Panny LEAD Pilot Project
(Low-Pressure Electro-Thermally Assisted Drive)

IETP Project Approval No. 06-095

Final Report

June 2018

Revised Feb 2019

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1 Summary of Project

1.1 Report Abstract

The Panny LEAD (Low-Pressure Electro-Thermally Assisted Drive) Pilot project was conducted in the W½-34-094-07W5 Panny area within the Peace River Oil Sands Area. The Pilot surface location was at 13-34-94-7W5. This Pilot project evaluated the potential of a low-pressure process that utilizes downhole electric heaters combined with water and/or solvent injection to recover bitumen from the Bluesky formation. This Bluesky formation has an overlying gas cap that had been produced, and so exhibits depleted pressure. This technology has the potential to be commercialized in both the Panny area as well as many other bitumen/heavy oil reservoirs in Alberta. This is the final report.

Stage 1 Pilot operations Cyclic Heat Stimulation (CHS Test) started on October 15, 2015 with the commencement of reservoir heating ('first heat'). First cycle production started March 01, 2016, three production cycles were completed in 2016, and the fourth and final production cycle started Dec 05, 2016 and ended May 06, 2017. Observation well pressures and temperatures continued to be monitored until December 2017.

2 Project Status

2.1 Project Team:

Linda McKean,	VP, Production and Development
Ryan Roen,	Manager, Eastern Area Development
Peter Oyebanji,	Reservoir Engineering Specialist
Lloyd Kuzmyn,	Senior Staff Geoscience Specialist
Bob Tone,	Senior Production Engineer
John Sharkey,	Completions Superintendent
Matt Donegan,	Manager, Facilities & Operation Compliance
Jody Tangedal,	Production Superintendent

2.2 **Pilot Objectives**

The Pilot objectives were as follows:

- Demonstrate the ability to reduce the viscosity of the bitumen within the Bluesky formation with the use of electric cable(s) and injection of water and/or solvent.
- Demonstrate the ability to have concurrent production of the associated gas zone with the production of the underlying bitumen.
- Understand lateral and vertical heat conduction and convection within the reservoir.
- Demonstrate commercial production capability and obtain an indication of ultimate recovery factor with this process.
- Gather data to enable accurate numerical simulation of the process and variations which will enable the optimization of this process on a commercial level.

The Pilot project was split into two stages, of which Stage 1 is documented in this report:

1. LEAD Pilot Stage 1: Cyclic Heating Stimulation (CHS) Test
    - Single horizontal well
    - Lower output heaters (~600W/m)
    - Cycle between heating reservoir for 3-6mths, then producing for ~1mth; repeat
    - Possibly inject water or solvent in later cycles

2. LEAD Pilot Stage 2: Full LEAD Pilot (future)
    - Horizontal ‘well pairs’ – heater/injector above, producer below
    - High output (~1000W/m) heaters required
    - Hot water/solvent injection to move heat into the reservoir and ‘drive’ the oil to the producer; continuous process

2.3 Chronology of Major Project Events

The chronology of major project events is provided in Table 2-1.

Table 2-1: Chronology of Major Project Events

Date	Event
Mar 25, 2014	Conducted Injection Test on 13-34-94-7W5 Vertical Well
Apr 3, 2014	Formation Damage Testing completed at Weatherford Labs
Jun 2, 2014	Obtained AER EPEA Approval No. 299681-00-00
Jul 11, 2014	Report on 4-34 Hz Wellbore Suitability for Thermal Project by Noetic Engineering
Jul 24, 2014	Obtained AER Experimental Scheme Approval No. 12283
Sep 24, 2014	Request for EPEA Authorization for LEAD Pilot Stage 1 submitted to AER
Sep 29, 2014	EPEA 'No Objection Letter' for LEAD Pilot Stage 1 received from AER
Nov 4, 2014	Conducted 4-34-94-7W5 Hz Well Cleanout & Gyro Log
Nov 12, 2014	Submitted Groundwater Monitoring Program Proposal to AER
Nov 13, 2014	Experimental Scheme Amendment Submitted for LEAD Pilot Stage 1
Feb 2, 2015	Groundwater Monitoring Program approved by the AER
Feb 12, 2015	Conducted Cement Bond Log on 4-34-94-7W5 for Directive 51 injector well application
Feb 24, 2015	Rig released PEOC Panny 12-34-94-7W5 observation well
Mar 3, 2015	Rig released PEOC Panny 6-34-94-7W5 observation well
May 6, 2015	Completed fuel gas pipeline from 8-33-94-7W5 to Pilot site 13-34-94-7W5
Jul 17, 2015	Installed downhole electrical heater and instrumentation in 4-34-94-7W5
Aug 5, 2015	Directive 51 Class IV Injection Well approval received for 4-34-94-7W5
Oct 13, 2015	Construction & commissioning completed on the Pilot facility at 13-34-94-7W5
Oct 15, 2015	Operations start-up including 'first heat' from the downhole electrical heaters
Feb 25, 2016	Pump installed
Mar 02, 2016	Pump started at 230 bbl/d
Sep 21, 2016	Directive 51 Class III & IV Injection Well approval received for 4-34-94-7W5
April 29, 2016	Start of Cycle 2 heating
Jun 21, 2016	Start of Cycle 2 production
Oct 13, 2016	End of Cycle 2 production, Start of Cycle 3 solvent injection
Oct 26, 2016	Start of Cycle 3 production
Nov 29, 2016	Toluene clean out, start of Cycle 4 heating, soak @ 120 deg C
Dec 05, 2016	Start of Cycle 4 production with heater @ 240 KW
Jan 06, 2017	Heater power @ 125 KW
May 02, 2017	Heater off
May 05, 2017	Well shut-in
May 31, 2017	End of project

