Root Cause and Regulatory Response Report

Canadian Natural Resources Ltd. Primrose Bitumen Emulsion Releases, 2013

March 2016

Alberta Energy Regulator
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Executive Summary

This report documents the Alberta Energy Regulator's (AER's) investigation into the root cause of five bitumen emulsion flow-to-surface (FTS) events that occurred at Canadian Natural Resources Limited's (CNRL's) Primrose and Wolf Lake high-pressure cyclic steam stimulation (HPCSS) operations, located inside the Cold Lake Air Weapons Range, approximately 20 kilometres (km) northwest of Cold Lake. The first FTS event was discovered in January 2009, and the four subsequent events were discovered in May and June 2013. The report also describes the AER's regulatory response to the events. The report does not address the environmental impacts or the cleanup and remediation of the FTS sites.

The first four events occurred in the eastern part of CNRL's Primrose operations; the fifth event occurred in the southern part. The AER responded to the events by issuing two letters in June and July 2013 that suspended steaming operations at Primrose East and suspended some and modified other operations at Primrose South and North, including more stringent monitoring requirements.

The geology at Primrose is very complex, and geological weaknesses due to salt dissolution may limit the ability of strata to prevent fluid migrating to the surface. CNRL considers the Colorado Group as the main caprock for its HPCSS operations, but the AER considers the Clearwater capping shale to be the caprock, although the AER acknowledges the presence of other barriers to vertical flow above the Clearwater capping shale such as the Colorado Group.

CNRL undertook an extensive field investigation program related to the most recent FTS events that included drilling 54 wells to delineate the bitumen emulsion in the Colorado Group; re-entering 21 open-hole abandoned wells to investigate the role of wellbores in the FTS pathways; collecting approximately 38 kilometres (km) of conventional logs, 22 km of formation image logs, and 7 km of core; acquiring geomechanical data for the Colorado Group; and performing seismic analyses around all FTS sites.

On October 21, 2013, Alberta Environment and Sustainable Resource Development (now Alberta Environment and Parks) issued an enforcement order that required CNRL to have the findings of its investigation reviewed by an independent third-party expert panel.

There were differences in interpretations among CNRL, the panel, and the AER regarding the possible pathways for the FTS events, so the exact pathways were not definitively determined. CNRL's view was that wellbore pathways were the most likely and efficient way for bitumen emulsion to travel vertically, but CNRL acknowledged that natural fractures and faults in the shales and vertical hydraulically induced fractures could not be dismissed. The panel's view was that CNRL's approach had insufficiently addressed the impact of geological variability, such as natural discontinuities and variations in the in situ stresses, on the mechanisms controlling the flow paths. The AER's view is that all the FTS events were caused by excessive steam volumes combined with an open conduit, such as wellbores, natural fractures or faults, and hydraulically induced fractures. While CNRL stated that a wellbore contributed to each of the FTS events, the AER believes that a wellbore likely contributed to the flow path at only one of the FTS events.

Since the exact pathways for the FTS events were not definitively determined, sufficient controls need to be applied to account for all the different possible pathways. To reduce the likelihood of future bitumen emulsion FTS events, regulatory controls will be imposed at CNRL's Primrose operations. These controls include limiting steam injection volumes, reducing bottomhole injection pressures, enhancing the monitoring system, and remediating any fluid-flow pathways associated with wellbores.

1 Background

1.1 Bitumen Emulsion Release Incidents and Responses

On May 20, 2013, two flow-to-surface (FTS) releases of bitumen emulsion were discovered at the Primrose and Wolf Lake (PAW) high-pressure cyclic steam stimulation (HPCSS) project operated by Canadian Natural Resources Limited (CNRL). The project is located inside the Cold Lake Air Weapons Range, approximately 20 kilometres (km) northwest of Cold Lake, as shown on figure 1.

The FTS releases occurred at Legal Subdivision 10, Section 1, Township 67, Range 3, West of the 4th Meridian (10-01-067-03W4M [10-01]) and 10-02-067-03W4M (10-02) within an area of the PAW project commonly referred to as Primrose East Area 1. The release at 10-01 was close to a previous FTS release of bitumen emulsion that occurred in January 2009 at pad 74. On June 8, 2013, a third FTS release of bitumen emulsion was discovered at 02-22-067-03W4M (2-22) in an area commonly referred to as Primrose East Area 2. On June 14, 2013, in response to the three FTS releases, the Alberta Energy Regulator (AER) ordered the suspension of all steaming operations within Primrose East.

On June 24, 2013, CNRL reported a fourth FTS release of bitumen emulsion within a surface water body at 09-21-067-04W4M (9-21). The 9-21 site is located between phases 21 and 22 and is within an area commonly referred to as Primrose South.

Figure 2 shows the locations of the four 2013 FTS releases and the location of the 2009 FTS release.

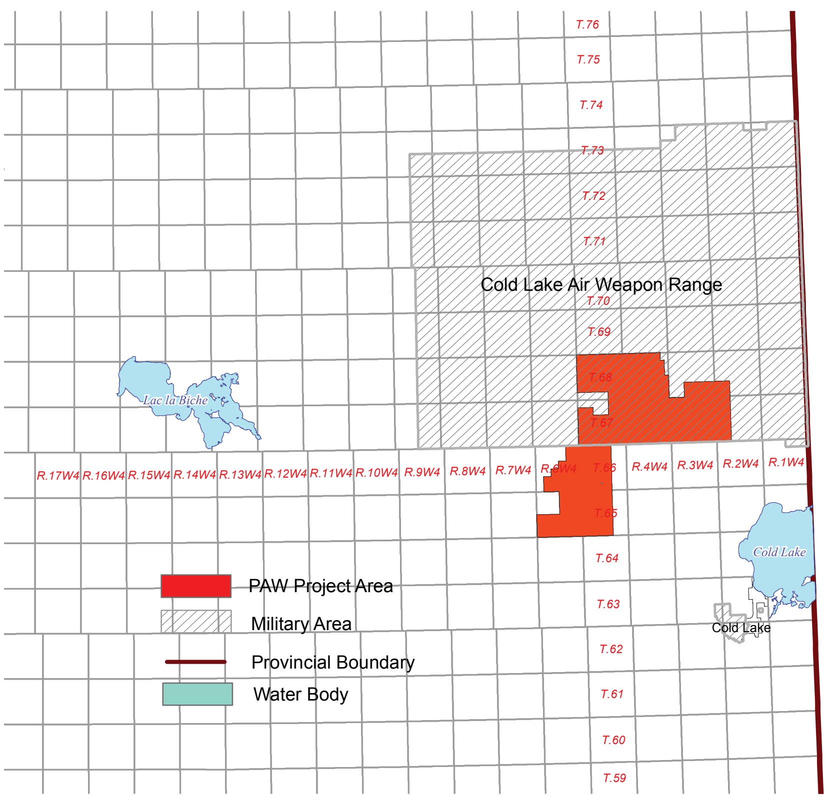

Figure 1. Location of Primrose and Wolf Lake Project.

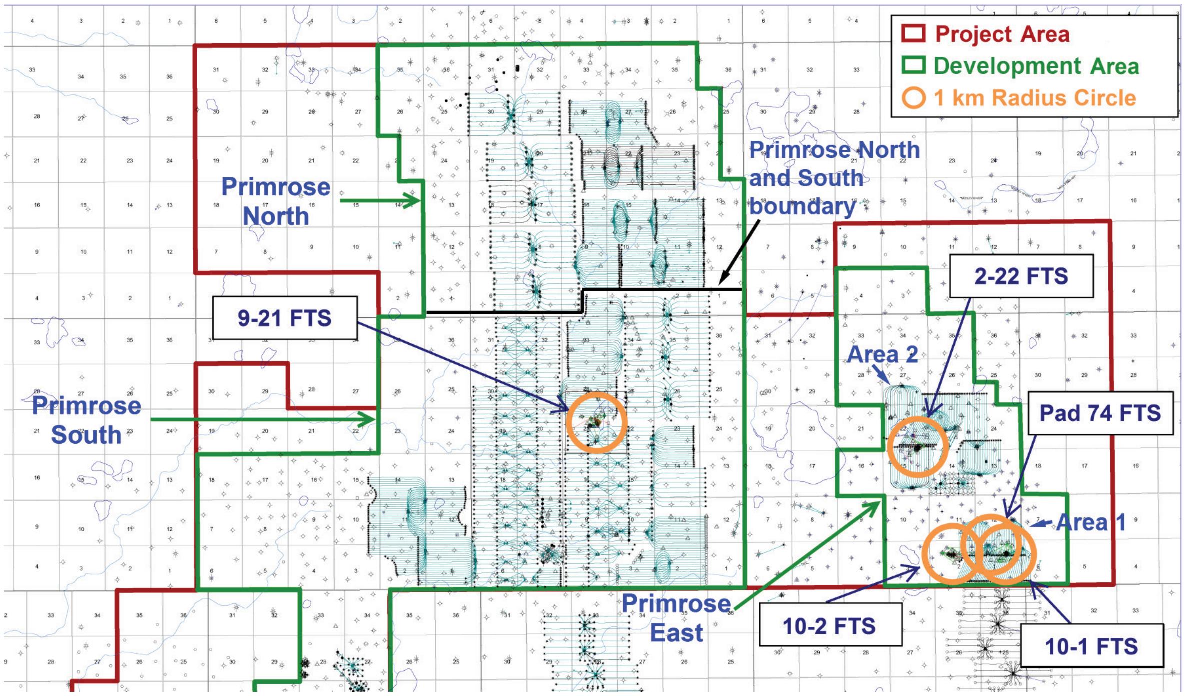

Figure 2. Location of the five FTS releases of bitumen emulsion (modified from CNRL 2015, figure 2.1-1).

In response to the surface releases, CNRL stopped HPCSS operations in all of the affected areas and flowed back all wells to reduce the reservoir pressure. CNRL completed an aerial sweep of Primrose North and South after the discovery of the releases, and no additional releases were identified.

In response to the four surface releases, by a letter dated July 17, 2013, the AER ordered CNRL to

- submit detailed containment, clean up, and remediation plans for all four sites;
- submit a plan to confirm that all surface releases of bitumen emulsion within the PAW project area had been identified;
- suspend steaming operations within 1000 m of the 9-21 site;
- modify steam injection operations throughout the Primrose North and South areas, including
  - reducing overall cycle volumes,
  - capping volume above fill-up (VAF) (not increasing the VAF from cycle to cycle), and
  - tapering steam volumes at the edges of steam waves;
- implement more stringent operational monitoring protocols;
- conduct a risk assessment of and develop a mitigation plan for existing wellbores in the vicinity of pads prior to steaming; and
- develop and implement an incident investigation plan to determine the root cause of the four surface releases.

This report focuses on the root cause and regulatory response to the FTS events and does not address the environmental impacts or the cleanup and remediation of the FTS sites.

1.2 Regional Geology

The stratigraphic column for Primrose is shown in figure 3.

1.2.1 Surficial Geology

During the Quaternary and Neogene periods, preglacial fluvial streams and glacial melt waters eroded deep valleys into the Lea Park Formation and the Colorado Group. These valleys are either preglacial fluvial or glaciofluvial erosional features that are generally filled with a basal sand and gravel overlain by glacial till with intercalated sands and gravels. The sands and gravels formed freshwater aquifers. No incisions are present at the FTS sites; however, they are present within Primrose and are located between Primrose South and Primrose East.

1.2.2 Bedrock Geology

At Primrose, the bedrock consists (from youngest to oldest) of Cretaceous (Lea Park, Colorado Group, and Mannville Group) and Devonian strata.

1.2.2.1 Lea Park and Colorado Group

When combined, the Lea Park Formation and the underlying Colorado Group result in a shale interval varying in thickness from 140 to 300 m. The Colorado Group comprises relatively impermeable shale, mudstone, siltstone, and fine sandstone of the Niobrara, Second White Specks, Belle Fourche, Fish Scales, Westgate, Viking, and Joli Fou formations. At Primrose, the Lea Park and the upper part of the Colorado Group have undergone both regional (preglacial) and local (subglacial) channelization, possibly resulting in creation of faults and fractures that may act as natural conduits to fluid flow. A polygonal fault system is present within the lower part of the Colorado Group with fault displacements on the order of 1 to 5 m. The polygonal faults are interpreted to be closed to fluid flow under static conditions. The upper portion of the Niobrara Formation and overlying strata normally have in situ stress states that favour vertical hydraulic fracturing; whereas the lower portion of the Niobrara and underlying Colorado formations have in situ stress states that usually favour horizontal hydraulic fracturing.

1.2.3 Cretaceous Mannville Group

The Mannville Group consists of the Grand Rapids, Clearwater, Wabiskaw, and McMurray formations. The Grand Rapids Formation underlies the Colorado Group. It consists of two units, the Upper and Lower Grand Rapids. The Grand Rapids Formation has an in situ stress state that favours vertical hydraulic fracturing. The Upper Grand Rapids consists up to 55 m of interbedded sands and shales. The uppermost Colony Member is often gas saturated. The Lower Grand Rapids at Primrose and Wolf Lake comprises up

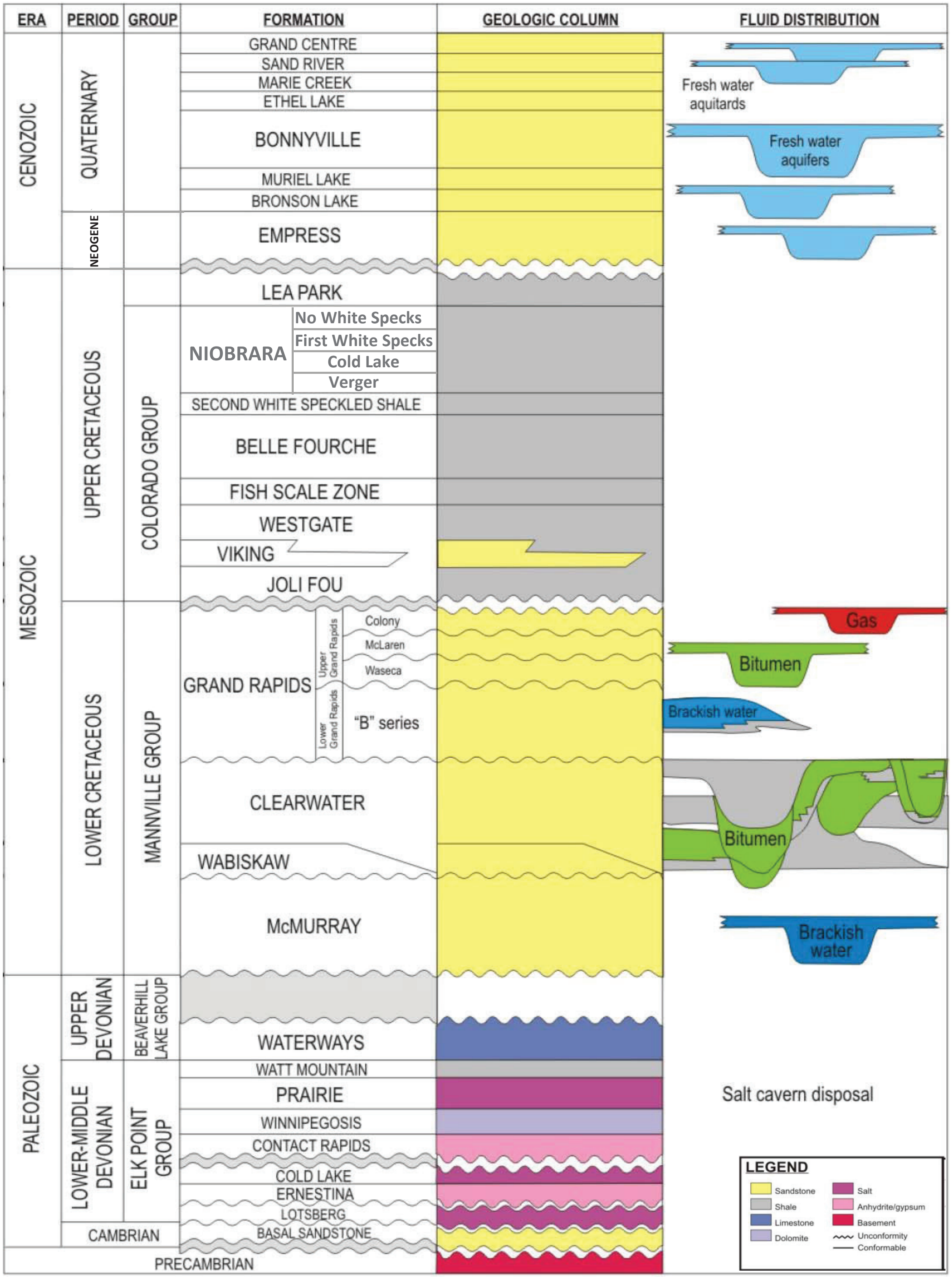

Figure 3. Stratigraphy of Primrose (modified from CNRL 2011, figure 2.2-2).

to 60 m of distinct sandy parasequences (referred to as “B2” to “B12” units) typically separated by shales. The basal Lower Grand Rapids water sand, referred to as the Rex (B12) and General Petroleum (B10) members, is a targeted pressure monitoring zone for releases from the underlying HPCSS reservoir. The basal Lower Grand Rapids water sand ranges in thickness from 10 m in the northwest area of Primrose South to 40 m at Primrose East. Pump testing indicates that the Lower Grand Rapids water sand behaves like an areally extensive aquifer with effective permeabilities ranging from 100 to 1200 millidarcies (mD).

At Primrose, the Clearwater Formation consists of regional shales and thin sands that have been incised by younger valley sand systems and is capped by Clearwater capping shale. The regional transgressive shale is 2 to 6 m thick and is referred to in this report as the Clearwater capping shale. The Clearwater capping shale has an in situ stress state that favours horizontal hydraulic fracturing. Gas pools can be present under the capping shale. The Clearwater reservoir has an in situ stress state that favours vertical hydraulic fracturing.

The Wabiskaw Member and the McMurray Formation underlie the reservoir and overlie the sub-Cretaceous unconformity.

The Devonian consists of calcareous shales and limestones of the Beaverhill Lake Group, underlain by carbonates, clastics, and evaporites of the Elk Point Group. The evaporites of interest are within the Prairie Evaporite Formation and include water soluble halite (salt) and less soluble anhydrite. The Devonian surface is highly variable and locally channelized due to approximately 250 million years of erosion and the dissolution of the underlying salt. The thickness of the Prairie Evaporite Formation at Primrose South is 175 m and gradually thins to about 95 m at Primrose East.

1.2.4 Primrose Area Structural Controls

Cretaceous strata at Primrose South dip to the southwest, which follows the regional geological trend throughout Alberta. The Cretaceous strata at Primrose East were deposited when salt dissolution was actively occurring and resulted in subsidence and dip reversal to the southeast. The salt dissolution process controlled sediment thickness and the degree of structural heterogeneity, which changed the regional stress states and created faults and fractures. Two main factors controlled the degree of these changes: (1) the timing of the dissolution in relation to the deposition of Cretaceous sediments, and (2) the volume of salt dissolved. Pre- and syn-depositional salt dissolution influenced the sediment thickness while post-depositional salt dissolution created void space leading to subsidence, structural instability, and the creation of faults and fractures in the overlying strata.

As mentioned above, part of Primrose East is located in an area with up to 80 m of salt dissolution and localized collapse structures and geological weaknesses. In contrast, Primrose South has the full thickness of the Prairie Evaporite Formation intact. Figure 4 shows the structural complexity of the Devonian surface.

