechanical model is built for a specific pad to capture as many different properties in the reservoir and caprock as possible. The model is adopted as the "true model" of the SAGD pad. Next, thermal-hydro-mechanical (THM) numerical simulation is performed to evaluate the response of parameters that are commonly measured in monitoring programs at different operating conditions. The results from the simulations help identify the influence of heterogeneity and operating conditions on the observation data. Simulation results also help identify the most appropriate monitoring to be used and where instruments should be installed to ensure reservoir containment during SAGD operation. Next, A simple approach to assess risk in thermal operations is developed to identify areas of concern for thermal projects. The results show the significance of considering geological heterogeneity when planning reservoir surveillance in SAGD projects.

Finally, the methodology proposed in this research is applied to a real case study. The case study corresponds to the most renowned caprock failure in thermal recovery, Joslyn Creek. The analyzed data corresponded to post-failure operations when an ambitious monitoring plan was deployed to ensure operations' safety. The results demonstrated the importance of using the methodology to plan a cost-effective monitoring program. Also, different technologies used in SAGD to measure surface heave are compared to identify the discrepancies between them that aid in selecting the most appropriate technology for future projects.

8.2 Contributions

- Adapted systematic approach to planning monitoring programs in SAGD project. A widely used approach used in geotechnical engineering has been adapted to SAGD projects, including all the challenges and particularities of SAGD projects. The approach is a logic-based workflow that aims to design monitoring program based on initial predictions and preliminary knowledge of the project. This research includes a chapter where the systematic approach is explained step by step, helping practitioners to design cost-effective monitoring programs.
- Established the importance of considering subsurface heterogeneity for caprock integrity studies. This research demonstrated the impact of heterogeneities in the reservoir and caprock on the simulation and monitoring results. Cake layer homogeneous models are commonly used for caprock integrity studies, given the complexity of the problem. However, this research compared homogeneous and heterogeneous models showing significant discrepancies in results. It is crucial to consider heterogeneities to obtain realistic predictions.
- Developed a methodology for computing risk indices based on a static geological model. This methodology can help identify safety concern areas of SAGD projects based on geological information alone. The risk index can be a helpful tool to identify potential risk areas and plan monitoring programs without running geomechanical simulations when resources or time are a concern.
- Demonstrated role of preliminary simulation and analysis in selecting monitoring instrument locations. Monitoring programs can be significantly improved by performing geomechanical results.

8.3 Conclusions

This research demonstrated through geological modelling, reservoir simulation, and a case study that reservoir monitoring planning for SAGD can be significantly improved by applying a commonly used methodology in geotechnical engineering projects. The general conclusion is presented below, followed by specific conclusions from each chapter.

8.3.1 General conclusion:

Reservoir geomechanics is a specialty that is continuously evolving and constantly enriched by other engineering specialties such as geotechnical engineering. A cost-effective monitoring design is crucial in thermal recovery given the challenging conditions as depth and hostile environment requiring costly instrumentation and installation procedures. The knowledge and experience gained in geotechnical applications over decades to manage risks can be applied successfully to different subsurface problems such as thermal recovery in oil sands. This research demonstrated that a logic-based methodology to design and plan monitoring programs for reservoir containment could maximize the value of data collected. Furthermore, the systematic approach to plan monitoring can also be used for reservoir surveillance to optimize bitumen production.

Given the cost of monitoring in SAGD, one of the main challenges when designing a monitoring program is the selection of the location where the measurements are optimal. The concept of the value of information is critical to ensure data quality while reducing the number of instruments and, subsequently, monitoring costs. Uncertainty of the subsurface and the process as well the dynamic nature of SAGD, further complicate the optimal selection of location for instrumentation. This research proposes a methodology to select the optimal location of the instruments to maximize the value of information through numerical simulation and geological models. The methodology is applied in a case study showing its efficiency to improve monitoring designs, reducing the number of devices required significantly without affecting the quality of results.