2.4 Resource Update

McDaniel & Associates conducted an independent resource assessment as of December 31, 2011 and assigned Discovered Bitumen Initially-In-Place and Contingent Resources (Table 2-2). The basis for the Contingent Resources was Cyclic Steam Stimulation recovery, with assigned recovery factors ranging between 10 – 25%. Perpetual expected LEAD to achieve higher recovery factors than CSS, possibly equivalent to recovery factors seen in SAGD wells.

Table 2-2: Perpetual Panny Discovered Bitumen Initially-In-Place

Category / Level of Certainty	DBIIP (MMbbl)	Assigned Recovery Factor	Contingent Resource (MMbbl)
Low Estimate	509.2	10.0%	50.9
Best Estimate	**755.0**	**17.5%**	**132.1**
High Estimate	983.0	25.0%	245.8

The LEAD Pilot was designed to allow for economic oil recovery from reservoirs below a depleted gas cap. The low pressure and low energy design would allow for the recovery of oil without material influences from the gas cap. Later phases of the pilot were designed to include water and/or solvent injection to add energy to the reservoir to further increase recoveries. The initial modeling suggested materially better recovery factors would be possible over the 2011 contingent resource assessment which assumed CSS recovery factors of 17.5% Table 2-2.

The LEAD Pilot provided significant technical data with which to evaluate the reservoir (with the results of that evaluation presented herein). However, the discontinuous oil production resulting from premature heater failure and the corresponding production and decline data acquired is insufficient to directly predict a technical recovery factor at this time. Further, the failed heater prevented the last planned cycle which included water injection. Nonetheless, simulation work based on the history matched reservoir model from the Pilot suggests technical recovery factors near the high end of the 2011 estimates. This is because the low-pressure electric heating and production process can continue following breakthrough to the gas cap. Recovery beyond 25% is believed attainable with appropriate well spacing.

Breakthrough to the gas cap did occur during the LEAD Pilot, and demonstrated that continuous oil production under predominantly gravity drive remains feasible following pressure equalization of the bitumen layer with the depleted gas cap. This fulfilled one of the objectives of the Pilot study.

The combination of breakthrough to the gas cap and a limited dataset as a result of the failed heater does not provide adequate information to support an increase in recovery factor despite indications of such on the reservoir simulation. The short life of the heater also adds incremental costs to any economic models as they have to be replaced with an increased frequency. The combination of these factors suggest that a reassessment of the contingent resource is not warranted at this time.

3 Well Information

3.1 Well Layout

The well layout for Stage 1 CHS Test can be found in Figure 3-1.