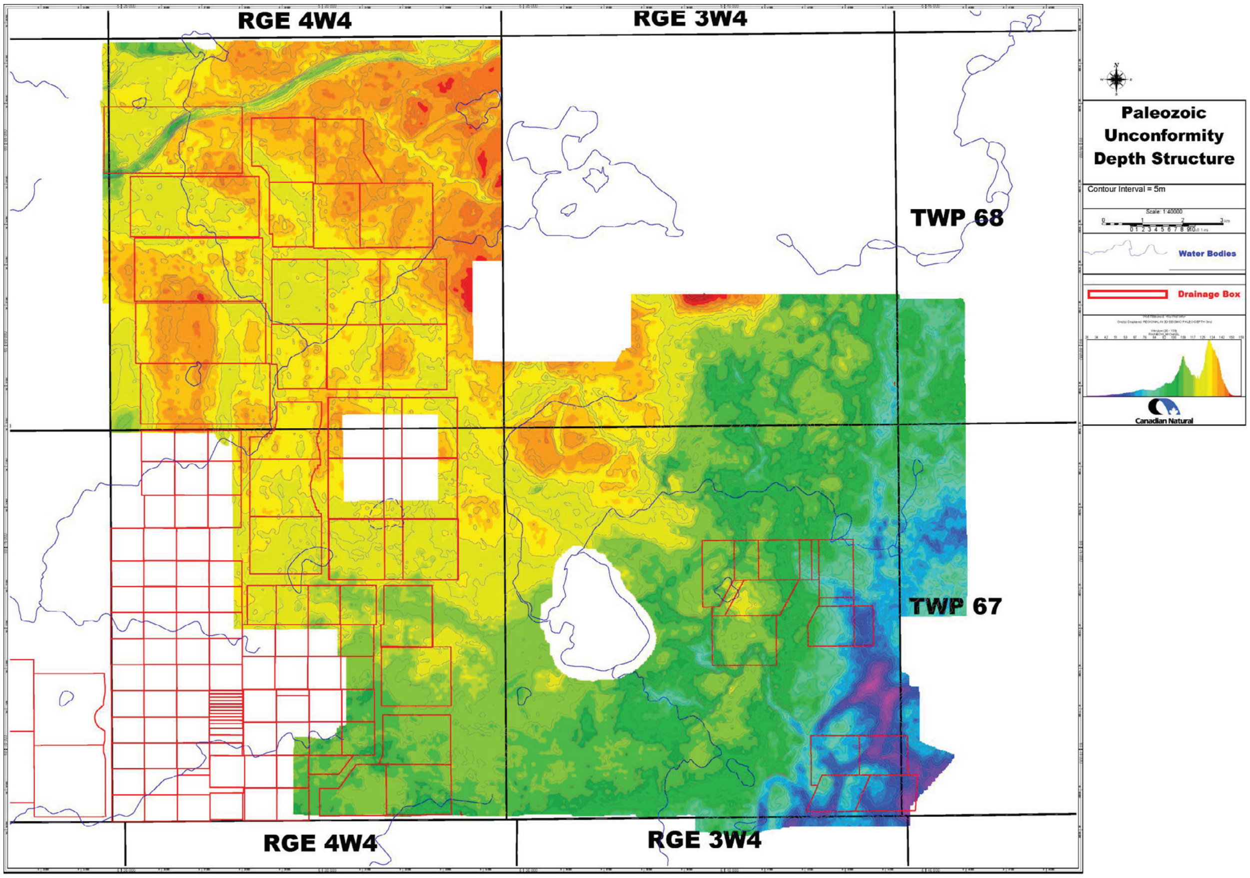

Figure 4. Paleozoic top structure map from seismic (modified from CNRL 2015, figure A.10-13).

1.2.5 Caprock

CNRL considers the Colorado Group as the main caprock for CSS operations in the Mannville reservoirs, whereas the AER considers the Clearwater capping shale to be the caprock for CSS operations in the Clearwater reservoir at Primrose. In addition to the Clearwater capping shale, the AER acknowledges the presence of other barriers to vertical fluid flow above the Clearwater bitumen reservoir, including the Lea Park Formation and Colorado Group at Primrose.

The historical loading of the Lea Park Formation and Colorado Group shales involved burial, mountain building, glacial loading and unloading, and local salt dissolution (Primrose East). All these processes developed fractures and faults within these strata. Even though these shales have low matrix permeability, fractures and faults of variable intensity and orientation are present in these zones that may limit their ability to prevent vertical fluid migration to surface.

The Clearwater capping shale is laterally continuous; however, it is thin, and fractures are present. Primrose East is located within the salt dissolution area where post-depositional disturbance occurred, resulting in local geological weaknesses within the Clearwater capping shale.

CNRL has mapped approximately 2900 conductive fractures, resistive fractures (filled with bitumen), and seismic-scale faults throughout the Mannville and Colorado strata from seismic data, cores, and image logs. The data interpretation indicates that the overall fracture intensity is very low. The majority of the mapped fractures are within the Lea Park and First White Specks formations with an average spacing of 2.2 m and between 10 and 30 m in the formations below. Measured fracture intensity is greater at Primrose South in the Lea Park, Belle Fourche, Westgate, Viking, and Grand Rapids formations. In contrast, the average spacing is larger at Primrose East in the Joli Fou Formation. Further analysis performed by CNRL confirmed that faults and fractures are uniformly distributed in most of the formations. In the Joli Fou Formation, the majority of the fractures are present in the lower half.

1.3 Operations Prior to FTS Releases of Bitumen Emulsion

Development in the PAW project area began in 1980. CNRL acquired the project in 2000 and later expanded and converted the wells from below-fracture-pressure CSS to above-fracture-pressure CSS (also called high-pressure CSS, or HPCSS). In 2007 CNRL received AER approval to expand the project area to the east. This development, known as Primrose East Area 1, included a new steam generation facility and four new phases comprising 80 HPCSS wells at the time of the initial release at pad 74. Subsequently, six additional phases comprising 120 wells were added in 2011 as Primrose East Area 2.

HPCSS operations at Primrose use horizontal wells to inject steam into the Clearwater reservoir at high pressures. The interwell spacing at Primrose East is 60 to 80 m, while the interwell spacing at Primrose South is 60 to 188 m. Steam injection rates of a well are typically 1800 to 2200 cubic metres (m^3) per day.

Each HPCSS cycle consists of an injection phase and a production phase. For the injection phase, CNRL uses either a pressurized steam wave strategy (by which wells are steamed in a sequential pattern to limit interwell communication) or a block steam strategy (by which all wells within a phase are steamed at once). Each HPCSS well goes through a number of cycles throughout its productive life.

1.3.1 FTS Sites at Pad 74, 10-01, and 10-02

In 2006 CNRL began piloting larger per-cycle steam injection volumes on reduced well spacing (60 to 80 m versus 188 m) in an attempt to increase recovery and reduce the time required to deplete the reservoir. The expansion in 2007, known as Primrose East Area 1, included phases 74, 75, 77, and 78, comprising 80 wells with 800 to 900 m horizontal well lengths.

CNRL began cycle 1 steam injection at phase 77 on August 29, 2008, and at phase 78 on September 25, 2008. By October 1, 2008, a seven-row steam wave had been established, and cycle 1 production began at phase 77 in October 2008 and at phase 78 in November 2008. At the time of the pad 74 bitumen emulsion release, 26 wells had completed their first steam injection cycle. Primrose East Area 1 well operation status on January 2, 2009, is shown in figure 5.

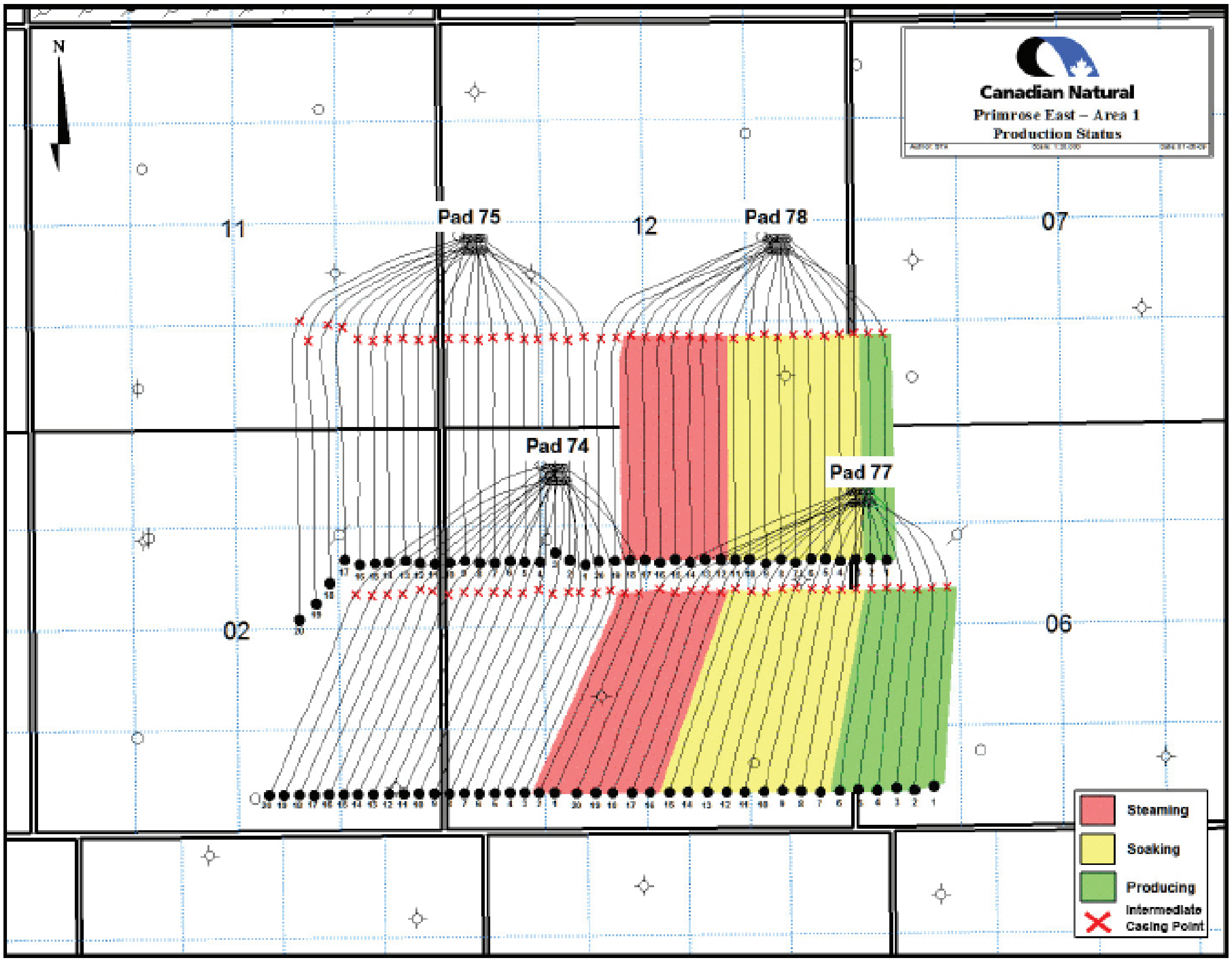

Figure 5. Primrose East Area 1 well operation status on January 2, 2009 (from AER 2013, figure 4).

At the time of the pad 74 incident, each phase at Primrose East had operational passive seismic and thermal fibre monitoring wells installed to detect horizontal movement of fluid in the shales of the Colorado Group. Each HPCSS well was also monitored using differential pressure alarms to detect well failures. While the passive seismic and thermal fibre monitoring systems were functioning correctly up to the time of the FTS release, the monitoring data was not interpreted as a loss of reservoir containment.

Following the initial FTS event at pad 74, CNRL undertook a three-phased diagnostic steam injection program with observation wells in the Lower Grand Rapids basal water sand to assess reservoir fluid containment. Area 1 had no additional steaming after the diagnostic steaming ended in August 2012.

On May 20, 2013, when the 10-1 and 10-2 FTS events were discovered, the Primrose East monitoring system had been enhanced through the addition of pressure monitoring observation wells in the Grand Rapids Formation. At the time of the 10-1 and 10-2 incidents, the monitoring system was functioning correctly. The last steaming at phases 74 to 78 occurred in August 2012. Figure 6 shows the locations of FTS sites at pad 74, 10-01, and 10-02.

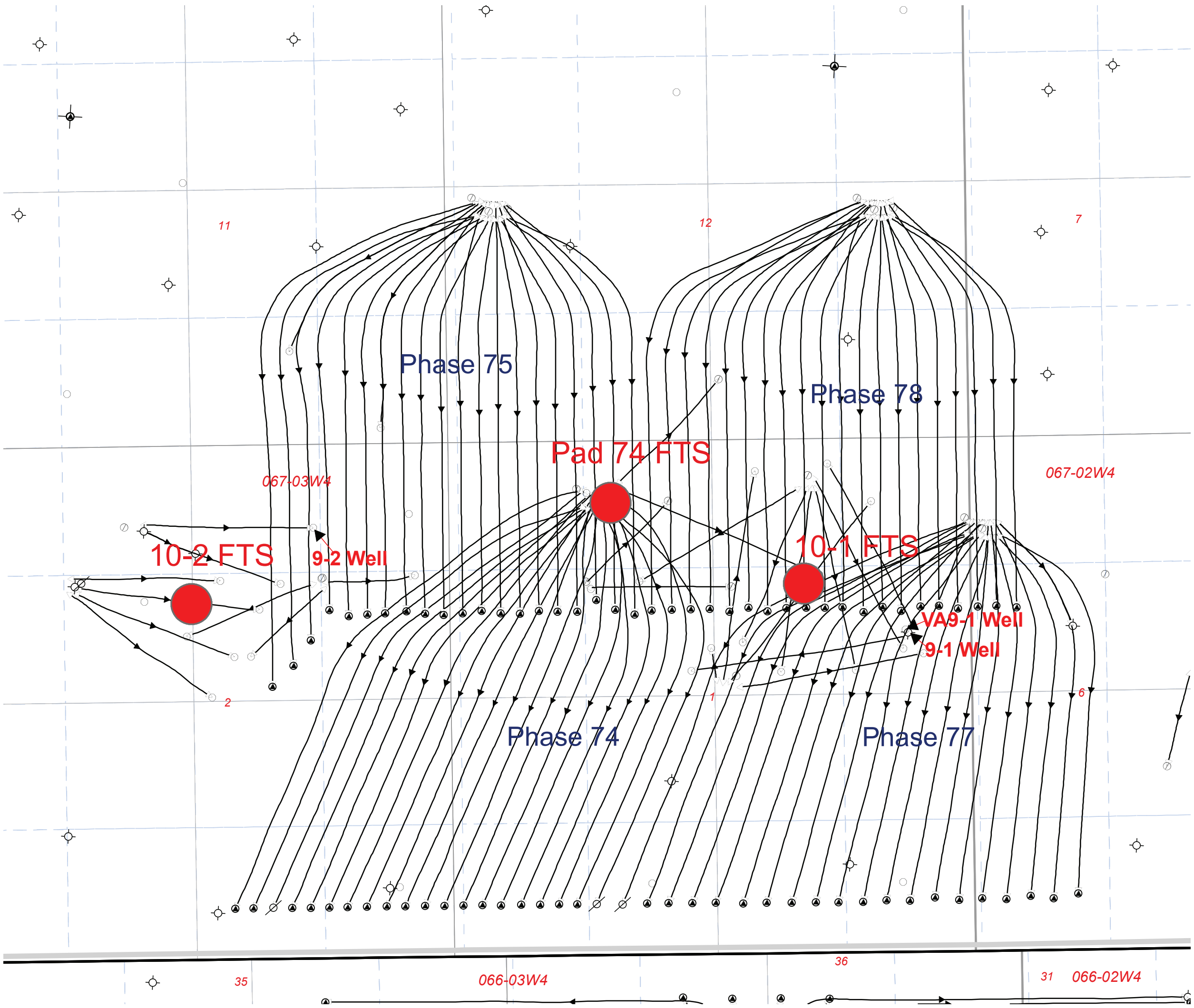

Figure 6. Surface bitumen emulsion releases at pad 74, 10-01, and 10-02 FTS sites.

1.3.2 FTS Site 2-22

Following the January 2009 FTS release at pad 74, additional wells were drilled in Primrose East Area 2. Figure 7 shows that the 2-22 site is in the area of these new wells.

The development of Primrose East Area 2 includes 120 horizontal HPCSS wells on six phases: 90 to 95. HPCSS wells in these phases were drilled with lateral lengths ranging between 500 and 1450 m and well spacing ranging between 60 and 86.5 m.

Due to the presence of a gas cap within the Clearwater Formation in phase 94, one well at phase 94 (11A94) was perforated to enable the direct injection of steam into the gas cap in order to pressure it up before injecting steam into the underlying bitumen reservoir. This was done to minimize fluid and pressure losses to the gas cap during HPCSS operations.

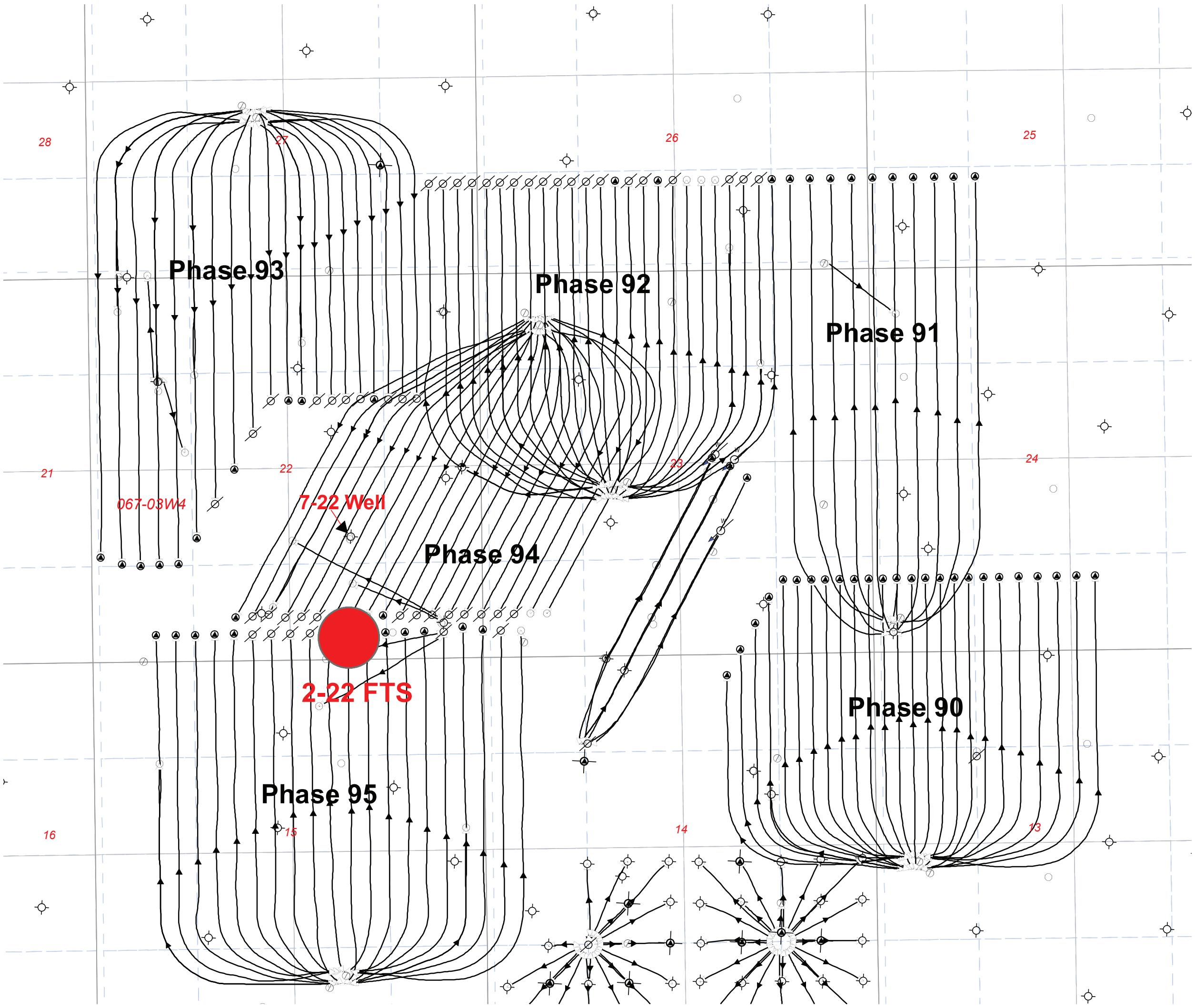

Figure 7. Surface bitumen emulsion release at 2-22 FTS site.