8.3.2 Chapter 3 Conclusions:

- The knowledge gained in geotechnical engineering to make decisions based on observational data can be expanded to different problems related to subsurface and geomaterials. In particular, the systematic approach to plan monitoring design proposed by Dunnicliff was successfully adapted to thermal recovery of bitumen in the oil sands.

- Sufficient understanding of the subsurface and its expected response to steam injection are required to obtain an effective monitoring design. Furthermore, the questions that need to be answered should be stated to plan the monitoring as well as how the monitoring measurements aim to answer such questions.
- SAGD monitoring has specific challenges that must be considered during planning, such as the cost of observation wells (drilling and completions), a hostile environment for instrumentation (high-pressure, high-temperature, and corrosion), and subsurface heterogeneity. Those challenges make the selection of the location of the instrument a demanding step that requires predictions of geomechanical response and engineering judgment to ensure enough observation data is collected, optimizing the monitoring budget.

8.3.3 Chapter 4 conclusions

- Facies distribution analysis based on gamma-ray logs shows considerable vertical heterogeneity in the reservoir and caprock formations. Moreover, the geological conditions of the subsurface can change significantly within the analyzed pad area. Therefore, Geomechanical/flow models should include geological heterogeneity of the formations to capture the actual response of the subsurface to steam injection requiring the use of fine grid elements to represent the variations.
- Facies distribution analysis of McMurray formation suggests that a significant amount of clay is encountered in the layer. High clay content is commonly found in inclined heterolithic stratification (IHS) sand that corresponds to sedimentary environments where sand and clay are deposited cyclically. Furthermore, continuous mud layers in the reservoir act as barriers that stop the steam chamber growth and the applied load to the caprock.

- The proportions of clay and sand contents within the Wabiskaw formation are very similar, making it difficult to characterize the formation and assign flow and geomechanical properties to grid-blocks. Moreover, Wabiskaw formation is crucial in caprock analysis and monitoring design in the Athabasca area since the clayey lower section is the first vertical seal that prevents upwards flow. The sandy section is commonly used to monitor vertical pressure migration.

- Pore pressure measurements of the area suggest that the reservoir is not hydraulically connected to the upper layers exhibiting a sudden change at the top of the reservoir. The measurements show that pore pressure at the reservoir is significantly lower than the pressure at the caprock layers. Minifrac test results also suggest that the minimum stress gradient obtained at the caprock differs from one obtained at the reservoir, suggesting that the formations are at different faulting regimes (normal faulting for reservoir and thrust faulting for caprock).

8.3.4 **Chapter 5 conclusions**

- Understanding steam chamber geometry is crucial to assess the safety of SAGD operations since it governs the applied load to the caprock. Numerical simulations have demonstrated that the most effective parameter that should be monitored to identify chamber growth is the temperature within the reservoir. On the other hand, pressure monitoring within the reservoir might not help understand steam chamber geometry since significant leak-off can be expected, and pressure can go faster and further than steam in the porous media. However, pressure measurements within the reservoir can be used to identify reservoir heterogeneity and lateral containment

- Simulation results, as well as field observations, suggest that heat transfer to the upper layer can be expected by conduction. Measuring and understanding temperature changes within the caprock are crucial to ensure reservoir containment as they can result in deformation and, subsequently, stress state alteration. Moreover, increasing temperature in impermeable zones can result in thermal-induced pore pressure if the heating rate is higher than the excess pore pressure dissipation rate. Thermal-induced pore pressure was observed in simulations results for Wabiskaw clay and the lower section of Clearwater, altering the effective stress significantly. Furthermore, according to simulation results, thermal-induced pore pressure can be observed in Wabiskaw Sand if the formation is not lateral continuous. Wabiskaw Sand is widely used in the Athabasca area to monitor fluid migration upwards. Therefore, understanding thermal-induced pore pressure in the zone can be critical for monitoring planning and avoiding false alarms during operations.