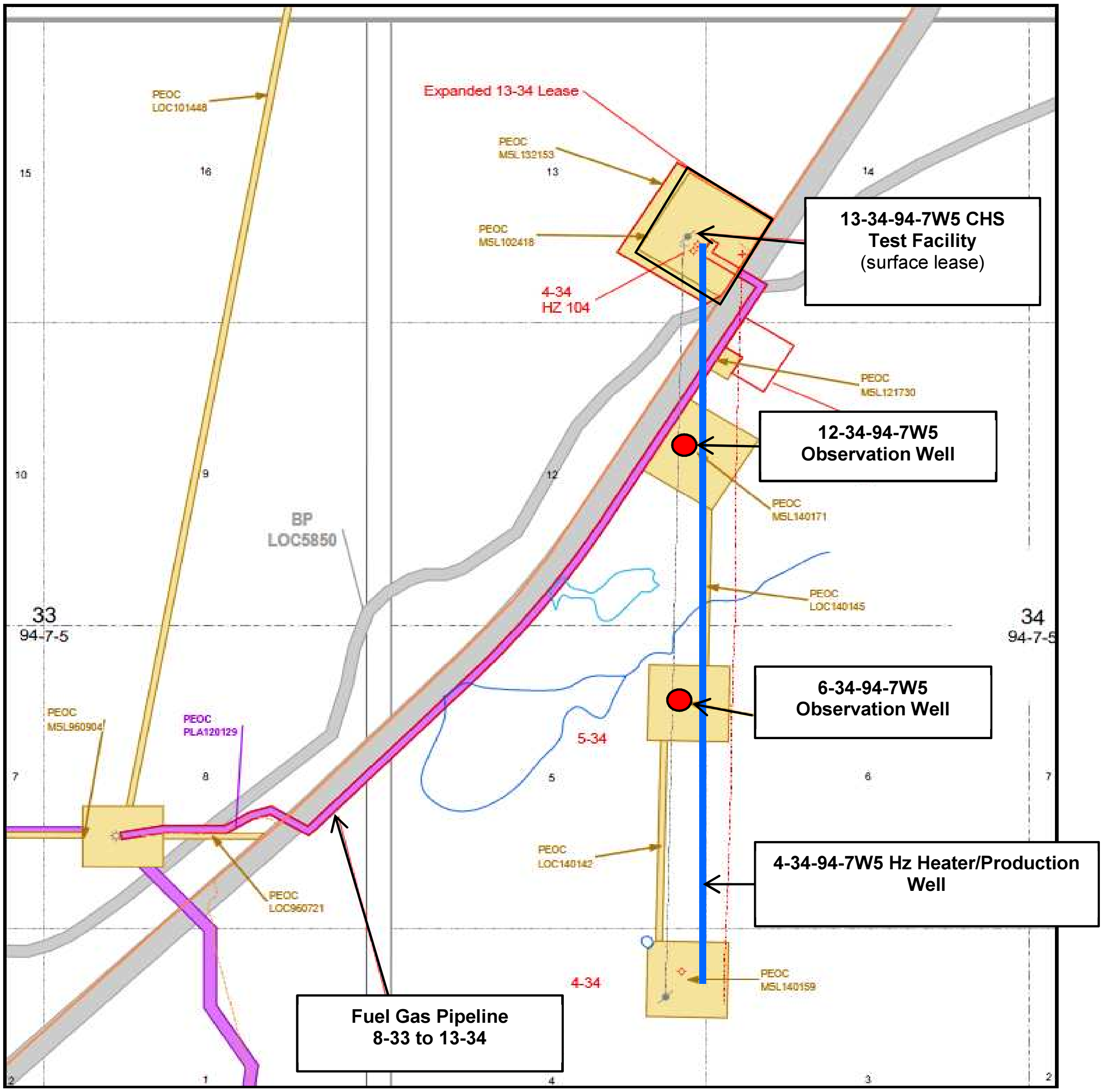

Figure 3-1: LEAD Pilot Stage 1 CHS Test Layout

3.2 Drilling, Completion, and Workover Operations

3.2.1 Drilling

In 2015 two observation wells were drilled and cased. Both wells had the same well design, as depicted in Figure 3-2. Each observation well has 7 pressure and 19 temperature sensors:

- 12 thermocouples (6 duplex MI cables x 2 TC's per cable)
- 7 pressure + temperature combo sensors (1 MI cable each)
- All sensors are clamped to the outside of the casing and cemented in-place
- No perforations in the casing