Cycle 1 steam injection at phase 95 began in August 2012, while production began in September 2012. Cycle 1 steam injection at phase 94 and cycle 2 steam injection at phase 95 both began in January 2013. Production at phase 94 began in April 2013.

The bitumen emulsion release at the 2-22 site was discovered between phases 94 and 95 on June 8, 2013. At the time of the bitumen emulsion release, phase 95 was on cycle 2 production, while phase 94 was on cycle 1 production. At the time of the 2-22 incident, the monitoring system was functioning correctly.

1.3.3 FTS Site 9-21

The surface release of bitumen emulsion into a surface water body at 09-21-067-04W4M is the first known release outside the Primrose East area. Figure 8 shows the location of the 9-21 FTS site and the surface water body. The site is located between phases 21 and 22 at Primrose South.

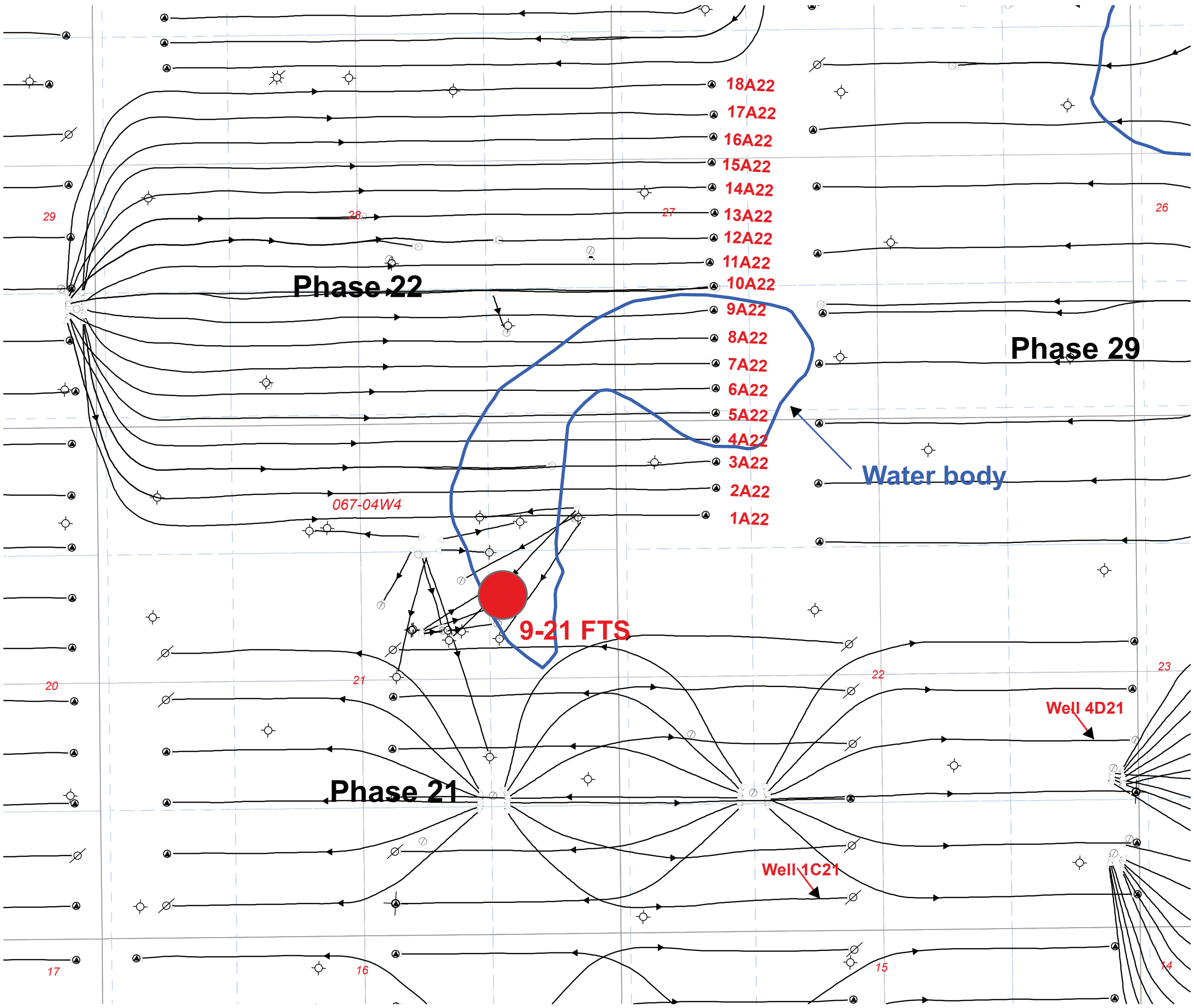

Figure 8. Surface bitumen emulsion release at 9-21 FTS site.

Phase 21 consists of 24 horizontal wells with lateral lengths of 600 m and interwell spacing of 160 m. CNRL executed the first HPCSS cycle at phase 21 on October 4, 2000, and subsequently conducted four additional cycles of HPCSS. No additional steam injection occurred at phase 21 since cycle 5 production began in July 2009.

Phase 22 consists of 18 horizontal HPCSS wells with lateral lengths of 1700 m and interwell spacing of 80 m. Cycle 1 steam injection began on March 18, 2012. CNRL conducted three cycles at phase 22. At the time of the discovery of the 9-21 FTS release, the wells of phase 22 were on production. The southern six wells ceased steam injection and transitioned to production in the previous month to the discovery. Table 1 shows the average steam injection volume per well for each cycle at phase 22. As shown in the table, larger steam injection volumes were used in wells 1A22 to 6A22 during cycle 3 as compared to wells 14A22 to 18A22.

Table 1. Phase 22 steam injection volumes.

Steaming Cycle	Date	Average Steam Injection Volume Per Well (m^3/well)
Cycle 1	March 18 to May 11, 2012	41 000
Cycle 2	June 12 to Aug. 14, 2012	55 000
Cycle 3	Feb. 17 to May 22, 2013	Wells 1A22 to 6A22: 130 000
		Wells 14A22 to 18A22: 86 200

1.4 Investigation

1.4.1 FTS Delineation Wells

The primary purposes of CNRL's delineation drilling program were to (1) define the vertical and lateral components of the bitumen emulsion pathway through the Lea Park Formation and Colorado Group, (2) collect fluid samples to confirm that the source of bitumen emulsion was the Clearwater reservoir, and (3) collect geological and geomechanical data to investigate potential pathways. The drilling program started on August 12, 2013, after the Clearwater reservoir had been depressurized and pressure decreases were observed in the Lower Grand Rapids observation wells. The delineation drilling program ended on June 11, 2014, with 54 Cretaceous wells drilled. Additionally, 21 open-hole abandoned wells were re-entered to investigate the role of wellbores as part of the FTS pathway. CNRL collected approximately 38 km of conventional logs, 22 km of formation image logs, and 7 km of core.

The Cretaceous delineation well types included twinned wells, vertical wells, and deviated wells. Forty-eight of the 54 delineation wells terminated in the Grand Rapids Formation, typically 15 to 20 m above the Clearwater capping shale. Three wells terminated in the McMurray Formation, underlying the Clearwater reservoir. Seven delineation wells terminated at shallower depths, between the Quaternary and the Belle Fourche Formation. Twinned wells were drilled approximately 10 m adjacent to suspect wells within the vicinity of the FTS. Vertical wells were drilled near the surface fracture at each FTS. Most of the delineation wells were slant and directional wells. Slant and directional wells have a higher probability of identifying vertically oriented fractures and faults than vertical wells.

During the drilling program, when bitumen emulsion was seen at surface in the wellbore, a flow check was conducted on the well and a pressure buildup test conducted if there was sustained flow. Where sufficient bitumen emulsion was encountered, samples were collected and analyzed to confirm the source.

A separate Quaternary delineation program was also undertaken, but it was more focused on assessing risks related to the bitumen emulsion remaining within aquifers at each FTS site. Sixty-six Quaternary groundwater monitoring wells were drilled for this purpose.

1.4.1.1 FTS Site 10-01

Fourteen wells (eleven directional and three vertical) were drilled to delineate the subsurface areal extent of the bitumen emulsion release near the 10-01 site. Bitumen emulsion was intersected by three of the delineation wells.

- The 2A74C well intersected bitumen emulsion flowing at a rate of 1 litre per minute (L/min) within the Lea Park Formation, and 0.25 L/min within the Cold Lake Member of the Niobrara Formation.
- The 11A74C well was drilled to investigate a large Colorado Group fault observed on seismic. At this well an interval from the Belle Fourche to the Westgate was cored with 82.8 per cent recovery prior to intersecting flowing bitumen emulsion at a rate of 0.25 L/min within the Westgate Formation.
- One of the vertical wells, the VA9-1 well, twinned the 1AA/09-01-067-03W4 pre-existing wellbore. This well was cored with excellent recovery and image logged for fracture characterization purposes. The VA9-1 well intersected nonflowing bitumen-filled fractures in the Joli Fou Formation.

Figure 9 provides the location of the 10-01 delineation wells and the spatial distribution of bitumen emulsion appearances (black triangles) and elevation above sea level (colour coded boxes) with respect to geological formation tops (colour coded circles), as well as the locations of the 10-01 and pad 74 FTS sites.

1.4.1.2 FTS Site 10-02

Eleven wells (eight directional and three vertical) were drilled to delineate the subsurface release near the 10-02 site. Bitumen emulsion was intersected by six of the delineation wells.

- Well 105/10-02-067-03W4/00 (105/10-02) intersected bitumen emulsion flowing at a rate of 1 L/min within the First White Specks Member of the Niobrara Formation.
- Well 108/10-02-067-03W4/00 (4B11-2) intersected flowing bitumen emulsion at rates of 1 L/min, 1.5 L/min, and no flow but hydrostatic pressure within an interval from the Lea Park Formation to the First White Specks Member, an interval from the First White Specks Member to the Cold Lake Member, and the Second White Specks Formation, respectively.
- Wells 105/10-02, 106/10-02-067-03W4/00 (3A11-2), and 113/10-02-067-03W4/00 (7A9-2) intersected elevated fluid temperatures at the top of the Grand Rapids Formation, which is an indication of fluid migration at the Joli Fou–Grand Rapids interface.
- Well 104/10-02-067-03W4/00 (104/10-02) twinned the pre-existing 108/09-02-067-03W4 wellbore. This well was cored with excellent recovery and image logged for fracture characterization purposes. The 104/10-02 well intersected nonflowing bitumen-filled fractures in the Grand Rapids and Joli Fou formations.

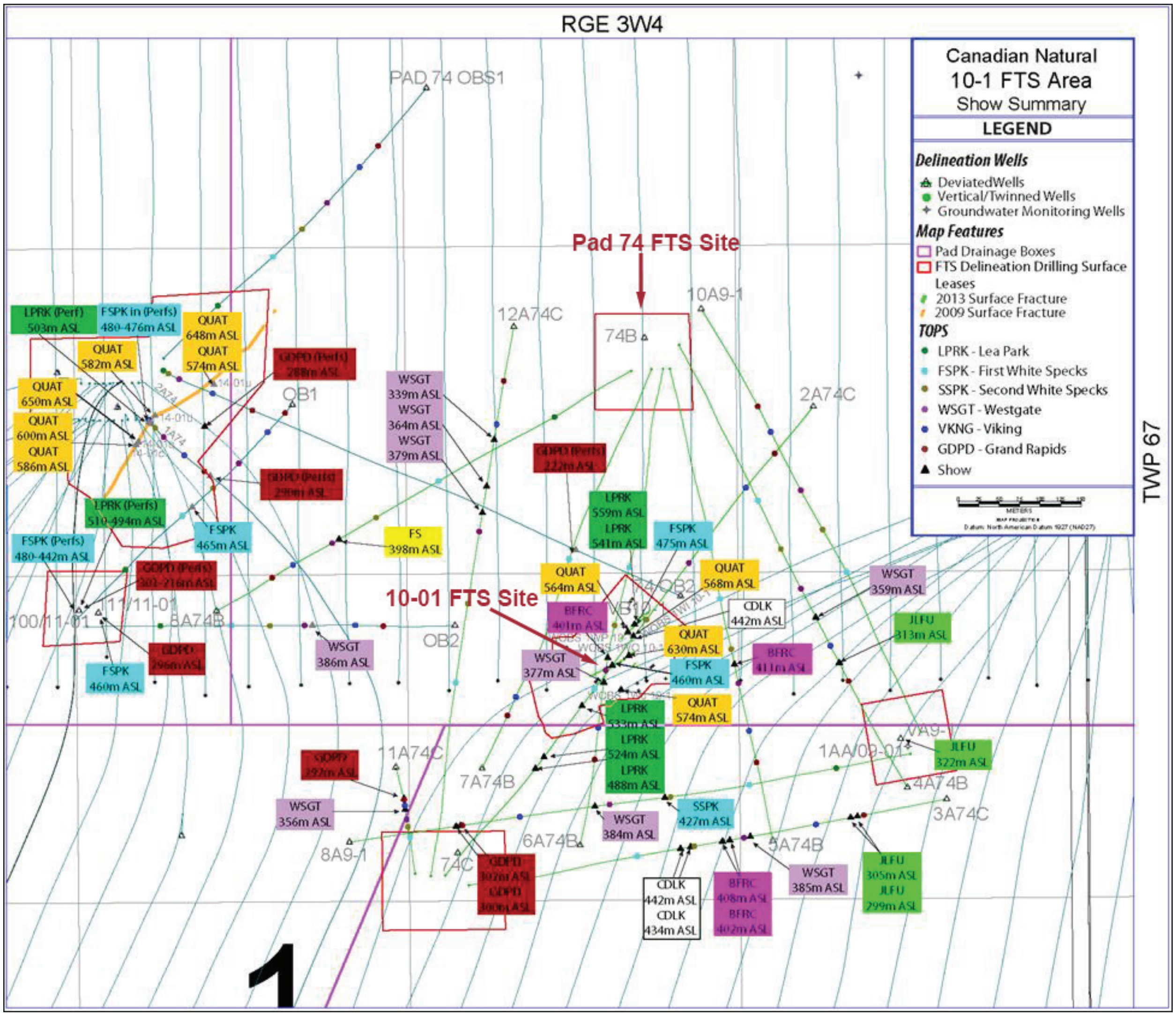

Figure 9. Pad 74 and 10-01 FTS delineation well locations (from CNRL 2015, figure A.11-1).

Figure 10 provides the location of the 10-02 FTS delineation wells and the spatial distribution of bitumen emulsion appearances (black triangles) and elevation above sea level (colour coded boxes) with respect to geological formation tops (colour coded circles), as well as the location of site 10-02.

1.4.1.3 FTS Site 2-22

Eight wells (five directional and three vertical) were drilled to delineate the subsurface areal extent of the bitumen emulsion release near the 2-22 site. Bitumen emulsion was intersected by three of the delineation wells.

- The plug tracking operations at the 100/7-22-067-03W4/00 (7-22) well intersected bitumen emulsion flowing at a rate of 200 and 90 L/min in the Westgate Formation within the open-hole portion of the abandoned wellbore.

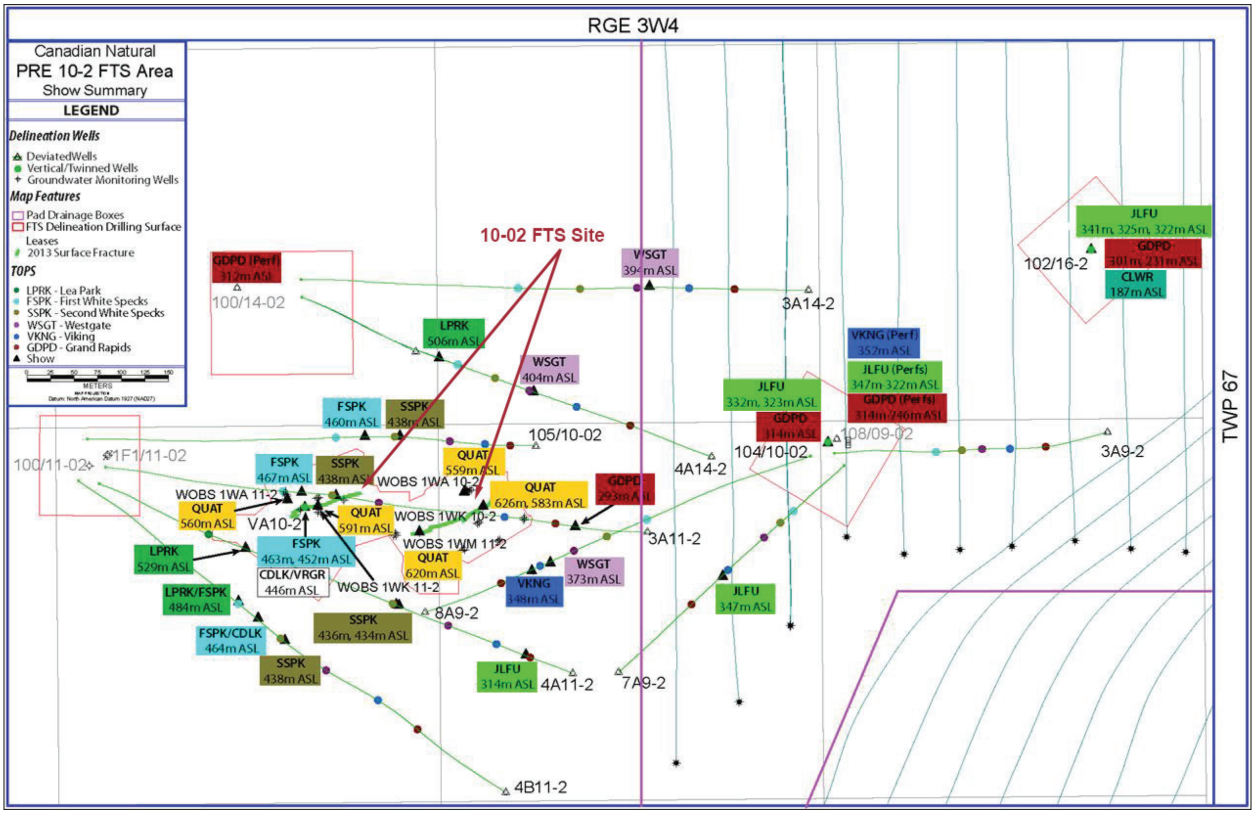

Figure 10. 10-02 FTS delineation well locations (from CNRL 2015, figure A.11-2).

- Well 102/07-22-067-03W4/00 (VA7-22) twinned the 100/07-22-067-03W4 wellbore and intersected flow at a rate of 2 L/min within the Westgate and Grand Rapids formations.
- Well 103/07-22-067-03W4/00 (10B1-22) intersected flowing bitumen emulsion at rates of 1 L/min within the Belle Fourche Formation.

Figure 11 provides the location of the 2-22 FTS delineation wells and the spatial distribution of bitumen emulsion appearances (black triangles) and elevation above sea level (colour coded boxes) with respect to geological formation tops (colour coded circles), as well as the location of site 2-22.

1.4.1.4 FTS Site 9-21

Twenty-one wells (eighteen deviated and three vertical) were drilled to delineate the subsurface areal extent of the bitumen emulsion release near the 9-21 site. Bitumen emulsion was intersected by three of the delineation wells.