- Geological heterogeneity plays a key role in subsurface response to steam injection. This chapter compares results obtained from homogeneous and heterogeneous models, exhibiting significant discrepancies in the monitored variables as pressure, temperature, and displacement. The results demonstrate the relevance of geological interpretation to assess SAGD risk and to plan an effective monitoring program.
- SAGD is a dynamic process where pressure, temperature, and displacement within the reservoir constantly change for the project's life span, hindering the selection of the optimal in-situ location of instruments. Simulation results show that for late times the most appropriate location to measure displacement within the reservoir is at the flank of the pad where displacement continuously increases as steam chambers grow and coalesce around the well-pairs. However, measuring displacement within well-pairs can be helpful to identify abnormal behaviour at early times of the projects.
- Vertical displacement at the base of the caprock is highly correlated to the temperature distribution within the reservoir, according to simulation results. Moreover, vertical displacement at the base of the caprock is directly proportional to the caprock's safety factor, highlighting the need to understand steam chamber growth and temperature distribution within the reservoir to evaluate reservoir containment.
- Surface heave measurements have become the most popular geomechanical surveillance technique in thermal recovery. This chapter analyzes the predicted heave from numerical simulations to evaluate its effectiveness in monitoring

subsurface events. Simulations results show that surface displacement is greatly attenuated by the stiffness of the upper layer minimizing or masking the actual response of the reservoir and caprock to steam injection. Surface heave measurements are indirect measurements and require geomechanical information of the overburden that is not often available. Furthermore, simulations of a case where the injection pressure is close to the minimum stress (near-failure conditions) show that surface heave is limited to capture subsurface events as shear and tensile failure at the base of the caprock. However, surface heave observation can be helpful to estimate steam chamber growth when the observations are complemented with different sources of data as production/injection and temperature distribution within the reservoir.

8.3.5 Chapter 6 conclusion:

- SAGD is a Multiphysics process that requires complex and costly analysis to predict the geomechanical response of the subsurface to be used in monitoring planning. Chapter 6 introduces a methodology based on heterogeneous geological models to calculate a risk index that aims to identify safety concern areas in the analyzed model quickly. Such areas can be considered critical areas helping select the locations of the instruments according to the systematic approach. The risk index includes geological heterogeneity from the reservoir that governs the steam chamber (applied load to caprock) and from the caprock that governs caprock strength. Even though the risk index calculation could be a useful tool to make fast decisions, it is important to bear in mind that the risk index is calculated from static/initial conditions and does not include any wellbore information as well placement and operating strategy.

8.3.6 Chapter 7 conclusions:

- Observations obtained from surface heave monitoring are affected by external factors as overburden stiffness, reservoir depth, vibrations, and weather. The monitoring program deployed in Joslyn SAGD project after the 2006's blowout included InSAR corner reflectors with different pillar depths to analyze the effect of temperature on measurements. Initially, 65 corner reflectors were installed at a depth of 5 meters, and one year later, 30 more corner reflectors were installed at a depth of 7 meters. The analysis of monitoring data shows that measurements obtained from short pillars are highly affected by weather fluctuations during the spring season when the soil thaws. In contrast, the data collected by deeper corner reflectors were not significantly influenced by temperature changes. These results confirm that external factors can affect ground displacement measurements, and the information obtained is limited to interpreting the subsurface if the instruments are not properly installed.

- This chapter analyzed the observed surface heave recorded by different monitoring techniques after 20 months of SAGD operations. The results from the different instruments show a similar spatial behavior where the maximum vertical deformation was measured at the middle of Well-pair 4. Nevertheless, the magnitude of the displacements measured by the different instruments varies considerably. The difference can be explained by the external factors that affect measurements. Moreover, the maximum heave recorded during the analyzed period was obtained at the same latitude that the crater generated by 2006's blowout and just a few hundred meters west of it, suggesting that the area is a potential concern for SAGD operations. Further investigation with numerical simulations shows that reservoir quality in the area is higher than the rest of the pad, increasing the Risk Index, confirming that it can be used to select instrument locations.
- Measurements obtained from d-GPS are highly affected by recoding frequency (every two weeks), resulting in significant reading fluctuations exhibiting low precision measurements. In contrast, tiltmeter measurements are reported daily, and curves obtained for displacement versus time are smoother. Observations from different techniques follow similar trends, but the absolute value discrepancies from one method to another can be as high as 300%. The differences are attributed to sensor sensitivity and external factors like weather, drilling in the area, and traffic. Furthermore, all the different techniques evaluated in the case study can capture some changes in the closest well-pair operating