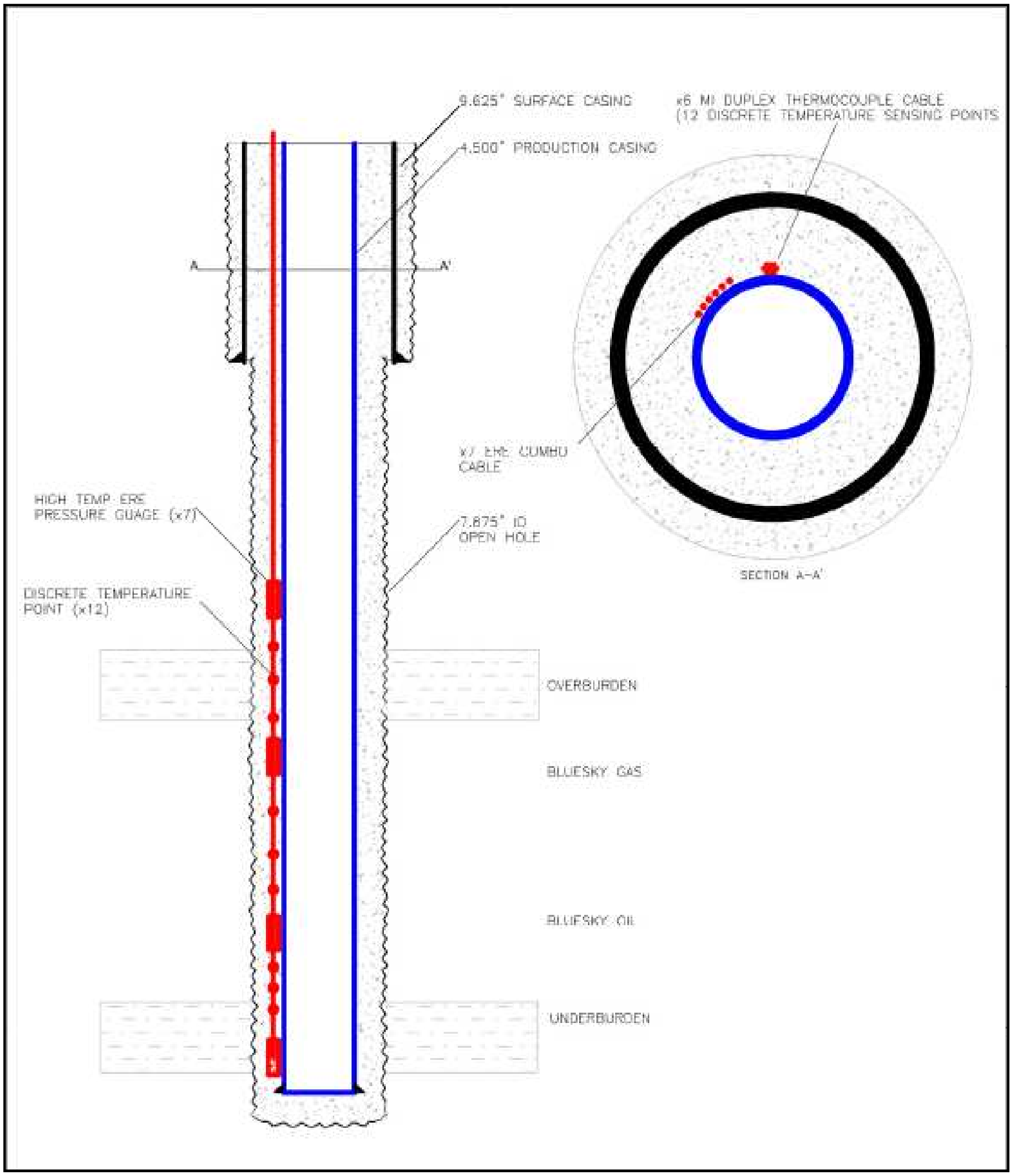

Figure 3-2: Observation Well Design

Details for each well include:

- PEOC Panny 12-34-94-7 (102/12-34-094-07W5/0)
    - Spudded Feb 18, 2015; rig released Feb 24, 2015
    - Drilled surface, ran 219.1mm (9 5/8") J-55 ST&C surface casing set at 118m
    - Drilled out with directional tools, KOP at 213m, build hole angle to 7° to core point at 301.4m
    - Cored from 301.4m to 342m with 99.6% core recovery, ran ranging check shots to the 4-34 horizontal well between cores
        - Cut core #1 and then RIH with survey tools to take ranging shot
        - Cut core #2 and then RIH with survey tools to take ranging shot
        - Cut cores #3-6, RIH with directional drilling BHA and Range to 4-34
    - Drilled to 348.5m (bit was 8.5m into the Paleozoic, 0.5m away from planned TD) when well lost mud circulation; losses quickly cured and circulation recovered
    - Open hole logged
    - Ran 114.3mm (4.5") L-80 SLHT casing with sensors, cemented with Thermal-40 cement with 4.0 m3 returns
    - Final ranging shows 3.58m separation to 4-34 horizontal well

- PEOC Panny 6-34-94-7 (100/06-34-094-07W5/0)
    - Originally licensed as 5-34-94-7W5
    - Spudded Feb 25, 2015; rig released Mar 3, 2015
    - Drilled surface hole and kicked-off directional at 100mMD; landed surface casing at 165mMD
    - Drilled out with directional tools and build hole angle to 9° by core point at 299.7m
    - Cored from 299.7m to 341.2m with 99.4% core recovery:
        - Cut core #1 and then RIH with survey tools to take ranging shot
        - Cut core #2 and then RIH with survey tools to take ranging shot
        - Cut cores #3-6, RIH with directional drilling BHA and Range to 4-34
    - Lost mud circulation in Paleozoic, cured losses
    - Open hole logged
    - Ran 114.3mm (4.5") L-80 SLHT casing with sensors, cemented with Thermal-40 cement
    - Cement briefly lost circulation, top filled cement ~50m
    - Ran cement bond long – good cement
    - TD crossed into LSD 6-34; well license amended
    - Final ranging shows 3.01m separation to 4-34 horizontal well

3.2.2 Well Workover Operations

February 25, 2016	Installed pump
April 28, 2016	Pulled pump for inspection
June 21, 2016	Re-installed pump after second cycle heating
October 13, 2016	Solvent injection
November 05, 2016	Pulled pump for inspection
November 29, 2016	Re-installed pump

The existing horizontal well PEOC HZ Panny 4-34-94-7 (100/04-34-094-07W5/0) was used as the heater/producer well for the Stage 1 CHS Test. This well was originally rig released March 19, 2011 as a cold production well. The wellbore has 9 5/8” intermediate casing, J-55 LT&C, and a 7” liner, J-55 LT&C.

A service rig installed the downhole heater and instrumentation on July 12-17, 2015. A completion schematic is provided in Figure 3-4.

- Clamped the electrical heaters and instrumentation to the 2 7/8” & 3 ½” L80 VAM Top tubing string using 300+ clamps, clamped (at minimum) every tubing mid-joint and collar (minimum 2 clamps per joint), centralized at every collar
- Landed the tubing string at 1202 mKB
- Installed rod pump

3.3 Well Operations

Commenced monitoring of reservoir pressures and temperatures in the two observation wells at 100/06-34-094-07W5 & 102/12-34-094-07W5 in March 2015.

Commenced surface casing pressure recording on October 15, 2015 at existing vertical well 100/13-34-094-07W5/0 to monitor far-field effects of the CHS Test in the Bluesky reservoir.

Commenced Cycle 1 heating cycle in the 100/04-34-094-07W5/0 horizontal on October 15, 2015 using the downhole electrical heaters. Commenced Cycle 1 production on March 02, 2016 at 36.5 m3 oil per day (230 bopd). Heaters remained on at low heat for flow assurance.

Commenced Cycle 2 production with heating on June 21, 2016. Heating was optimized within the intermediate casing temperature constraint.