- Well 103/10-21-067-04W4/00 (OB2 10-21) intersected bitumen emulsion flowing at a rate of 1 L/min within the Westgate Formation.
- Well 104/09-21-067-04W4/02 (OB10 9-21) intersected flowing bitumen emulsion at a rate of 1.75 L/min within the Quaternary till.

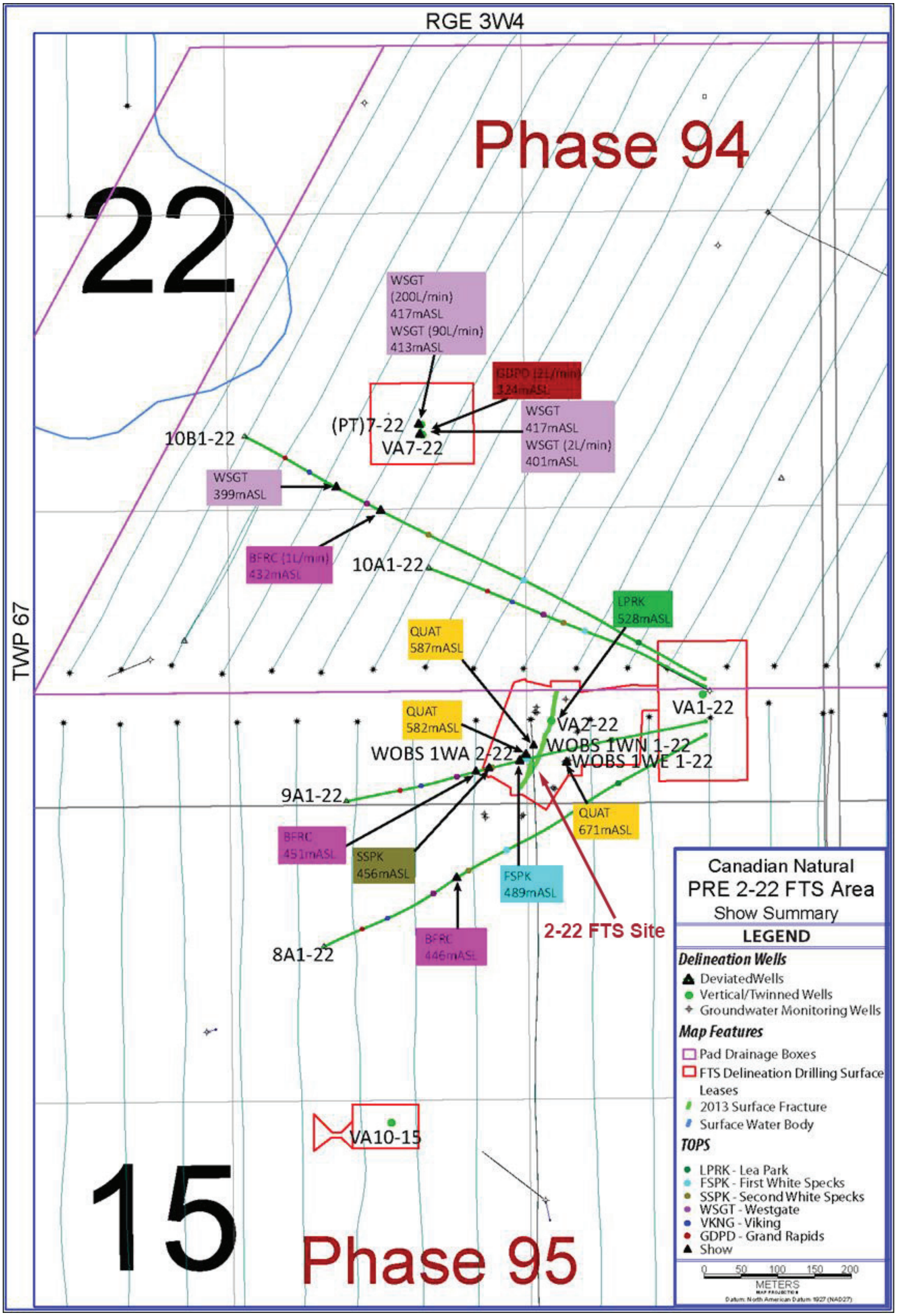

Figure 11. 2-22 FTS delineation well locations (from CNRL 2015, figure A.11-3).

- Well 107/10-21-067-04W4/00 (OB12 10-21) intersected flowing bitumen emulsion at a rate of 2 L/min within the Second White Specks Formation.

Figure 12 provides the location of the 9-21 FTS delineation wells and the spatial distribution of bitumen emulsion appearances (black triangles) and elevation above sea level (colour coded boxes) with respect to geological formation tops (colour coded circles), as well as the location of site 9-21.

1.4.2 Existing Wellbores

In order to investigate the contribution of cased- and open-hole abandoned wells to the FTS events, CNRL evaluated the wellbore integrity of wells close to each of the FTS sites. CNRL conducted a risk assessment on cased wells to evaluate the integrity of the casing and cement. The diagnostic work performed by CNRL included casing caliper logs, cement bond logs, temperature logs, noise logs, pulsed neutron logs, porosity logs, density logs, gamma-ray logs, casing pressure tests, and drilling of twinned wells. Perforations and sampling were conducted for the wells that were suspected to have contributed to the FTS events. CNRL investigated 106 cased wells by conducting various logging and perforations in these wells. CNRL re-entered and remediated the inadequate abandonments in 21 open-hole abandoned wells. CNRL identified the following wells as most likely having contributed to the FTS events:

- well 108/09-02-067-03W4 (9-2), where bitumen emulsion and water were recovered behind the production casing from the Upper Grand Rapids Formation to the Joli Fou Formation;
- well 100/07-22-067-03W4 (7-22; open-hole abandoned), where flowing bitumen emulsion was found within the wellbore interval without a cement plug; and
- well 1AA/9-1-67-3W4 (9-1; open-hole abandoned), where bitumen emulsion was recovered in the Upper Joli Fou Formation from the 111/09-01-067-03W4 (VA9-1 OBS) twinned wellbore drilled in proximity to the 9-1 well.

At least one of the casing failures of the 1C21 and 4D21 wells resulted in the release of Clearwater bitumen emulsion into the Colorado Group. CNRL indicated that the casing failure of the 4D21 well occurred sometime between 2000 and 2003, but the failure was detected during a pressure integrity test on July 5, 2004. The casing failure of the 1C21 well was detected by a pressure integrity test on September 26, 2008.

1.4.3 Seismic Analysis

CNRL interpreted the 3D seismic data by correlating formation tops picked from core and well logs. This geophysical study provided a high-resolution interpretation of geology, which enabled CNRL to delineate faults (with vertical displacement greater than three metres), formation structure, and gas- or steam-saturated intervals throughout the Primrose project area.

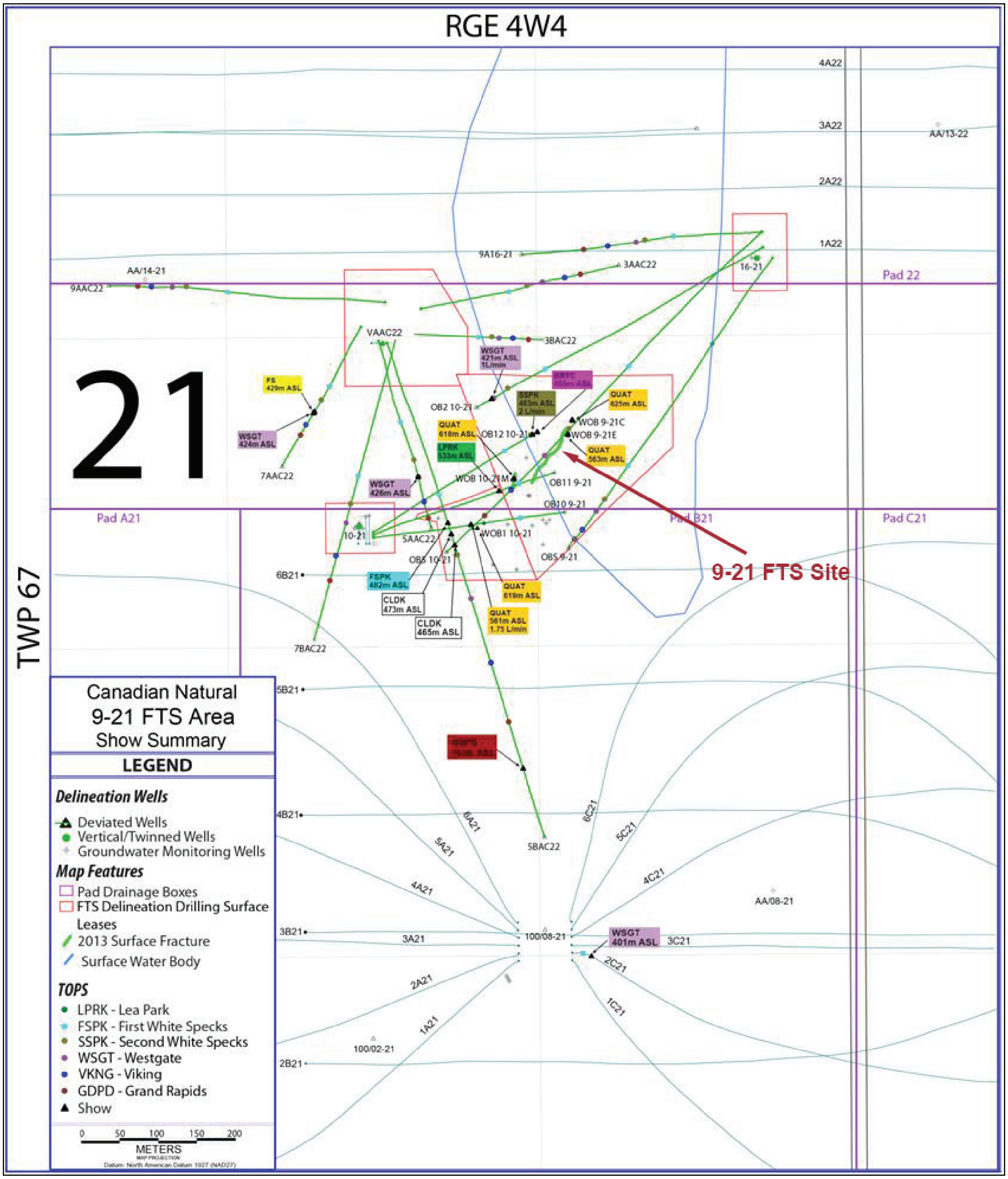

Figure 12. 9-21 FTS delineation well locations (from CNRL 2015, figure A.11-4).

At Primrose, CNRL also obtained post-steaming 3D seismic data, which allowed for time-lapse 3D seismic (i.e., 4D) interpretation of changes in the subsurface due to HPCSS operations. 4D seismic interpretation is traditionally only used to monitor changes in the reservoir (i.e., steam chamber), but after the 2013 FTS releases, CNRL applied similar principles to interpret changes in the Grand Rapids Formation. This 4D seismic interpretation identified several post-steam seismic anomalies (PSSA) in the Grand Rapids Formation. CNRL drilled the 102/16-02-067-03W4 well within a PSSA and cored the Grand Rapids Formation. It was found that the bitumen emulsion in the core originated from the Clearwater reservoir and that gas saturation was present, which suggested solution gas liberation from bitumen. Figure 13 shows a seismic cross-section of the 16-2 PSSA. In the PSSA, the u-shaped pushdown showed in figure 13 is believed to have originated from the presence of natural gas. Figures 14 to 16 show the PSSAs in the vicinity of the FTS sites. For these figures, purple ovals delineate fluid releases to the top of the Rex Member (B12) of the Grand Rapids Formation, green ovals delineate fluid releases to the top of the Sparky Member (B6) of the Grand Rapids Formation, and orange ovals delineate fluid releases to the top of the Colony Member of the Grand Rapids at the Grand Rapids and Joli Fou interface.

1.4.4 Geomechanical Analysis

1.4.4.1 In Situ Stress State

In general, there are three principal in situ stresses: one in the vertical direction and two in the horizontal direction. At Primrose, the maximum horizontal stress is oriented in a southwest direction due to tectonics associated with the forming of the Rocky Mountains. This stress pattern is typical throughout Alberta. Although this general orientation of the stress patterns is consistent with regional trends, local variations associated with local depositional history and structural controls could lead to local variations in stress orientations in relation to the regional trends.

Bulk-density logs from about 200 wells were used by CNRL to calculate an average 21 kilopascals per metre (kPa/m) vertical stress gradient for the overburden formations. Micro fracture injection tests (MFIT) were conducted on 12 wells to determine the minimum horizontal stress gradient, which is the fracture closure gradient for the intervals that were tested in the overburden. The MFIT test results and the vertical stress gradients are summarized in table 2. Figure 17 shows pore pressure and in situ stresses in PAW. Since the measured fracture closure gradients of the Clearwater capping shale, Joli Fou, and Westgate formations are greater than the vertical stress gradient of 21 kPa/m, any induced fractures in these shales would be expected to be horizontal, assuming that no pre-existing vertical planes of weakness are present. Conversely, measured fracture closure gradients in the Grand Rapids shales are less than the vertical stress gradient; therefore, any induced fractures would be vertical. For each of FTS sites, the maximum horizontal stress orientations were determined using passive seismic and microimage logs.

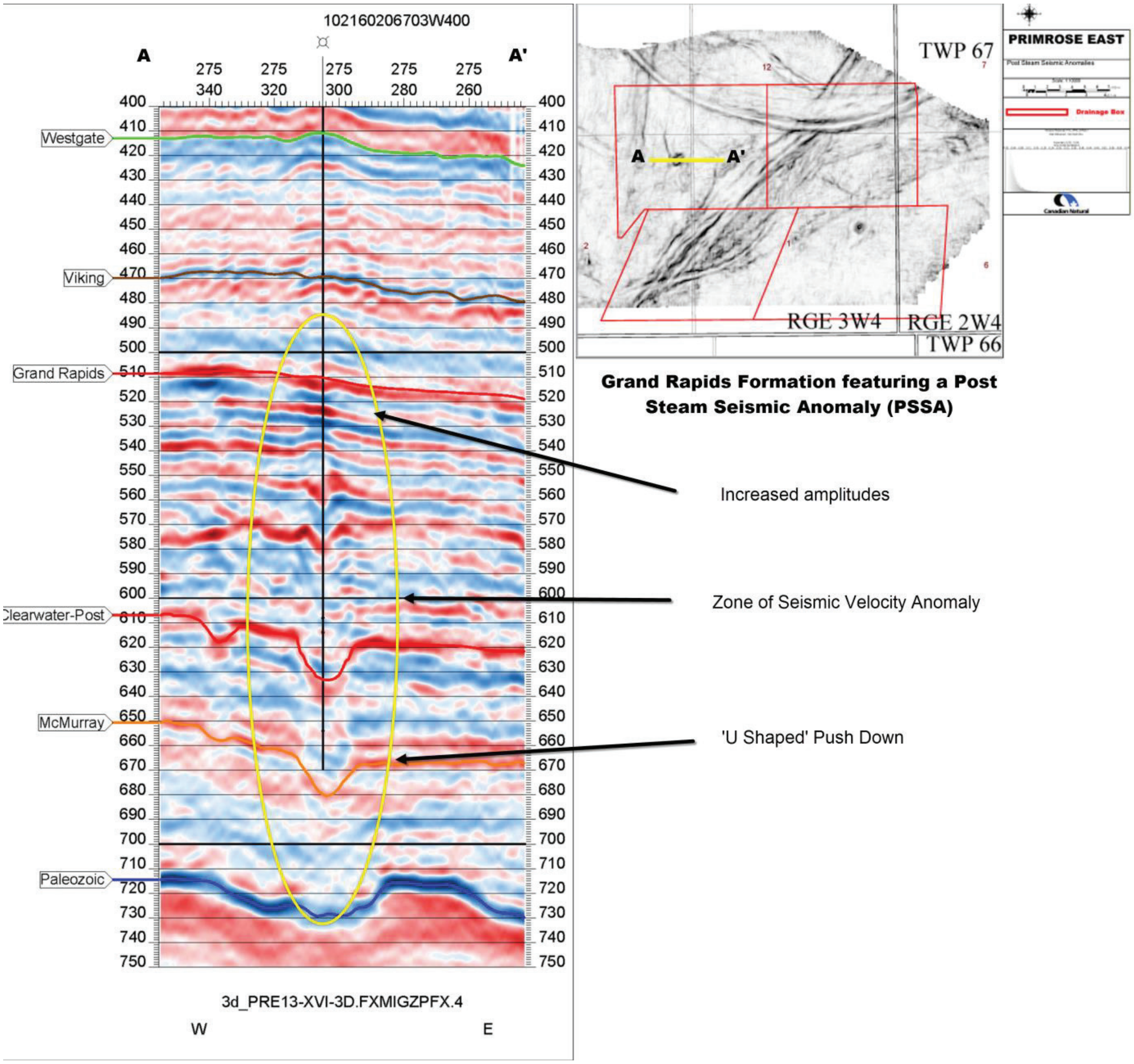

Figure 13. Seismic cross-section of the 16-02-067-03W4 PSSA (from CNRL 2015, figure A.10-43). The figure illustrates a cross-sectional view of a vertical bitumen emulsion column saturated with natural gas migrating upwards from the Clearwater reservoir and through the Grand Rapids Formation as observed on the 4D seismic profile.

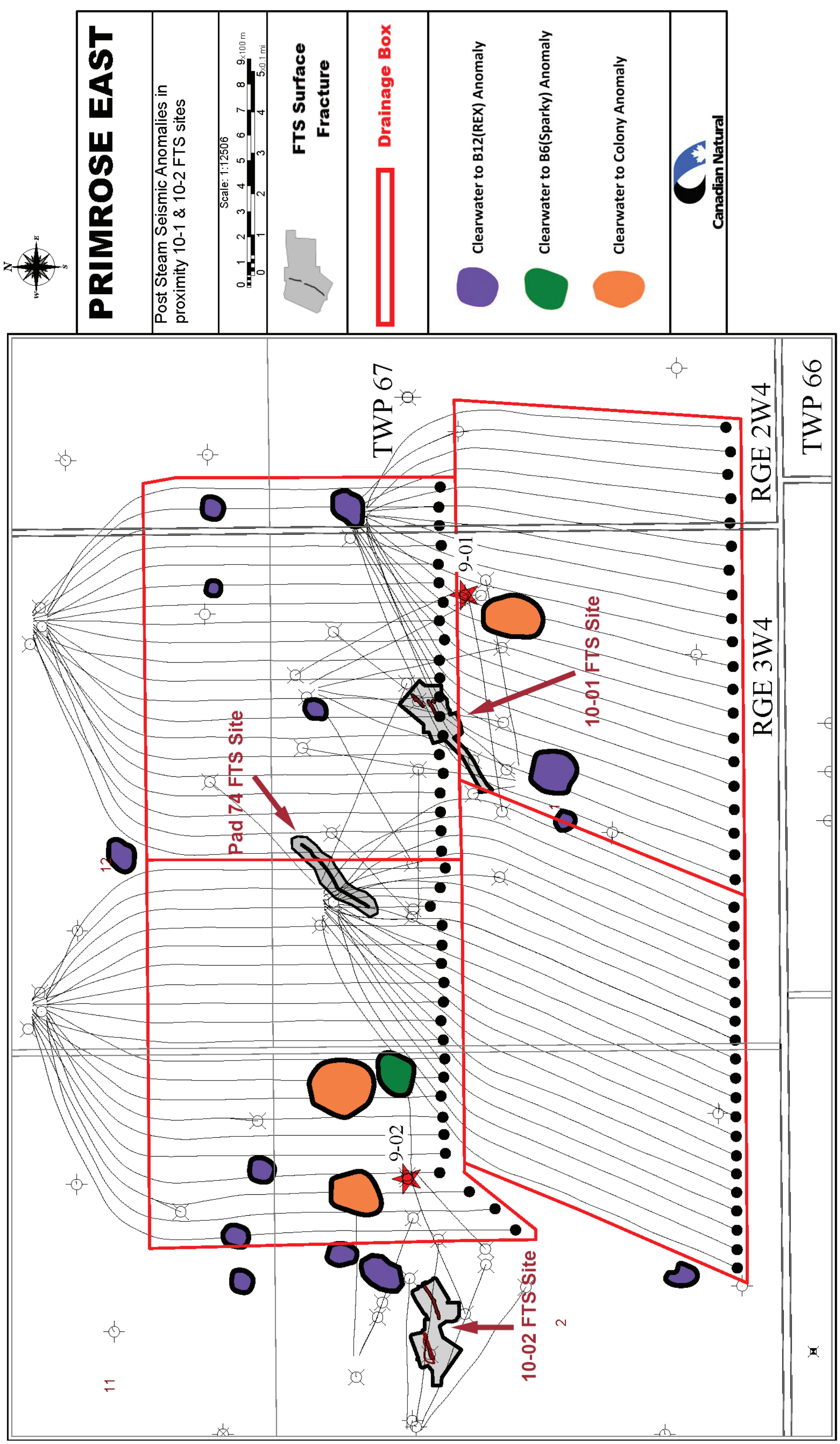

Figure 14. PSSAs near the pad 74, 10-01, and 10-02 FTS sites (modified from CNRL 2015, figure A.10-55).