strategy, suggesting that ground displacement is highly correlated to steam injection.

- The value of information obtained by tiltmeters was evaluated by randomly reducing the total number of instruments in the project. The number was reduced from 135 to 4 covering the same area. The analyses suggest that the tiltmeters could be randomly reduced from 135 tiltmeters to 17 without observing material changes in the displacement map. Thus, the tiltmeter number reduction of 77.5% could be translated into significant savings in the monitoring program cost without affecting the quality of observation data.
- Moreover, when simulation results are used to select the locations of the instruments, the number of tiltmeters can be reduced to just four tiltmeters in the area without affecting the final interpretation. This analysis shows the relevance of designing monitoring programs based on geomechanical analysis and predictions. Finally, the analysis suggests that four tiltmeters obtain the highest value of information from the whole array, and if strategically located, they can obtain the same information.
- Similar results were obtained when using the risk index in the analyzed data. However, the Risk Index should be accompanied by wells placement and injection strategy to ensure selected locations are optimal for the conditions of the project.

8.4 Recommendations for future work

- SAGD is a complex process where many physics coincide as flow in porous media, fluid-phase changes, chemical interaction between fluids and rock, and geomechanical deformation. Furthermore, the properties are heterogeneous and anisotropic. Including all the physics and heterogeneities for 3D modeling requires significant computation effort and time. Given the uncertainty to model SAGD, it is recommended to use data analytics and machine learning techniques to generate predictive models based on field observations for rapid decision making. Such models should include all available monitoring data as production/injection, temperature, pressure, and deformation distribution. Ideally, the model should also include basic physics and geology information for verification to ensure the reliability and the quality of decisions in the long term

- It is recommended to evaluate in more detail instrumentation for displacement with higher precision. Also, direct measurements at the base of the caprock using devices such as magnetic bullets or in-situ extensometers. The devices should be placed at different strategical locations within the pads to identify deformation geometry.

- The results from numerical simulation show that elements within the caprock follow different stress paths. Laboratory testing following such stress paths is recommended to understand caprock behavior. Strength properties should be obtained following the changes in pressure and stress identified in numerical modelling. More investigation is also recommended to investigate thermal-induced pore pressure in the caprock and its implication on operations safety. Thermal-induced pore pressure investigation will help improve understanding of mechanisms that control behavior to apply the systematic approach of this research.

- Larger scale models are recommended to identify the impact of different pads operations and vintages on the subsurface's geomechanical response and the consequent results in monitoring. Larger scale models will also help to understand the influence of adjacent areas on the deformation and subsequently identify potential risks of new pads.

- It is recommended to develop a model that can simulate tensile fracture initiation and propagation. Understanding fracture mechanics help design monitoring and alarms to control fracture initiation and growth that could breach the caprock.

- Recent advances in data analytics and Machine Learning could integrate geomechanics and safety with conventional reservoir management and optimization. "Smartfield" is a term that has been used to denominate surveillance strategies that are automated where surveillance observations are directly connected to operating devices to control variables as flow rate and pressure, including geomechanical measurements as surface displacement and pore pressure in the upper layers will add significant value to the loop to make real-time decisions to optimize the recovery process without affecting the project safety. Moreover, this research demonstrated that geomechanics response is tightly correlated with reservoir performance; geomechanical measurements should also be included in the algorithms used to optimize the efficiency of the recovery process.

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