Conducted Cycle 3 solvent injection in 100/04-34-094-07W5/0 in November 2016.

Commenced Cycle 4 production December 05, 2016. Cycle 4 production ended May 06, 2017.

3.3.1 13-34-94-7W5 Injection Test

Injection test was conducted on vertical well 100/13-34-094-07W5/0 between March 14-25, 2014, with downhole pressure recorders. The downhole recorders were removed from the wellbore on July 3-4, 2014.

While some minor pressure pumping equipment issues were encountered, this test was successful in recovering significant reservoir data including reservoir fracture gradient and current bitumen reservoir pressures.

3.3.2 4-34-94-7W5 Hz Cleanout & Gyro

Between October 29 and November 4, 2014 a wellbore cleanout and gyro log were conducted on the horizontal wellbore 100/04-34-094-07W5.

The objective of the cleanout was to prepare the wellbore for the installation of the downhole electrical heater tubing string by removing any heavy oil, sand or fines, or liner burrs, and to ensure a tubing string could successfully be landed to TD.

The objective of the gyro survey was to enable an accurate directional drilling planning for the 2 observation wells that were to be landed 3-4m away from the 4-34 Hz wellbore.

This workover was executed with the following steps and results:

- Pulled existing rod and tubing string including PC pump out of hole.
- Ran in hole with open ended tubing string to TD (no issues running to TD) and circulated out wellbore (heavy oil and some minor drilling mud returns). Pulled out of hole.
- Ran tapered mill with mud motor to TD (no tight spots encountered so no milling required). Pulled out of hole.
- Conducted gyro log using tractor.

The cleanout was successful in preparing the wellbore and providing assurance there would be no issues landing a tubing string complete with electrical heaters and instrumentation to TD, even at the relatively shallow true vertical depth of the well.

The gyro log was significant in identifying that the wellbore was consistently 2.0° off of the original MWD drilling survey, which equated to the toe of the well actually being 36m east of where it was believed to be. This was an important finding in order to properly re-plan the observation wells' drilling plans to assure landing them 3-4m away from 100/04-34. The source of this directional variance may be a local magnetic anomaly. An in-field magnetic survey was not conducted prior to drilling the 4-34 Hz well originally, and may have identified any anomaly. Future directional or horizontal drilling plans in this area should consider this type of local magnetic survey.

A summary of the difference between the original MWD direction survey and the new gyro log is shown in Figure 3-3.