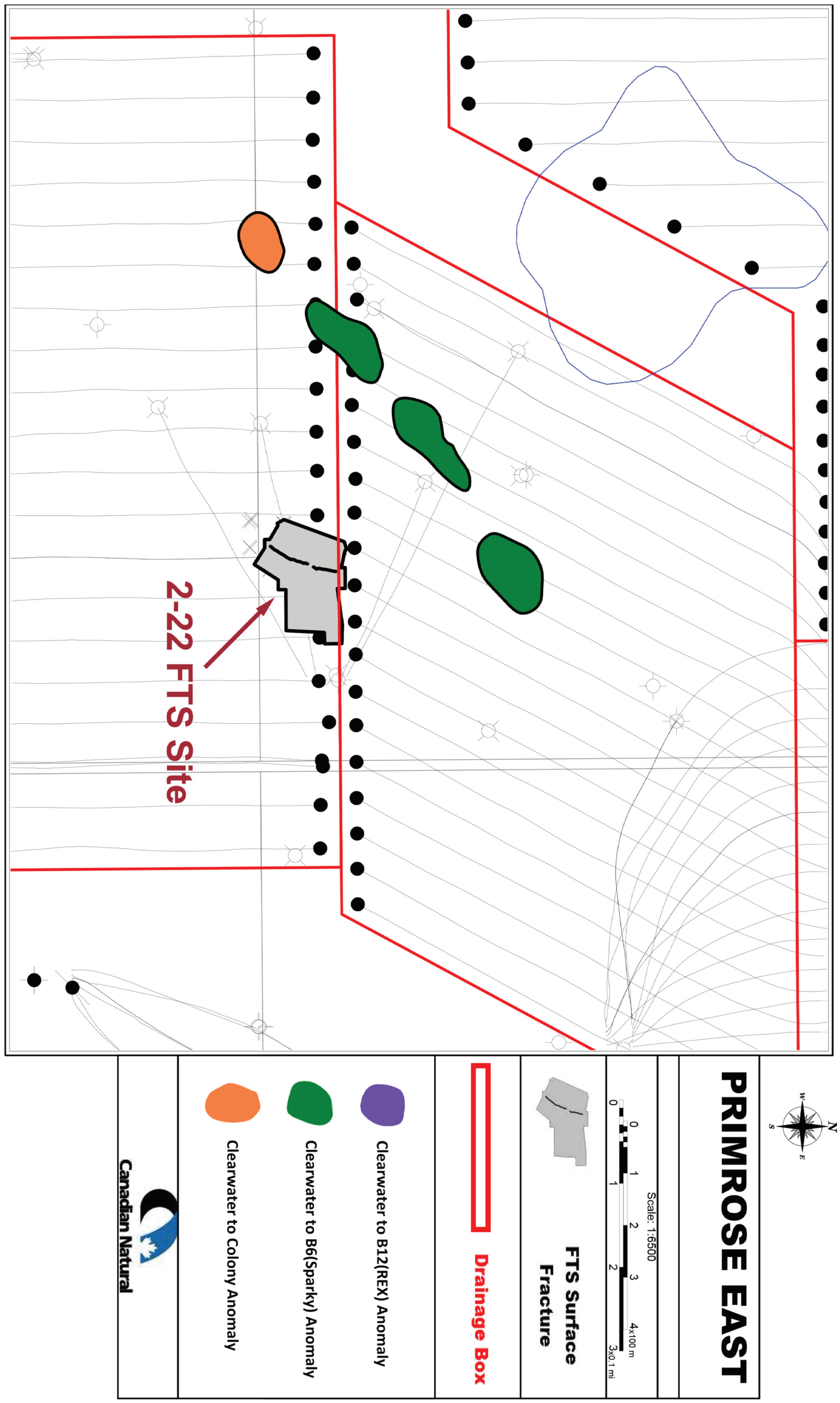

Figure 15. PSSAs near the 2-22 FTS site (modified from CNRL response to supplemental information request).

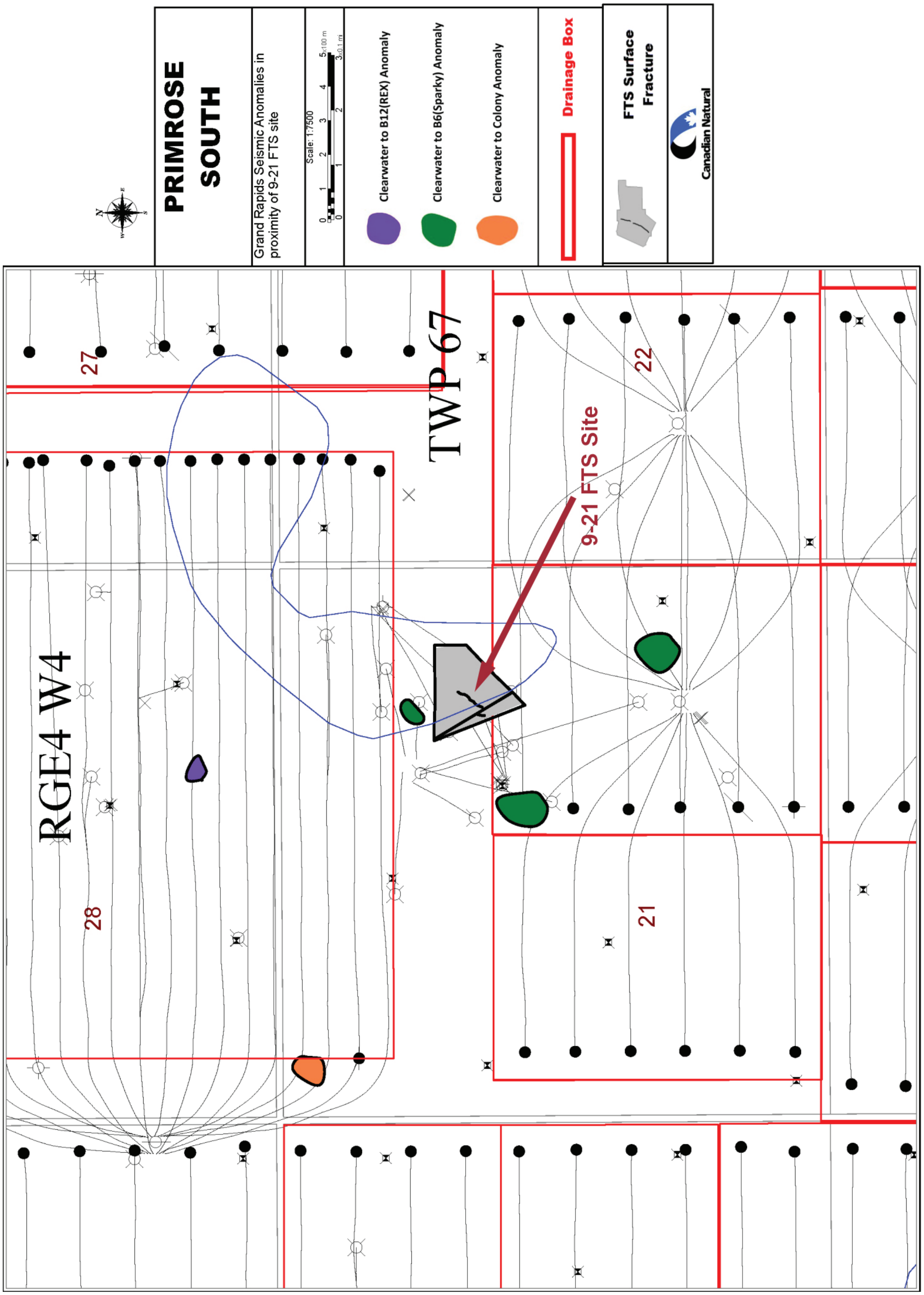

Figure 16. PSSAs near the 9-21 FTS site (from CNRL 2015, figure A.10-54).

Table 2. Summary of MFIT test results and vertical stress gradients within overlying shales of the Clearwater reservoir (modified from CNRL 2015, table 4.4-2).

	Typical Depth Range (mGL)*	Average Minimum Horizontal Stress Gradient (kPa/m)	Typical Vertical Stress Gradient (kPa/m)
Westgate	265–313	29	21.1
Joli Fou	318–352	26	21.1
Grand Rapids Shales	352–463	19	21.0
Clearwater Capping Shale	463–468	27	21.0

* depths are taken from the 108/09-02-67-3W4 well

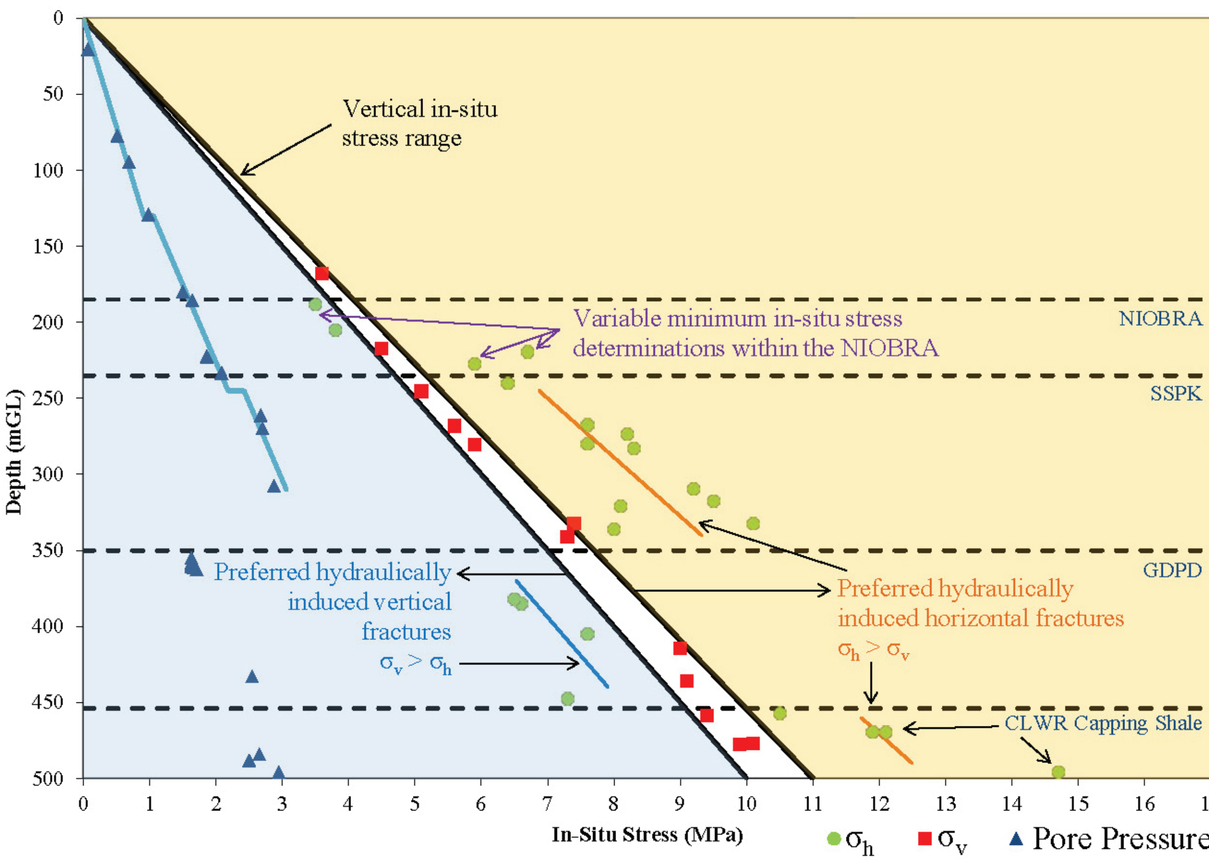

Figure 17. Pore pressure and in situ stresses in PAW (from CNRL 2015, figure 3.1-8). This figure provides a basis for understanding the expected fracturing of the formation associated with injection pressures in relation to the stress gradients.

1.4.4.2 Effects of Steam Injection on Stresses

HPCSS operations will cause a significant increase in reservoir pore pressure and a decrease in the effective stress, resulting in tensile fracturing or shear failure of the reservoir sands. The 4 to 6 m of Clearwater capping shale overlying the reservoir at Primrose is nearly impermeable compared to the reservoir sand. Due to thermal expansion and dilation of the reservoir sand, a large concentration of shear stresses develops at the sand and shale interface. This may lead to shear failure of the interface in the Clearwater capping shale. The high shear stress can cause casing failures in wells that penetrate the interface. Over the past 30 years, HPCSS operators in the Cold Lake area have experienced multiple casing failures within this zone. Casing failures, as well as induced shear or existing natural geological pathways within the Clearwater capping shale, may result in fluid migration from the Clearwater reservoir into the Grand Rapids Formation

CNRL uses a formation expansion index (FEI) to estimate the reservoir uplift at the top of the Clearwater capping shale at Primrose. FEI is defined as the steam injection VAF per unit of drainage area. The volume required for the reservoir pressure to reach the vertical in situ stress is called the fill-up volume, while the volume of steam injection after fill-up is called VAF. Before the FTS releases at Primrose, CNRL had injected steam to cause FEIs up to 140 cm at the top of Clearwater capping shale. This in turn can change the stress state in the overburden formations. In the Joli Fou and Westgate formations, where the initial minimum in situ stress is the vertical stress favouring hydraulically induced horizontal fractures, the increase in vertical stress directly above the horizontal steaming wells is much larger than the increase in the horizontal stress at the same location, such that the minimum horizontal and vertical in situ stresses approach each other (i.e., the difference between the vertical and horizontal stresses approaches zero). This makes vertical fractures more likely to develop. Vertical fractures increase the probability of bitumen emulsion flowing upward.

2 Potential Pathways

On October 21, 2013, Alberta Environment and Sustainable Resource Development (now Alberta Environment and Parks) issued an enforcement order that required CNRL to have its investigation findings reviewed by an independent third-party expert panel. The following sections of the report summarize CNRL's assessment of potential mechanisms and pathways for flow to surface, along with the interpretations and findings of the panel and the AER.

2.1 Enabling Conditions

CNRL identified four separate conditions that allowed for the release of bitumen emulsion from the Clearwater reservoir to surface; however, where a pre-existing open vertical conduit existed to bypass the requirement of an enabling condition, the four enabling conditions were not all necessary for an FTS event to occur. The four enabling conditions are as follows:

1) an excessive release of bitumen emulsion from the Clearwater reservoir into the next overlying permeable formation: the Grand Rapids Formation;
2) a hydraulically induced vertical fracture that propagated up to the top of the Grand Rapids Formation;
3) vertical pathways to facilitate fluid transfer through highly impermeable shales that have in situ stress states that usually favour horizontal hydraulic fracturing; and
4) an uplift of the overburden above the Clearwater reservoir that changed the stress in the overlying shale such that the minimum horizontal and vertical principal in situ stresses approached each other.

The panel agreed with the four enabling conditions described by CNRL. The panel submitted that three aspects to the four enabling conditions identified by CNRL were controllable:

1) the existence of a cased well or open-hole wellbore with a poor seal along at least a portion of its path;
2) excessive uplift generated by operational steaming in the Clearwater reservoir; and
3) excessive fluid volume released from the Clearwater reservoir into the Grand Rapids Formation.

The panel agreed with CNRL that not all the conditions were necessary for an FTS event to occur, but they further stated that CNRL had not provided adequate analyses of possible alternatives to CNRL's primary flow path elements, although much of the data to do so was present in CNRL's report. In particular, the approach had insufficiently addressed the impact of geological variability (such as natural discontinuities and variations in the in situ stresses) on the mechanisms controlling the flow paths.

We agree with both CNRL and the panel that the four enabling conditions are major factors for understanding the development of the FTS events. We also agree with both CNRL and the panel that the FTS events may have been created by events that did not necessarily include all four enabling conditions.

The following sections outline in more detail CNRL's findings, along with areas of specific agreement and critique from the panel and the AER.

2.2 Pathway Through the Clearwater Capping Shale (Enabling Condition 1)

The first enabling condition hypothesized by CNRL was "an excessive release of bitumen emulsion from the Clearwater reservoir into the next overlying permeable formation, the Grand Rapids Formation."

2.2.1 FTS Sites at Pad 74, 10-1, 10-02, and 2-22

CNRL believed that the FTS events at pad 74, 10-01, 10-02, and 2-22 were caused by the excessive release of bitumen emulsion from the Clearwater reservoir.

Monitoring systems in the field have shown that excessive bitumen emulsion releases from the Clearwater reservoir can be identified by multiwell injectivity events, which involves multiple wells experiencing sudden injection rate increases and pressure decreases. The excessive bitumen emulsion releases are also identified by regional pressure responses using observation wells in the overlying Lower Grand Rapids basal water sand. The observation wells can detect pressure responses over large distances, providing the ability to locate release events by performing pressure transient analysis of three or more observation well pressure responses (i.e., triangulation). An excessive release on its own may not cause a flow path to the surface to develop. Most releases from the Clearwater reservoir do not correlate to the FTS events. However, all four of the FTS events discussed in this section have been associated with some of the largest releases observed from the Clearwater reservoir. With respect to these large releases, CNRL estimated the volume of bitumen emulsion released from the Clearwater reservoir into the Grand Rapids Formation for the pad 74 and 10-01 events to be greater than 250 000 m^3, for the 10-02 event to be 180 000 m^3, and for the 2-22 event to be 250 000 m^3. Tables 3 and 4 summarize the pressure transient and Clearwater injectivity analysis, while figures 18 and 19 show the location of the corresponding Grand Rapids Formation release events for those four FTS sites.

The panel stated that PSSAs, the occurrence of injectivity events, and pressure monitoring wells responses in the Grand Rapids Formation could identify significant releases from the Clearwater reservoir to the Grand Rapids Formation. Pressure monitoring wells in the Grand Rapids Formation could triangulate the source location for excessive fluid releases. The panel agreed with CNRL that the location of larger PSSA features can be related to the triangulated location of excessive release of fluid. In addition to the failure of Clearwater capping shale, casing failures also have the ability to transfer large volumes of fluid from the Clearwater reservoir to the Grand Rapids Formation.

The panel stated that while the CNRL final report presented a wealth of steam injection and Grand Rapids pressure response monitoring data, the results did not clearly define which events corresponded to an excessive release of fluid into the Grand Rapids Formation and which were steam breakthroughs to a different portion of the Clearwater reservoir. As a result, the number of fluid releases into the Grand Rapids Formation was likely overstated.