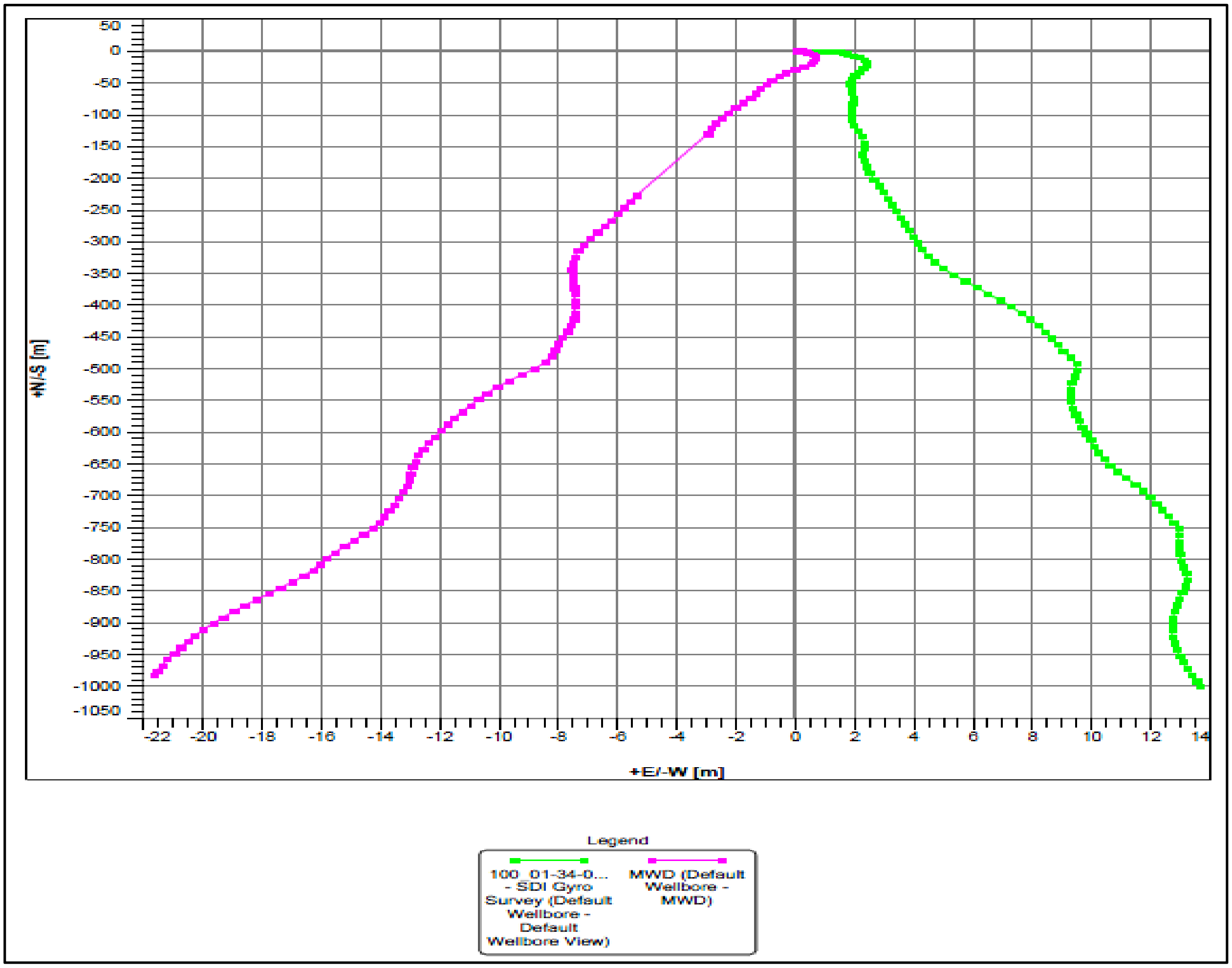

Figure 3-3: 4-34 Hz Gyro vs MWD Survey Relative Comparison

3.4 Well List and Status

The current well list and status can be found in Table 3-1.

Table 3-1: Current Well List and Status

Well Name	UWI	Purpose	2017 Status
PEOC HZ Panny 4-34-94-7	100/04-34-094-07W5/0	Heating and production well	Operational
PEOC Panny 6-34-94-7	100/06-34-094-07W5/0	Observation well	Operational
PEOC Panny 12-34-94-7	102/12-34-094-07W5/0	Observation well	Operational
PEOC Panny 13-34-94-7	100/13-34-094-07W5/0	Far-field observation well	Operational

3.5 Wellbore Schematics

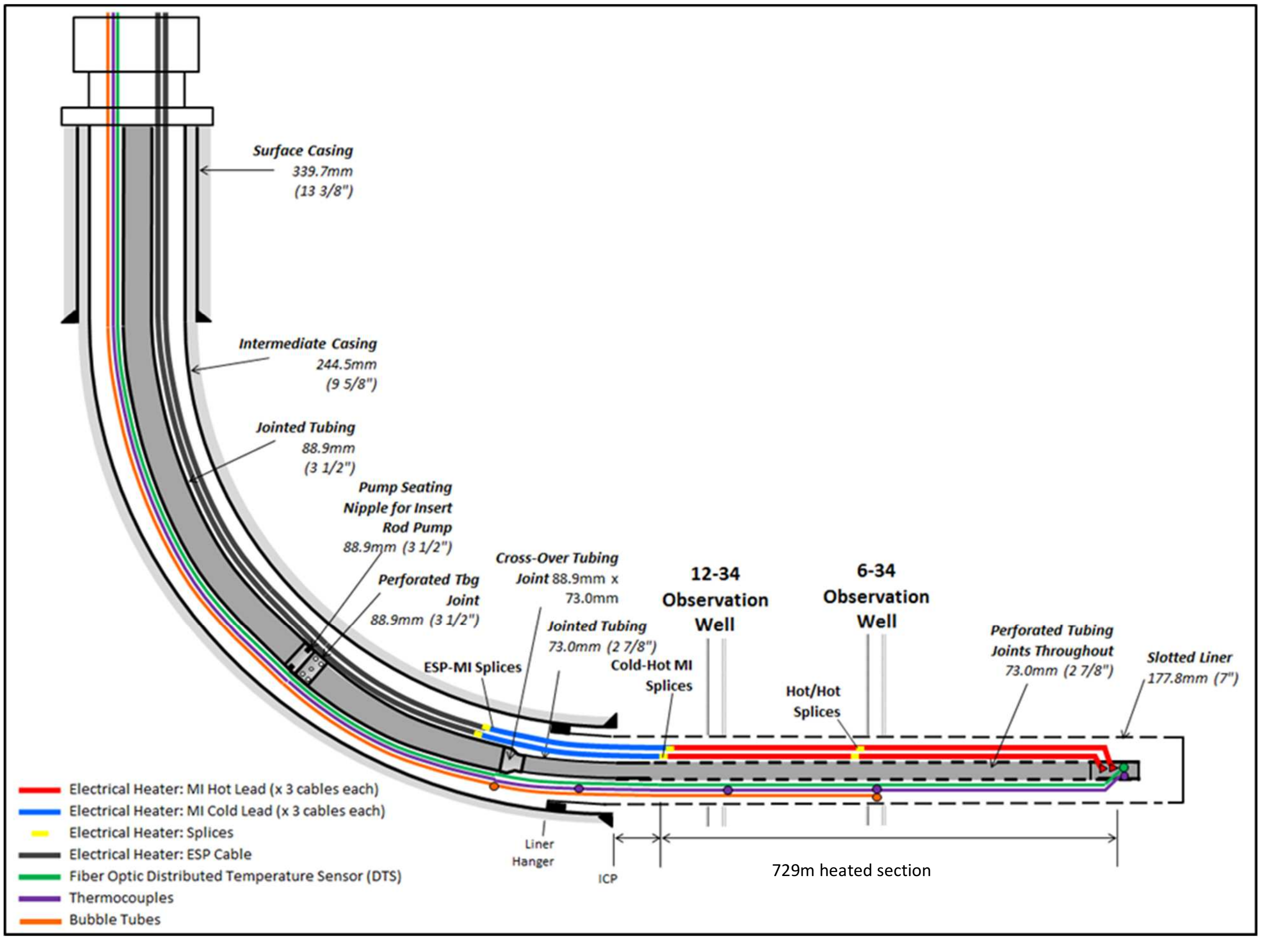

Figure 3-4: 4-34-94-7W5 Hz Downhole Completion Schematic

The instrumentation installed in the 4-34-94-7W5 horizontal well included:

- 2 bubble tubes using N_2 gas for pressure measurement
- 1 fiber optic Distributed Temperature Sensing (DTS) string with 1m resolution from toe to wellhead
- 4 thermocouples (redundancy for DTS)

4 Production Performance and Data

4.1 Production, Injection, and Heating

Heating commenced in 2015. Production while heating continued into 2017.
The heating and production summary can be found in Table 4-1.

Table 4-1: Reservoir Heating and Production Summary

Month	Energy Delivered to Reservoir* (GJ)	Bitumen Production (m^3)	Water Production (m^3)	Gas Production (10^3m^3)	Solvent Injection (m^3)	Comments
Oct-2015	669	0	0			
Nov-2015	586	0	0			
Dec-2015	976	0	0			
Jan-2016	927	0	0			
Feb-2016	727	0	0			
Mar-2016	392	233.1	10.9	4.3	0	
April-2016	260	21.8	0	1.4	0	
May-2016	885	0	0			
Jun-2016	742	202.2	17	1.5	0	
Jul-2016	701	261	16.1	5.5		
Aug-2016	692	185.1	5.1	3.6		
Sep-2016	722	166	14	3.5		
Oct-2016	588	20	46.8	5.3	50	C5+
Nov-2016	517	20.3	0	1.5	25	Toluene
Dec-2016	579	202.7	11.0	5		
Jan-2017	369	117.7	6.8	4.3		
Feb-2017	297	80.73	4.0	3.8		
Mar-2017	308	71.5	4.1	3.7		
April-2017	321	63.7	5.0	3.1		
May-2017	13	4.2	0.3	0.6		

** The energy delivered to the reservoir is a calculated value of energy output from the heater hot lead sections which nets-off energy consumed by the ESP cable and heater cold lead sections*

The electrical heaters were primarily operated on a temperature-controlled set-point. The maximum operating temperature of the fiber optic DTS system is 300°C, so the heaters were operated at no higher than 270°C to avoid damaging the DTS.

Initial reservoir heating was from October 10, 2015 to February 21, 2016. The heater was then turned off to allow cool down before bleed off. Pumping difficulties were encountered with higher oil viscosities at lower temperatures. First cycle production was therefore completed with low heat from the heater for flow assurance. Subsequent production cycles were conducted with increased heating input while producing for both flow assurance and continued reservoir heating, within the wellbore / DTS temperature constraints.

4.2 Composition of Produced / Injected Fluids

Cold primary production from 100/04-34-094-07W5 in 2011 produced oil with API gravity of 11.49, per Figure 4-1, below. Oil from adjacent cores ranged with API gravities of 11.69 to 10.36.

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OIL ANALYSIS

Container Identification
PB1

Operator Name	Laboratory Number
PERPETUAL ENERGY INC	110495582A

Unique Well Identifier	Well Name
100/04-34-094-07W5/00	PEOC Hz PANNY 4-34-94-7

Field or Area	Pool or Zone	Sampler's Company
PANNY	NOT AVAILABLE	SAME

Well License	Elevation	Test Type	Test No.	Name of Sampler
0427864	KB m 464.80 GRD m 461.00			

Test Interval or Perfs mKB	Sampling Point
	WELLHEAD

	Separator	Reservoir	Source	Sampled	Received
Pressure (kPa)					
Temperature					

Date Sampled	Date Received	Date Analyzed	Date Reported	Entered By	Certified By
Apr 29, 2011	May 25, 2011	May 26, 2011	May 26, 2011		

Other Information

* Results relate only to the items tested

Note: Sampling Point, Unique Well Identifier and/or Pool or Zone information was unavailable at time of reporting. This information is integral to AGAT's WebFLUIDs, a comparison, history and trending analysis system.

Sample Properties

Colour of Clean Oil	Colour Number ASTM D-1500
Dk. Brown	D8 A.S.T.M.

B.S.& W. (Volume Fraction)

Free Water
72.20 vol %

Density - After Cleaning

API Gravity @ 15°C	Relative	Absolute (kg/m³)
11.49	0.9896	988.7

Total Sulphur Mass Fraction	Pour Point (°C) (A.S.T.M. D-97)
0.03541	+3

Viscosity

Temp °C	Absolute (mPa*s)	Kinematic (mm²/s)
25	11005.60	11194.83
38	3143.16	3220.71
50	1130.22	1165.89

Distillation

Absolute Barometric Pressure (kPa)
89.9

Room Temp (°C)
23.0

Characterization Factor
11.3

Other Comments:

BS&W performed on oil portion only.
BS&W Volume Fraction not performed due to insufficient amount of oil sample.
D-86 Distillation not performed on heavy oils as per ASTM standard.