We concur with both CNRL and the panel that the excessive releases of bitumen emulsion through the Clearwater capping shale is the first enabling condition of the FTS events and has occurred due to a failure of the caprock during HPCSS operations. Figure 20 is an FEI distribution at Primrose with FTS events on a per-well basis. The figure shows that FTS events are confined to the top 27% of this distribution. This indicates a correlation exists between FTSs and significant uplift-induced stress changes.

We believe that the Clearwater capping shale is being compromised during HPCSS operations at Primrose East. We believe that the injection pressures and steam volumes used by CNRL for Primrose East HPCSS operations have either activated existing fracturing and faulting of the Clearwater capping shale or altered the stress state enough to induce fracturing to enable releases of bitumen emulsion into the Grand Rapids Formation.

Table 3. Pad 74, 10-01, and 10-02 FTS pressure transient and Clearwater injectivity analysis summary (modified from CNRL 2015, table C.4-4).

Clearwater Formation Fluid Release Start Date	Closest Observation Well to Grand Rapids Formation Pressure Response	Exceed 200 kPa/d criteria?	Related Phases	Multiwell Clearwater Formation Injectivity/ Depressure	Multi B12 Well Response	Grand Rapids Formation Magnitude Index Normalized to 250 m*
11-Oct-2009	9-2	No	75/77/78	Yes	Yes	1
19-Nov-2009	9-2	No	74/75	Yes	Yes	1
6-Dec-2009	11-1	Yes	74/75/77/78	Yes	Yes	1
7-Jan-2010	11-1	Yes	74/75/77/78	No	Yes	2
5-Feb-2010	74C	No	77/78	No	Yes	1
18-Feb-2010	11-1	Yes	74/77/78	Yes	Yes	1
1-Mar-2010	11-1	No	74/75/77/78	Yes	Yes	1
29-May-2010	9-2	No	74/75	Yes	Yes	2
22-Jun-2010	11-1	No	74/75	Yes	Yes	2
11-Jul-2010	9-2	Yes	74/75	Yes	Yes	2
3-Nov-2010	11-6	Yes	77/78	Yes	Yes	2
2-Dec-2010	74OB2L	Yes	77/78	Yes	Yes	3
21-Jan-2011	74B	Yes	77/78	Yes	Yes	1
6-Mar-2011	74C	No	74/75/77/78	Yes	Yes	1
17-Apr-2011	9-2	Yes	74/75	Yes	Yes	4
23-May-2011	9-2	Yes	74/75	Yes	Yes	2
13-Mar-2012	9-2	Yes	74/75	Yes	Yes	2
14-Apr-2012	9-2	Yes	74/75	Yes	Yes	3
16-May-2012	74C	No	74/75/77/78	Yes	Yes	1
15-Jun-2012	74OB2U	No	74/75/77/78	No	Yes	1
7-Jul-2012	74OB2L	No	77/78	No	Yes	1

* Scale = 1: 0–500 kPa, 2: 500–1000 kPa, 3: 1000–1500 kPa, 4: 1500–2000 kPa, 5: 2000–2500 kPa.

Table 4. 2-22 FTS pressure transient and Clearwater injectivity analysis summary (modified from CNRL 2015, table C.4-3).

Clearwater Formation Fluid Release Start Date	Closest Observation Well to Grand Rapids Formation Pressure Response	Exceed 200 kPa/d criteria?	Related Phases	Multiwell Clearwater Formation Injectivity/ Depressure	Multi B12 Well Response	Grand Rapids Formation Magnitude Index Normalized to 250 m*
10-Aug-2012	2-27	No	93	Yes	Yes	1
21-Aug-2012	2-27	Yes	93	No	Yes	2
28-Aug-2012	4-22	Yes	95	Yes	Yes	1
11-Sep-2012	16-22	Yes	92/93	Yes	Yes	1
18-Sep-2012	P94 B12	No	92/93	No	Yes	1
6-Oct-2012	P94 B12	No	92/93	No	Yes	2
25-Oct-2012	14-23	No	92/93	Yes	Yes	1
23-Jan-2013	2-27	No	93/94	Yes	Yes	2
11-Mar-2013	4-22	Yes	93/94/95	Yes	Yes	4
7-May-2013	16-22	Yes	92/94/95	Yes	Yes	3
22-May-2013	14-23	No	92/94/95	No	Yes	1

* Scale = 1: 0–500 kPa, 2: 500–1000 kPa, 3: 1000–1500 kPa, 4: 1500–2000 kPa, 5: 2000–2500 kPa.

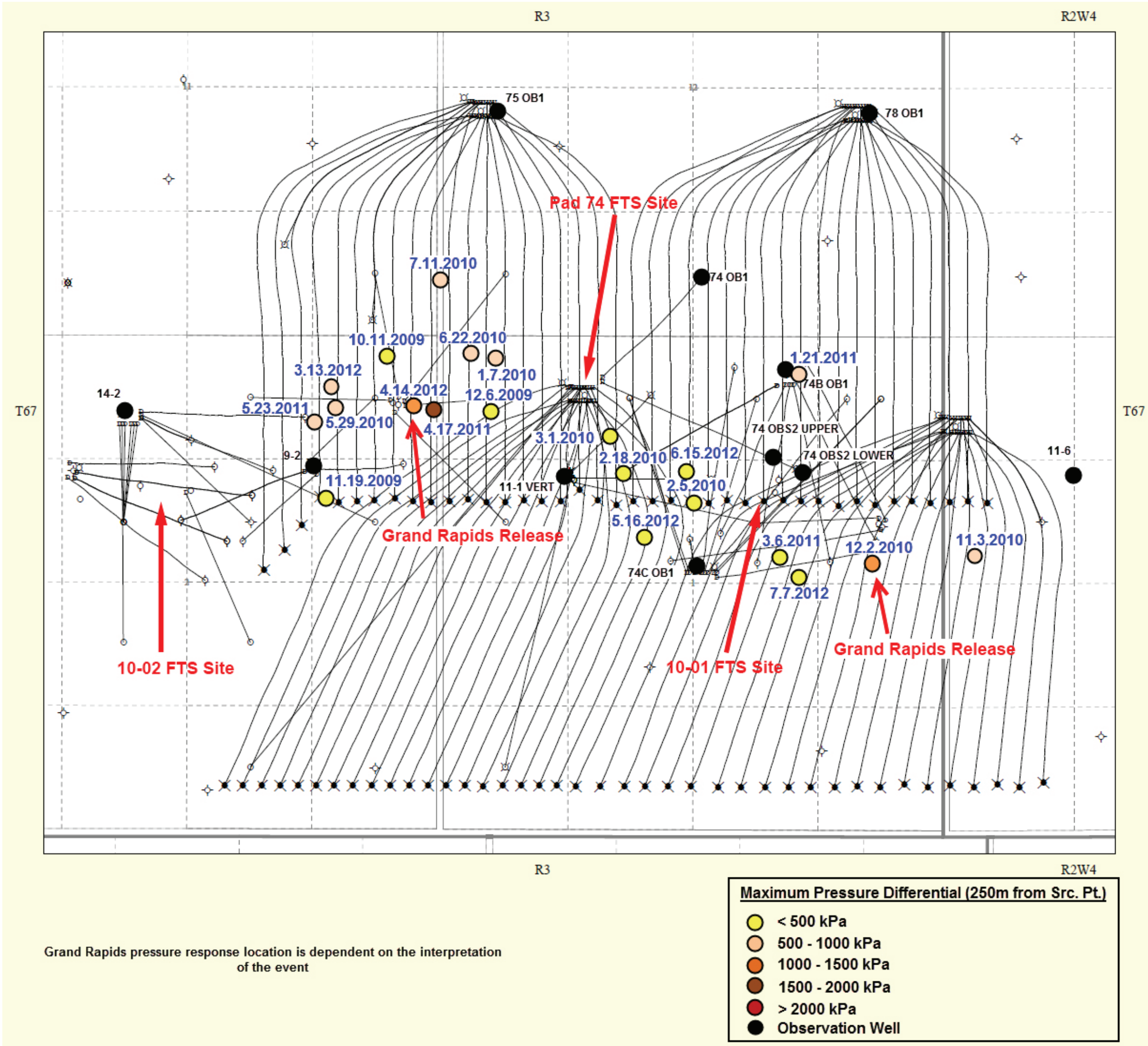

Figure 18. Location of Grand Rapids release events for pad 74, 10-01, and 10-02 sites (from CNRL 2015, figure 4.2-20).

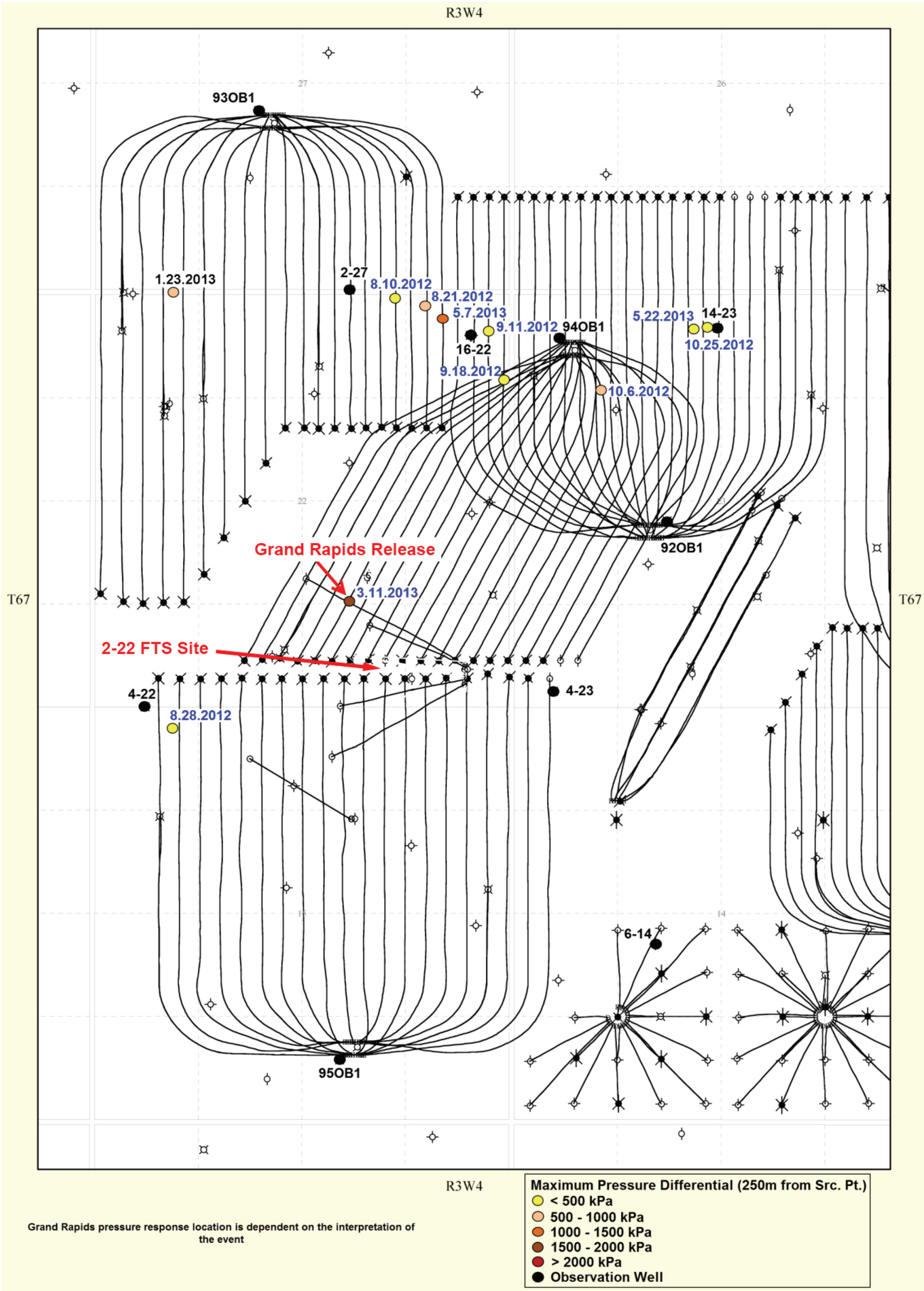

Figure 19. Location of Grand Rapids release events for 2-22 site (from CNRL 2015, figure 4.2-8).

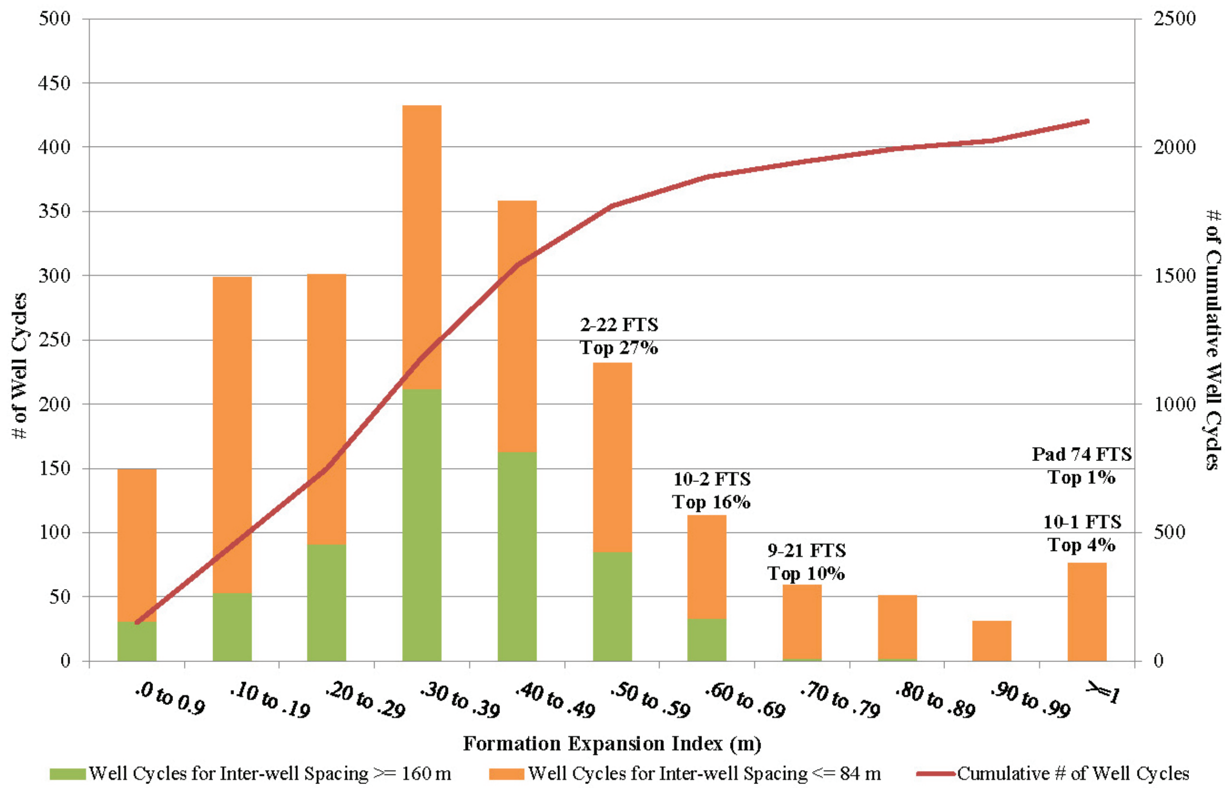

Figure 20. Primrose FEI distribution with FTS events in the highest 27% on per-well basis (from CNRL 2015, figure 1.3-4).

2.2.2 FTS Site 9-21

CNRL hypothesized that the 9-21 FTS did not originate from a release of bitumen emulsion through the Clearwater capping shale. Instead, CNRL stated that casing failures of the 1C21 and 4D21 wells at phase 21 most likely contributed to the 9-21 release, and the bitumen emulsion was directly released into the Colorado Group.

CNRL's investigation was unable to locate bitumen emulsion related to the 9-21 flow path in the Grand Rapids and Joli Fou formations. The deepest observed bitumen emulsion related to the FTS event was located in the Westgate Formation. Therefore, CNRL was of the view that a different flow mechanism may be present from the Clearwater reservoir through the Grand Rapids Formation.

The panel noted that although significant releases of bitumen emulsion were documented by CNRL to the north of the 9-21 event, extensive drilling between these locations and the 9-21 site was unable to locate any bitumen emulsion in the Colorado Group. Since there was no evidence of a flow path connecting the northern releases with the 9-21 event, this led to the association of the 9-21 FTS event with a casing failure on the phase 21 pad, with CNRL suggesting the 4D21 well had the casing break that put bitumen emulsion into the Westgate Formation.

We are not convinced that the 1C21 and 4D21 wells contributed to the 9-21 release. According to the casing failure reports submitted by CNRL to the AER, a pressure integrity test was conducted on the 1C21 well on July 6, 2006, after cycle 4 steaming operations, and no casing failure was detected. However, a casing failure was later detected at the 1C21 well on September 26, 2008, and was repaired on December 8, 2008, before beginning cycle 5. CNRL indicated that the liquid level in the wellbore had remained below the casing failure after July 6, 2006; therefore, bitumen emulsion loss to the formation is unlikely. In the case of the 4D21 well, CNRL did not detect any anomalies during HPCSS operations before the discovery of the casing failure in 2004. The last cycle of steaming on the 4D21 well was completed approximately ten years before the discovery of the 9-21 release. Any bitumen emulsion released through a casing failure of the 4D21 well would have been trapped in the Colorado Group for that time. The temperature of the trapped bitumen emulsion would have cooled to the original temperature of the Colorado Group, resulting in an increased viscosity and reduced mobility of the bitumen emulsion. In addition, the 4D21 well is more than a kilometre away from the 9-21 site. These considerations make it an unlikely source for the flowing bitumen emulsion discovered during the delineation drilling in the area between phase 22 and the 9-21 site.

Although the delineation drilling between the 9-21 site and phase 22 located to the north did not indicate the presence of a flow path connecting a bitumen emulsion release through the Clearwater capping shale in phase 22 as noted by the panel, we believe that this does not necessarily mean a flow path does not exist, especially given the limitations in the coverage of CNRL's delineation program in the vicinity of the 9-21 site and the discovery of flowing bitumen emulsion within the Westgate and Second White Specks formations located between the phase 22 wells and the 9-21 site.

We note that the southernmost six wells at phase 22 received steam injection from March to May 2013 with volumes of 130 000 m^3/well, and the 9-21 release was discovered on June 24, 2013. These large injection volumes resulted in large FEIs that were within the top 10 per cent of all FEIs at Primrose. This level of uplift combined with the PSSA identified immediately to the south of phase 22 is indicative of large volumes of emulsion being released from the Clearwater reservoir into the Grand Rapids Formation. Table 5 summarizes the 9-21 FTS pressure transient and Clearwater injectivity analysis, and figure 21 shows the location of the corresponding Grand Rapids Formation release events for the 9-21 site.

The three Grand Rapids Formation pressure monitoring observation wells as shown in figure 21 (wells PS22, 8-28, and 6B29) essentially form a straight line running from west to east through the centre of phase 22, which makes the interpretation of location using pressure transient analysis ambiguous. The April 22, 2013, release from the Clearwater reservoir into the Grand Rapids Formation identified by CNRL that occurred in the northern portion of phase 22 could have been caused by the steaming of the southernmost six wells.

As mentioned previously, during the delineation drilling in the area between phase 22 and the 9-21 site, flowing bitumen emulsion was discovered in the Colorado Group. The discovery of this flowing bitumen

Table 5. 9-21 FTS pressure transient and Clearwater injectivity analysis summary (modified from CNRL 2015, table C.4-5).

Clearwater Formation Fluid Release Start Date	Closest Observation Well to Grand Rapids Formation Pressure Response	Exceed 200 kPa/d criteria?	Related Phases	Multiwell Clearwater Formation Injectivity/ Depressure	Multi B12 Well Response	Grand Rapids Formation Magnitude Index Normalized to 250 m*
29-Mar-2012	8-28	No	22/23	Yes	Yes	3
12-Apr-2012	8-28	Yes	22	Yes	No	1
19-Apr-2012	8-28	No	22	Yes	Yes	1
1-Aug-2012	8-28	No	22	Yes	Yes	3
18-Mar-2013	8-28	No	22/23	Yes	Yes	3
22-Apr-2013	8-28	No	22	Yes	Yes	2

* Scale = 1: 0–500 kPa, 2: 500–1000 kPa, 3: 1000–1500 kPa, 4: 1500–2000 kPa, 5: 2000–2500 kPa.

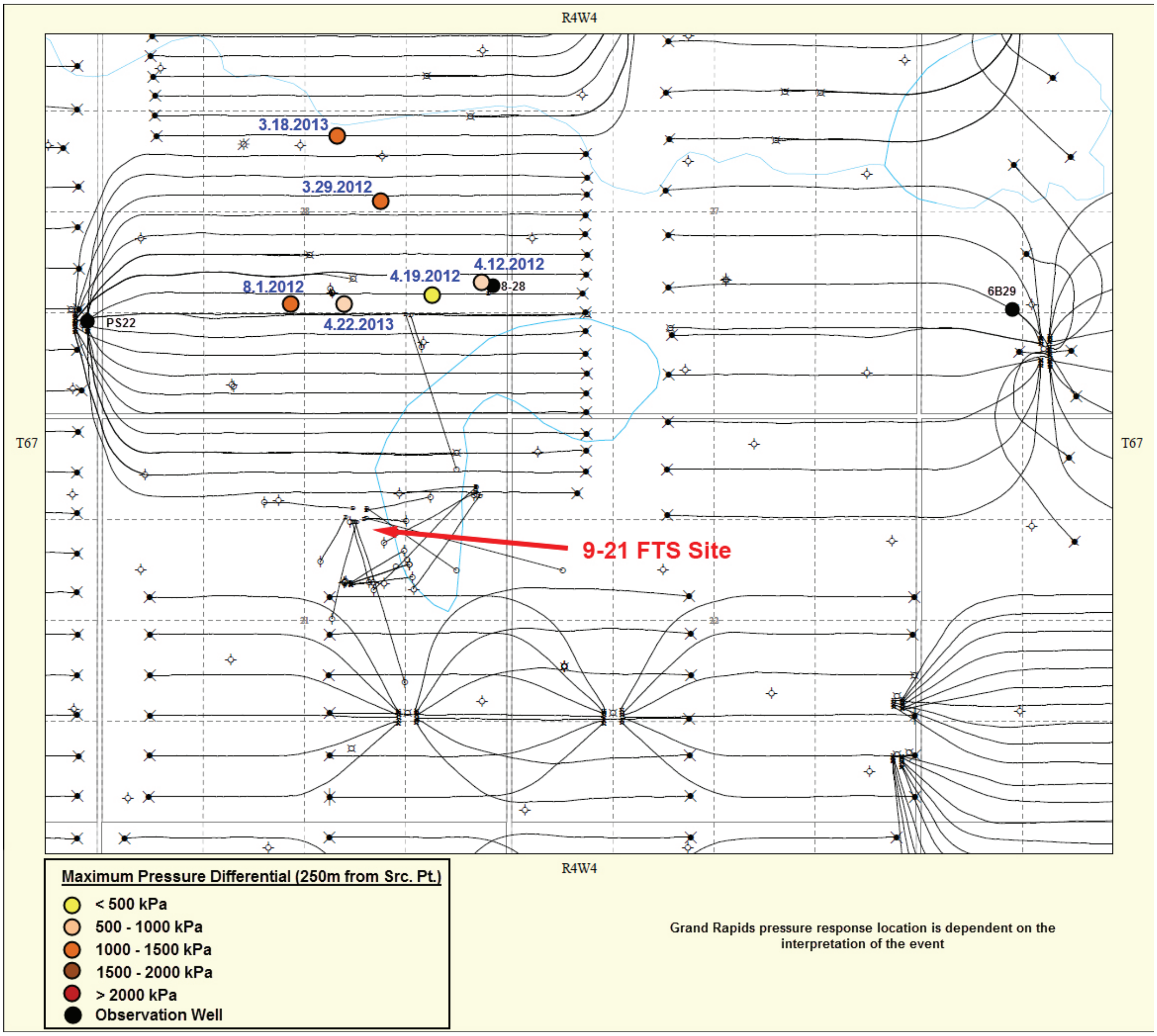

Figure 21. Location of Grand Rapids Formation release events for 9-21 site (from CNRL 2015, figure 4.2-33).

emulsion suggests that the FTS was likely caused by recent steaming. We believe that the 9-21 event more likely originated from a breach of the Clearwater capping shale due to the HPCSS operations at phase 22 in 2013 rather than from casing failures at the 1C21 and 4D21 wells.

2.3 Pathway Within the Grand Rapids Formation (Enabling Condition 2)

The second enabling condition hypothesized by CNRL was “a hydraulically induced vertical fracture that propagated up to the top of the Grand Rapids Formation.”

2.3.1 FTS Sites at Pad 74, 10-01, and 10-02

CNRL identified the pathway through the Grand Rapids Formation as being a vertical fracture caused by excessive bitumen emulsion released from the Clearwater reservoir. The general locations of the vertical fractures in the Grand Rapids Formation were identified by the PSSA. CNRL performed modelling to investigate the behaviour of hot bitumen emulsion released into a cool permeable water sand and found that the emulsion cooled quickly and resulted in a barrier to fluid flow, therefore inducing a vertical fracture. This barrier to flow (skin) caused the fracture to continue to propagate upwards through the Grand Rapids Formation when excessive volumes of bitumen emulsion were released from the Clearwater reservoir.

The panel agreed with CNRL; however, the panel submitted that geological variability provided another possible mechanism for enhanced fracture growth with smaller fluid release volumes when the overlying Grand Rapids Formation had a much smaller net thickness of water-saturated sand.

We agree with both CNRL and the panel that excessive bitumen emulsion releases from the Clearwater reservoir can overcome the ability of the Grand Rapids Formation to dissipate the pressure before fracturing upwards through the Grand Rapids Formation. The measured minimum horizontal in situ stress gradient in the Grand Rapids Formation is less than the vertical stress gradient, indicating that any induced fractures in this formation would be vertical. With respect to the panel’s alternative mechanism, the AER agrees that smaller volumes of bitumen emulsion would be required to hydraulically induce a vertical fracture in thinner water-saturated sand.

2.3.2 FTS Site 2-22

CNRL identified the pathway through the Grand Rapids Formation for the 2-22 FTS event as being a vertical fracture through the lower portion of the Grand Rapids Formation caused by the excessive bitumen emulsion released from the Clearwater reservoir. The vertical fracture then intersected the 7-22 wellbore, which had poor cement isolation in the Upper Grand Rapids Formation. CNRL was of the view that the 7-22 wellbore assisted in the propagation of the bitumen emulsion from the Upper Grand Rapids Formation into the Joli Fou Formation.

The panel agreed with CNRL.

Similar to the pad 74, 10-01, and 10-02 events, the AER agrees with both CNRL and the panel that excessive bitumen emulsion releases from the Clearwater reservoir contributed to the 2-22 FTS pathway in the Lower Grand Rapids basal water sand. We agree with both CNRL and the panel that the 7-22 wellbore possibly contributed to the propagation of bitumen emulsion upwards in the Upper Grand Rapids Formation.

2.3.3 FTS Site 9-21

CNRL hypothesized that the FTS event at site 9-21 was caused by the casing failure of at least one of wells 1C21 and 4D21.

The panel agreed with CNRL that the 9-21 FTS event was associated with a casing failure at phase 21.

We disagree and believe the 9-21 FTS event was caused by enabling condition 2 (“hydraulically induced vertical fracture”) resulting from a breach of the Clearwater capping shale inducing a vertical fracture in the Grand Rapids Formation. The flow path of the 9-21 event likely propagated through the Grand Rapids Formation due to HPCSS operations at phase 22 in 2013.

2.4 Pathway From the Upper Grand Rapids Formation into the Colorado Group (Enabling Condition 3)

The third enabling condition hypothesized by CNRL was “vertical pathways to facilitate fluid transfer through highly impermeable shales that have in situ stress states that usually favour horizontal hydraulic fracturing.”

CNRL acknowledged that there were a number of possibilities to explain the vertical pathways through the Joli Fou Formation and up to as high as the Westgate Formation. These possibilities included (1) wellbore pathways, which CNRL believed were the most likely and efficient way for fluid to travel vertically; (2) natural fractures and faults in the shales; and (3) vertical hydraulically induced fractures.

CNRL used both analytical and geomechanical models to investigate the stress changes in the Joli Fou Formation. The modelling results showed that the vertical stress at the base of the Joli Fou Formation approached the minimum horizontal stress (i.e., the difference between the stresses approached zero), and this made it possible for an induced vertical fracture in the Upper Grand Rapids Formation to penetrate into the Joli Fou Formation and propagate upwards.

The panel pointed out that a technical weakness of enabling condition 3 was the understanding of the termination of the vertical hydraulic fracture in the Grand Rapids Formation when it reached the base of the Joli Fou Formation. The panel stated that a vertical fracture in the Grand Rapids Formation will not necessarily be stopped by a stress contrast until it entered the new stress regime and propagated in a state of unstable equilibrium for some distance. It was not unreasonable that this could occur more than 10 m from the interface.

We note that HPCSS operations in the Clearwater reservoir can change the stress states in the overburden formations. In the formations from the Joli Fou to the base of the Second White Specks, the vertical stress directly above the HPCSS steaming wells increases significantly in comparison to the changes in the horizontal stress at the same location due to the formation uplift.

2.4.1 FTS Sites at Pad 74 and 10-01

CNRL identified the 9-1 wellbore as part of the pathway from the Upper Grand Rapids Formation into the Colorado Group for the pad 74 and 10-01 events. The Clearwater Formation release was located in close proximity to the 9-1 well, which suggested that the well played a role in these events.

In CNRL's view, the highest detected elevation of a bitumen emulsion in the VA9-1 OBS twinned well in proximity to the 9-1well was the Joli Fou Formation. The twinned well had the highest concentration of microimage resistive fractures within the upper Joli Fou Formation. The 9-1 wellbore is situated northeast of the PSSA. When combining the highest detected elevation of bitumen emulsion with the proximity to the Grand Rapids Formation flow path, CNRL was of the view that the 9-1 wellbore provided the FTS vertical pathway through the Joli Fou Formation.

CNRL also provided an alternative scenario in which no wellbore may have been involved in the transfer of fluid into the Lower Colorado Group. A Grand Rapids Formation hydraulically induced vertical fracture connected with a major fault in the First White Specks Member that allowed fluid to propagate to the level of the first bitumen emulsion appearance. Delineation drilling at the pad 74 and 10-01 sites did not confirm the activation of the fault, but CNRL stated that it was still a possibility.

The panel pointed out that there was no data from the 9-1 well to support inadequate placement of cement, and thus there was no compelling evidence for a flow path at this well. The panel believed a stair-stepping mechanism was a possible alternative to a wellbore and was consistent with the data. This would in part have resulted from fractures being intersected and enlarged by fluids flowing upwards at high pressures from the Grand Rapids Formation. With respect to CNRL's alternative scenario, the panel submitted that CNRL discounted the role of the faults because one was intersected by a well which did not encounter bitumen emulsion at that location. The panel stated that there should be no expectation that the entire surface of a fault was uniform and should have been involved over its entirety as a flow path element. In the opinion of the panel, it would be extremely fortuitous for a single well to intersect a bitumen trace at a fault that was a flow path element.

As mentioned in section 1.2.4, the process of burial, mountain building, glacial loading and unloading, and local salt dissolution at Primrose East developed fractures and faults and local overthickening of the Colorado Group over the salt dissolution area, which may limit the ability of these shales to prevent vertical fluid migration to surface. Although a stair-stepping pathway is not supported by field observation (the majority of oil-filled fractures from core samples in the Westgate, Fish Scales, and Belle Fourche formations were found to have low dip angles), we believe that the pathway from the Upper Grand Rapids

Formation into the Colorado Group for the pad 74 and 10-01 events was most likely through natural fractures, faults, or vertical hydraulically induced fractures in the Joli Fou Formation.

2.4.2 FTS Site 10-02

CNRL identified the 9-2 wellbore as the pathway from the Upper Grand Rapids Formation into the Colorado Group for the 10-02 event based on the following considerations:

- The Clearwater Formation fluid release was located in proximity to the 9-2 wellbore, which suggested that the well played a role in the 10-02 event. Fluid samples recovered from perforations in the Grand Rapids, Joli Fou, and Viking formations contained bitumen emulsion. Packer isolation tests indicated pressure communication behind the casing in the Westgate Formation.
- CNRL identified a temperature log anomaly near the top of the Grand Rapids Formation, and the elevated temperature profile extended through the Joli Fou Formation and into the lower Westgate Formation. Perforations in the 9-2 wellbore from the Grand Rapids to the Viking formations encountered bitumen emulsion behind the pipe. Cement bond logs showed channeling behind production casing in the Lower Colorado Group.
- During steam injection, microseismic events were detected in the Upper Grand Rapids and lower Joli Fou formations. These microseismic events spread out laterally at the Grand Rapids and Joli Fou formation interface, which suggested that the vertical progression of the bitumen emulsion flow had stopped. Above the interface in the Joli Fou Formation, the microseismic events followed in close proximity to the 9-2 wellbore, suggesting that the bitumen emulsion had migrated up the wellbore.

Therefore, CNRL's view was that the 9-2 wellbore served as the pathway for migration of bitumen emulsion from the Upper Grand Rapids Formation up to at least as high as the Viking Formation.

CNRL also provided an alternative scenario where no wellbore may have been involved in the transfer of fluid into the Lower Colorado Group. CNRL stated that the potential for an FTS flow path vertically up through the Joli Fou Formation using natural fractures and faults cannot be dismissed; however, the data collected did not appear to support this possibility.

The panel indicated that the overall interpretation by CNRL missed some points, and those points made the role of the 9-2 well in the FTS event at the 10-2 site much less compelling. Those points included the mismatch of the timing between the passive seismic events and the FTS event, the lack of annular space around the full circumference of the well to support the flow required to develop the FTS, and the lack of indication of fluid flow behind casing based on the temperature log. However, the panel did not provide an alternative flow path.

We agree with the panel that the lack of annular spacing around the full circumference of the 9-2 wellbore does not support CNRL's interpretation that the well played a role in the 10-2 event. We note that only a trace of bitumen emulsion was detected in upper Joli Fou and Viking formations, but no bitumen was detected in the Westgate Formation, which indicates that the pathway from the Upper Grand Rapids Formation into the Colorado Group for the 10-02 FTS is most likely through natural fractures, faults, or vertical hydraulically induced fractures in the Joli Fou Formation.

2.4.3 FTS Site 2-22

The Clearwater Formation release was located in close proximity to the 7-22 wellbore, which suggested to CNRL that the well played a role in the 2-22 event. CNRL verified a gap without cement within the 7-22 wellbore in the Colorado Group during a re-entry operation of the well. Based on the high emulsion flow rate encountered in the Westgate Formation (up to 200 L/min) and that the 7-22 well is within the triangulation area interpreted from pressure transient analysis, CNRL believed that this wellbore directly contributed to the flow path of bitumen emulsion from the Grand Rapids Formation, bypassing the lowest part of the Colorado Group.

The panel agreed with CNRL that there was strong evidence that the 7-22 well was a conduit through the Joli Fou Formation.

We believe that the 7-22 wellbore possibly played a role in contributing to the flow path of bitumen emulsion from the Grand Rapids Formation into the Colorado Group. However, another possible alternative flow path is through natural fractures or faults in the shales or vertical hydraulically induced fractures into the Colorado Group. The high pressure and high emulsion flow rate encountered in the Westgate Formation could also be explained by a fracture filled with high-pressure bitumen emulsion intersecting the 7-22 wellbore.

2.4.4 FTS Site 9-21

CNRL believed that a casing failure of at least one of the 1C21 and 4D21 wells at phase 21 directly caused the Clearwater reservoir bitumen emulsion to be released into the Colorado Group.

The panel agreed with CNRL that the 9-21 event was associated with a casing failure at phase 21 that put bitumen emulsion from the Clearwater reservoir into the Westgate Formation within the Colorado Group.

In our view, there is insufficient supporting evidence for the casing failures of the 1C21 and 4D21 wells at phase 21 being the source of the bitumen emulsion in the Colorado Group. We believe that the pathway to the Colorado Group for the 9-21 release was most likely from the bitumen emulsion released into the Grand Rapids Formation in phase 22. The bitumen emulsion then migrated up through natural fractures, faults, or vertical hydraulically induced fractures in the Joli Fou Formation to the Westgate Formation.

2.5 Overburden Uplift (Enabling Condition 4)

The fourth enabling condition hypothesized by CNRL was “an uplift of the overburden above the Clearwater reservoir that changed the stress in the overlying shale, such that the minimum horizontal and vertical principal in situ stresses approached each other.”

When vertical stress is low relative to horizontal stress, it is more likely that the fractures induced by steaming operations will be horizontal simply because it’s physically easier for the rock to split up and down. This is desirable because vertical fractures make it more likely that emulsion could flow upwards, potentially to surface.

Conversely, when the vertical stress is high relative to the horizontal stress, the induced fractures are more likely to orient vertically. And when the stresses “approach each other,” meaning that the difference between them approaches zero, one can no longer predict whether the fractures will be vertical or horizontal.

CNRL hypothesized that in the case of all five FTS events, once a flow path was established through the Joli Fou Formation (enabling condition 3), the path followed a low-angle path from the Westgate Formation to the base of the Second White Specks Formation. They hypothesized that steaming operations in the Clearwater reservoir caused overburden uplift, altering the in situ stresses in the overburden (as described above) such that low-angle paths began to form in the Westgate Formation, which have been observed in core. For the 9-21 event specifically, they believed steaming at phase 22 wells may have caused an uplift of the overburden, altering the in situ stresses in the Colorado Group to cause the bitumen emulsion in the Westgate Formation to migrate upwards.

The panel stated that CNRL’s investigation was limited and inadequate to characterize possible spatial variability or acknowledge the simple standard deviation in stress magnitude and rock property values determined by the analysis. The panel further pointed out that while stress variations can be estimated using an analytical model of stress changes due to overburden uplift, this approach will not work without sufficient InSAR (interferometric synthetic aperture radar; used to measure surface deformation) data to verify the overburden uplift and recovery.

Concerns aside, we agree in principle with CNRL that once a flow path passed through the Joli Fou Formation into the Westgate Formation, it could follow natural fractures with low dip angles.

2.6 Pathway From the Colorado Group to Surface

2.6.1 FTS Sites 10-1, 10-2, 2-22, and 9-21

Based on the FTS delineation drilling results, CNRL hypothesized that once the flow path passed through the Westgate, Fish Scales, and Belle Fourche formations and arrived at the base of the Second White Specks Formation, the pathway turned to vertical and travelled all the way through the Second White

Specks, Niobrara, Lea Park formations, and the Quaternary strata to the surface. CNRL indicated that this was supported by the delineation drilling, which found no bitumen emulsion or significant chloride concentration in the Quaternary strata aside from low chloride and dissolved hydrocarbon concentrations within close proximity to the fractures themselves. In addition, the absence of bitumen emulsion in the vertical delineation wells near the surface fractures indicated that the pathways in these formations were largely vertical.

The panel was of the view that in and above the Niobrara Formation, field evidence showed that flow through induced or natural vertical fractures was a clear component of all the FTS events. This showed that if bitumen reached an area where the vertical in situ stresses began to exceed the minimum horizontal in situ stresses, and fluid pressure was sufficient to enable flow to surface, the bitumen emulsion expression at surface would occur directly above that location in the Niobrara.

We agree with both CNRL and the panel on this portion of the pathway. The measured minimum horizontal stresses in the upper portion of the Niobrara Formation favours vertical fractures as shown in figure 17.

2.6.2 Pad 74 FTS Site

CNRL hypothesized that the bitumen emulsion released at the pad 74 site used the 1A74 wellbore to flow to surface passing through the Niobrara and Lea Park formations and the Quaternary strata. CNRL indicated that this was supported by the perforation study that observed bitumen emulsion along the wellbore from the Niobrara into the Lea Park. In CNRL's view, together with the 1A74 wellbore, bitumen emulsion flowed to the surface through induced or natural vertical fractures or faults in the Niobrara and Lea Park.

The panel did not provide its view whether the 1A74 wellbore contributed to the pad 74 event. However, the panel's view was that in and above the Niobrara Formation, field evidence showed that flow through induced or natural vertical fractures was a clear component of all the FTS events.

For the pad 74 event, we agree with the panel that the pathway in and above the Niobrara Formation favours vertical fractures.

2.7 Conclusions on Pathways

Table 6 summarizes the general views of CNRL, the panel, and the AER on the potential pathways.

2.7.1 Views of CNRL

Excessive steam volumes can alter the stress state enough to induce fracturing to enable releases of bitumen emulsion into the Grand Rapids Formation (enabling condition 1).

Table 6. Summary of pathways.

Pathway	FTS Event	CNRL	Panel	AER
Through Clearwater Capping Shale	Pad 74, 10-1, 10-2, and 2-22	Breach of Clearwater capping shale	Breach of Clearwater capping shale	Breach of Clearwater capping shale
	9-21	Bypass by casing failures at 1C21 and/ or 4D21	Bypass by a casing failure	Breach of Clearwater capping shale
Within Grand Rapids Formation	Pad 74, 10-1, and 10-2	Induced vertical fractures	Induced vertical fractures	Induced vertical fractures
	2-22	Induced vertical fracture / bypass by the 7-22 wellbore	Induced vertical fracture / bypass by the 7-22 wellbore	Induced vertical fracture / bypass by the 7-22 wellbore
	9-21	Bypass by casing failures at 1C21 and/ or 4D21	Bypass by a casing failure	Induced vertical fracture
Grand Rapids Formation to Colorado Group	Pad 74 and 10-1	Inadequate placement of cement in the 9-1 wellbore	Stair-stepping mechanism via natural discontinuities and induced fractures	Natural fractures/ faults and/or vertically induced fractures
	10-2	Inadequate placement of cement in the 9-2 wellbore	9-2 wellbore not compelling	Natural fractures/ faults or vertically induced fractures
	2-22	Bypass by no cement plug in the 7-22 wellbore	Bypass by no cement plug in the 7-22 wellbore	Bypass by no cement plug in the 7-22 wellbore or natural fractures/faults or vertically induced fractures
	9-21	Casing failures at 1C21 and/or 4D21	Casing failure	Natural fractures/ faults or vertically induced fractures
Colorado Group to Surface	10-01, 10-02, 2-22, and 9-21	Vertical natural or induced fractures	Vertical natural or induced fractures	Vertical natural or induced fractures
	Pad 74	1A74 wellbore	Vertical natural or induced fractures	Vertical natural or induced fractures

The hot bitumen emulsion released into a cool permeable water sand cooled quickly and resulted in a barrier to fluid flow, thereby inducing a vertical fracture. The barrier to flow caused the fracture to continue to propagate upwards through the Grand Rapids Formation when excessive volumes of bitumen emulsion were released from the Clearwater reservoir (enabling condition 2).

Although CNRL's view was that wellbore pathways were the most likely and efficient way for bitumen emulsion to travel vertically, CNRL acknowledged that natural fractures and faults in the shales, and hydraulically induced vertical fractures cannot be dismissed (enabling condition 3).

A significant uplift in the overburden formations changed the stress in the Colorado Group such that the minimum horizontal and vertical principal in situ stresses approached each other (enabling condition 4). This condition makes it more likely that induced fractures will orient vertically, and vertical fractures increase the likelihood of bitumen emulsion flowing upward.

A correlation existed between FTS events and significant uplift of the overburden formations.

2.7.2 Views of the Panel

The panel agreed that the four enabling conditions identified by CNRL were major factors for understanding the development of the FTS events at Primrose. Of the enabling conditions identified by CNRL, the panel considered that three aspects were controllable:

- the existence of a cased well or open-hole wellbore with poor sealing along at least a portion of its path;
- excessive uplift generated by operational steaming of the Clearwater reservoir; and
- excessive fluid volume released from the Clearwater reservoir into the Grand Rapids Formation.

The panel submitted that CNRL's approach had insufficiently addressed the impact of geological variability, such as natural discontinuities and variations in the in situ stresses on the mechanisms controlling the flow paths. CNRL's approach had also insufficiently explored the mechanism of failure and conductivity variation of the natural discontinuities in the presence of high pore pressure and modified in situ stresses. The panel stated that uncontrollable aspects to the enabling conditions such as the propensity for hydraulic fractures to be vertical in the Grand Rapids Formation and natural fracture and fault distributions in the Colorado Group also need to be sufficiently understood to properly assess operational risks. The panel also stated that naturally occurring geological features may be of particular importance at Primrose East where the formations have been affected by salt dissolution and four of the five FTS events have occurred.

2.7.3 Views of the AER

We believe that all five FTS events were caused by excessive steam volumes, along with an open conduit (wellbore or natural fracture or fault) or hydraulically induced vertical fractures. For the pad 74, 10-01, 10-02, and 2-22 events at Primrose East, our view is that geological variability and weaknesses exist, which were caused by structural deformation of the overlying sediments due to salt dissolution of the Prairie Evaporite Formation.

The 2-22 event is the only one that we believe a wellbore possibly contributed to the propagation of bitumen emulsion upwards from the Upper Grand Rapids Formation into the Colorado Group. Our view is that the 9-21 event was most likely caused by the large volume of steam injected in 2013 at the southernmost six wells at phase 22.

3 Regulatory Response

3.1 Interim Measures

On June 14, 2013, in response to the 10-1, 10-2, and 2-22 events, we ordered the suspension of all steaming operations in Primrose East. On July 17, 2013, after the 9-21 event was discovered, we further ordered the following:

- No steaming was permitted within 1000 m of the 9-21 site.
- Before beginning any steam injection, a risk assessment of wellbore integrity and a mitigation plan for wellbores with integrity concerns in the vicinity of the injection pad must be submitted to the AER for review.
- For Primrose North and South:
  - The total volume of injected steam had to be reduced across the board from previous practices.
  - The VAF was not permitted to increase from cycle to cycle.
  - When steaming in waves, the volume must be reduced at the edges (tapered) to minimize stress contrast.
- In order to identify fluid release events into the Grand Rapids Formation, monitoring protocols were enhanced:
  - If the pressure in the Lower Grand Rapids basal water sand increased by more than 200 kPa in a 24 hour period from the steaming pad area observation wells, CNRL must notify the AER.
  - The total pressure in the Lower Grand Rapids basal water sand must never increase past 60% of its fracture closure pressure.
- Should a multiwell injectivity event be detected, CNRL must do the following:
  - Reduce steam injection to a trickle rate and wait for pressure in the Clearwater reservoir to recover.
  - If the pressure in the Clearwater reservoir of the affected wellbores does not recover within 48 hours, CNRL must initiate flow back.

Subsequent to these letters, additional measures were also put into place:

- CNRL must apply for each and every cycle at Primrose.
- For new phases at Primrose North and South:
  - We required that before commercial production, two commissioning (“warm-up”) cycles be run to condition the reservoir, the intention being to create an environment where horizontal fractures are more likely.

- We restricted the FEI of first-cycle steaming to between 14 and 19 cm (instead of historical FEIs of as much as 140 cm).
- CNRL was not permitted to increase the VAF from cycle to cycle.

- For existing phases at Primrose North and South:
  - We restricted the FEIs of most cycles to less than 25 cm with seven exceptions, where FEIs ranged from 26 to 37 cm.
  - We restricted the VAFs of most cycles to less than 6% of the initial pore volume with thirteen exceptions, where VAFs were restricted to between 7% and 9.1%. (Historically, CNRL has had VAFs exceeding 20% of initial pore volume.)
- At Primrose East we permitted operations at areas 1 and 2 with the following limitations:
  - Steamflood at Area 1: Maximum bottomhole pressure was restricted to between 3.7 and 4.1 megapascals (MPa). The Lower Grand Rapids basal water sand must be monitored, and should the pressure increase more than 20 kPa in a 24 hour period, they must notify the AER.
  - Low-pressure CSS at Area 2: Maximum bottomhole pressure was restricted to 7 MPa. The Lower Grand Rapids basal water sand must be monitored, and should the pressure increase more than 50 kPa in a 24 hour period, they must notify the AER.

3.2 Measures Proposed by CNRL

CNRL proposed the following mitigation measures for future operations at Primrose:

- For new phases, CNRL would conduct commissioning cycles before commercial production to promote an environment where horizontal factures are more likely. The FEI limits proposed by CNRL for the commissioning cycles are provided in table 7.

Table 7. CNRL's proposed FEIs for commissioning cycles.

	East of Salt Dissolution Edge	West of Salt Dissolution Edge
Commissioning Cycle 1 FEI (cm)	9	13
Commissioning Cycle 2 FEI (cm)	13	18
Commissioning Cycle 3 FEI (cm)	18	N/A

- All commercial cycles would be limited to an FEI of 25 cm. The basis for CNRL proposing an FEI of 25 cm was that the minimum FEI associated with an FTS event was 50 cm, and CNRL subsequently applied a safety factor of two to the 50 cm.

- The pressure observation systems in the Lower Grand Rapids basal water sand would be in place. CNRL will respond to any abnormal Grand Rapids Formation pressure increases and multiwell Clearwater Formation injectivity events. In the event of a multiwell injectivity event, CNRL proposed to do the following:
  - Reduce steam injection to trickle rates and wait for pressure in the Clearwater to stabilize.
  - Notify the AER within 24 hours.
  - If injection pressures of the affected wellbores do not stabilize within 48 hours, initiate flow back to depressurize the Clearwater reservoir.
- Before beginning any steam injection, CNRL proposed to conduct a risk assessment of wellbore integrity and mitigate any wellbores with integrity concerns.

3.3 Regulatory Response

As previously discussed, the exact pathways that allowed the bitumen to flow to surface were not definitively determined. As a result, any controls imposed must be sufficient to account for as many different pathways as possible. There are both proactive and reactive controls. Proactive controls set up-front limits on pressures and volumes in attempt to minimize the likelihood of another event. Reactive controls focus on monitoring and define what response is required should a threshold be exceeded.

The following controls supersede those described in the previous sections and apply to all Primrose operations, effective immediately:

- Before commercial production, three commissioning (“warm-up”) cycles limited to an individual well FEI of 13 cm must be run at new pads to condition the reservoir, the intention being to create an environment where horizontal factures are more likely.
- The FEI of each well for all HPCSS cycles must be less than 25 cm.
- When steaming in waves, the volume must be tapered at the edges. That is, the VAF at the two edge rows of the wave must be reduced by at least 10% relative to the adjacent row.
- All steaming operations must have complete Lower Grand Rapids basal water sand pressure monitoring coverage over the drainage area of each phase. Because of the geological variability of the Lower Grand Rapids water sand, monitoring networks must be designed based on area-specific properties of the deepest water sand within the Lower Grand Rapids Formation.
- Should the pressure in the Lower Grand Rapids basal water sand ever increase by more than 200 kPa in a 24 hour period, CNRL must notify us.
- The pressure in the Lower Grand Rapids basal water sand must never exceed 60% of the Lower Grand Rapids fracture closure pressure.

- Should CNRL experience a multiwell injectivity event, they must do the following:
  - Reduce steam injection to trickle rates and wait for pressure in the Clearwater reservoir to stabilize.
  - Notify us within 24 hours.
  - If injection pressures of the affected wellbores do not stabilize within 48 hours, initiate flow back to depressurize the Clearwater reservoir.
- Before beginning any steam injection, a risk assessment of the integrity of wellbores within 1000 m of steaming wells must be conducted, and any wellbores with integrity concerns be remediated.
- Historically, VAF may have been underestimated because of the difficulty in reliably inferring the reservoir pressure. To ensure consistency, CNRL is required to calculate VAF based on the pressure at the wellhead. The reservoir is to be considered “full” when the pressure at the wellhead reaches the vertical in situ stress of the Clearwater reservoir, adjusting for friction loss.

We are also instituting additional controls in specific contexts. All the above requirements apply in these contexts as well.

3.3.1 Operations Within 1000 m of Any FTS Site

- No HPCSS operations are permitted within 1000 m of any FTS site. All other future operations are restricted to hydrostatic pressures.
- Should the pressure in the Lower Grand Rapids basal water sand ever increase by more than 20 kPa in a 24 hour period, CNRL must notify us.

3.3.2 Operations Within 1000 m of or East of the Salt Dissolution Edge

- CNRL must continue to apply for each and every steam injection cycle.
- For new phases, at least three commissioning cycles are required, during which the individual well FEI must be no greater than 13 cm.
- Should the pressure in the Lower Grand Rapids basal water sand ever increase by more than 50 kPa in a 24 hour period, CNRL must notify us.

3.3.3 Operations More Than 1000 m West of the Salt Dissolution Edge

- For new phases:
  - Three commissioning cycles are required, during which the individual well FEI must be no greater than 13 cm.
  - The FEI for each well in any commercial cycle must be no greater than 25 cm.
  - In addition to the previously outlined monitoring threshold of 200 kPa in a 24 hour period, should the pressure increase by 50 kPa or more in a 24 hour period, CNRL must document the events.
- In all areas where individual well FEIs were previously 50 cm or greater:
  - The FEI for each well in any commercial cycle must be no greater than 25 cm.
  - The Lower Grand Rapids basal water sand pressure threshold is lowered to 50 kPa over a 24 hour period.
- For areas where the net bitumen pay thickness (not the gross sand thickness) is less than 10 m:
  - The FEI for each well in any commercial cycle must be no greater than 20 cm.
  - In addition to the previously outlined monitoring threshold of 200 kPa in a 24 hour period, should the pressure increase by 50 kPa or more in a 24 hour period, CNRL must document the events.

Figure 22 shows the different areas of operations where the above requirements apply relative to the salt dissolution edge interpreted by CNRL.

4 References

AER (Alberta Energy Regulator). 2013. *ERCB Investigation Report: Primrose East Bitumen Emulsion Release, January 3, 2009*. Calgary, AB: Alberta Energy Regulator, 28 p.

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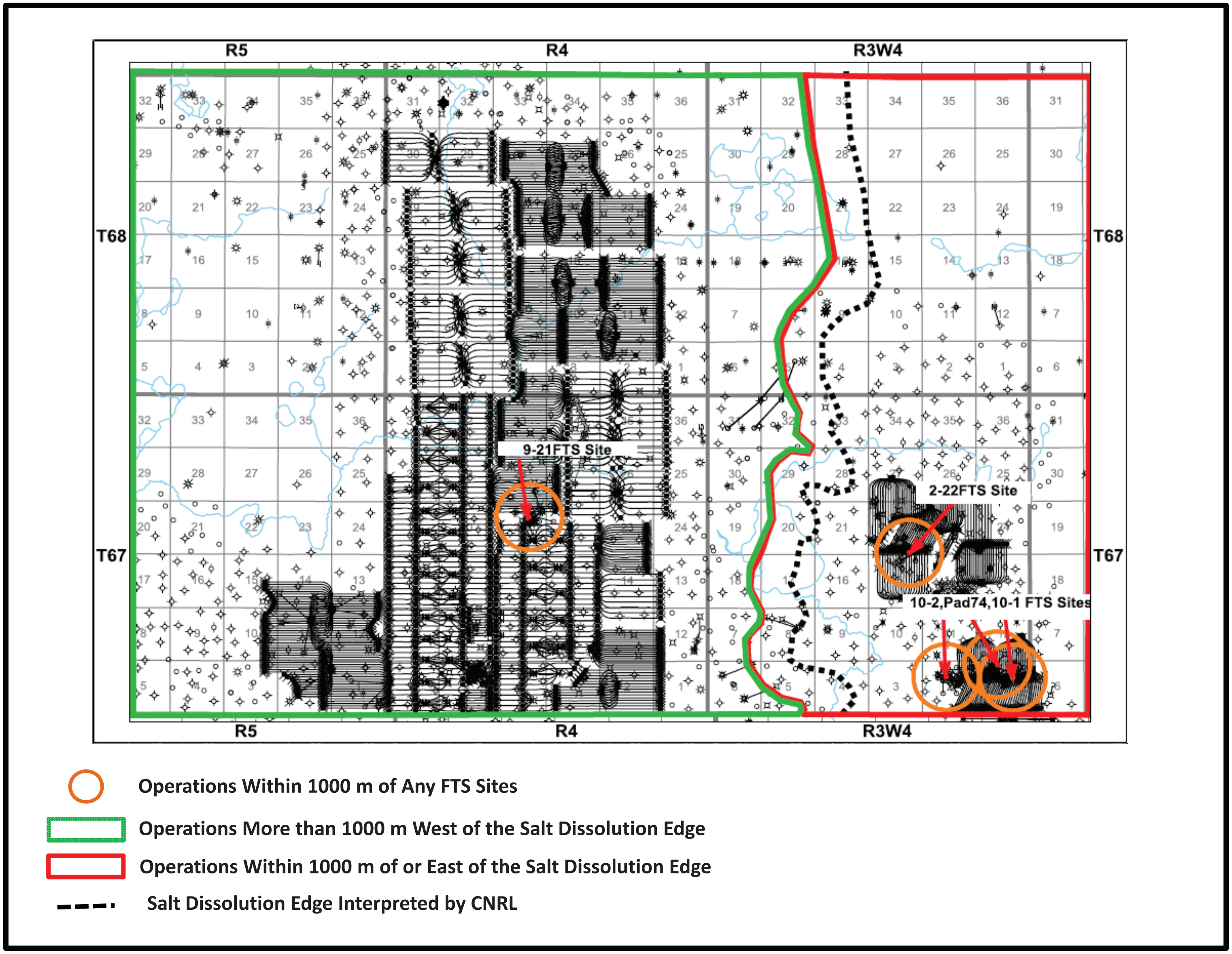

Figure 22. Different areas of operations where the requirements apply relative to the interpreted salt dissolution edge.

Appendix 1 Glossary

commercial cycle	A cycle of high-pressure cyclic steam stimulation (HPCSS) operations consisting of an injection phase and a production phase.
commissioning cycle	An HPCSS cycle that precedes commercial cycles, with limited steam injection volumes, designed to condition the reservoir by increasing its minimum horizontal in situ stress to promote horizontal fractures.
formation expansion index (FEI)	Defined as the volume above fill-up per unit of drainage area. This number estimates the uplift at the top of the capping shale created by the injected steam. Because the drainage area is known and fixed, the FEI is used as a constraint on volume above fill-up.
fracture closure pressure	The minimum pressure necessary to hold an existing fracture open. Below this pressure, existing fractures will close and new fractures will not form.
friction loss	The loss of pressure as a result of resistance as fluid moves along the inside wall of a well.
initial pore volume	Defined as the initial volume of the pores, or voids, within a porous material. This is the space to contain the injected steam within a reservoir.
injectivity event	An abrupt drop in reservoir pressure, along with a corresponding increase in the steam injection rate in a well.
multiwell injectivity event	This occurs when multiple wells adjacent to each other experience injectivity events.
pad	A surface lease site where a group of wells are drilled from and into the target reservoirs for the purpose of producing hydrocarbons.
phase	A subsurface drainage area associated with one or more surface well pads.

salt dissolution edge	The edge from which salt in the Prairie Evaporite Formation has been slowly dissolving due to water flow, resulting in variable deformation of overlying sediments. This edge is interpreted based on limited available geological information and could be subject to change with new drilling.
uplift	The upward displacement of a formation.
volume above fill-up (VAF)	The volume of steam injected beyond the amount needed to reach vertical in situ stress.