Calgary AB, Ph: (403) 299-2000. Edmonton AB, Ph: (780) 469-0106. Grand Prairie AB, Ph: (780) 539-6500. Red Deer AB, Ph: (403) 346-6645. Fort St. John BC, Ph: (250) 785-5500. Prince George BC, Ph: (250) 563-6011. Terrace BC, Ph: (250) 615-9288. Mississauga ON, Ph: (905) 501-9998.

Figure 4-1: Oil Analysis May 29, 2011 – Cold Primary Production

Later samples collected from 100/04-34-094-07W5 in 2014 showed consistent oil properties (density, viscosity, sulphur content, pour point) per Figure 4-2, below.

AGAT Laboratories

OIL ANALYSIS

Container Identification	PB3A
Sample Point Code	
Meter Code	
AGAT WDMS Number	
Previous Number	
Laboratory Number	14O901932A
Operator Name	PERPETUAL ENERGY INC.
Sampling Point	WELLHEAD
Unique Well Identifier	100/04-34-094-07W5/00
Well Name	PEOC Hz PANNY 4-34-94-7
Well License	0427864
Well Status	
Well Fluid Status	
LSD	
Field or Area	PANNY
Pool or Zone	BLUESKY C
Sampler's Company	PERPETUAL ENERGY INC.
Name of Sampler	JOHN HURST
Test Interval (mKB) From / To	
Test Type	
Test No.	
Elevation (m) KB	464.80
Elevation (m) GRD	461.00
Pressure (kPa) Source / Received	
Temperature (°C) Source / Received	
Date Sampled	Oct 05, 2014
Date Received	Oct 14, 2014
Date Analyzed	Oct 21, 2014
Date Reported	Oct 24, 2014
Location - Approved By - Title	Calgary - Valentina Strelnikova - Supervisor
Other Information	

PROPERTIES

Color ASTM D1500

Colour Number	Colour of Clean Oil
D8	Dark Brown

Density of Clean Oil @ 15°C ASTM D5002/ASTM D4052

Relative	API (°)	Absolute (kg/m³)
0.9899	11.44	989.0

B.S. & W. ASTM D4007 (Vol %)

Water	Sediment	Total
6.0	0.4	6.4

Free Water	Free Sediment
ND	ND

Total Sulphur (mass %) ASTM D4294	Pour Point (°C) ASTM D97/ASTM D5853
3.516	+6

Other Comments:

TAN=2.13 mg KOH/g
D-86 Distillation not performed on heavy oils as per ASTM standard
TAG Closed Cup Flash Point (ASTM D56) (After cleaning) = 83.5 °C

DISTILLATION ASTM D86

Initial Boiling Point (°C)	
Naphtha (200 °C) (Vol %)	
Final Boiling Point (°C)	
Kerosene (275 °C) (Vol %)	
Characterization Factor	11.3
Light Gas Oil (350 °C) (Vol %)	
Distillation Loss (Vol %)	
Recovered (Vol %)	
Residue (Vol %)	
Room Temp (°C)	23.0
Absolute Barometric Pressure (kPa)	88.2

VISCOSITY ASTM D445 / ASTM D7042

Temperature (°C)	Absolute (mPa*s)	Kinematic (mm²/s)
25.0	11583.92	11779.00
38.0	3606.61	3694.30
50.0	1297.43	1337.90

Results relate only to items tested. Analysis (except free water) were performed on the oil after cleaning. Distillation temperatures have been corrected to 101.3 kPa (abs).

Figure 4-2: Oil Analysis Oct 05, 2014 – Cold Primary Production

AGAT Laboratories

OIL ANALYSIS

Container Identification	Sample Point Code	Meter Code	AGAT WDMS Number	Previous Number	Laboratory Number
PB1A				16O074330A	16O120494A

Operator Name	Sampling Point	Unique Well Identifier
PERPETUAL ENERGY INC.	WELLHEAD	100/04-34-094-07W5/00

Well Name	Well License	Well Status	Well Fluid Status	LSD
PEOC Hz PANNY 4-34-94-7	0427864			

Field or Area	Pool or Zone	Sampler's Company	Name of Sampler
PANNY	BLUESKY C	PERPETUAL ENERGY INC.	PH

Test Interval (mKB) From	Test Interval (mKB) To	Test Type	Test No.	Elevation (m) KB	Elevation (m) GRD	Pressure (kPa) Source	Pressure (kPa) Received	Temperature (°C) Source	Temperature (°C) Received
				464.60	461.00	67		26	

Date Sampled	Date Received	Date Analyzed	Date Reported	Location - Approved By - Title
Mar 11, 2016	Jul 28, 2016	Aug 05, 2016	Aug 05, 2016	Calgary - Valentina Strelnikova - Supervisor

Other Information

PROPERTIES

Color ASTM D1500

Colour Number	Colour of Clean Oil
D8	Dark Brown

Density of Clean Oil @ 15°C ASTM D5002 / ASTM D4052

Relative	API (°)	Absolute (kg/m³)
0.9830	12.45	982.1

B.S. & W. ASTM D4007 (Vol %)

Water	Sediment	Total
0.2	TRACE	0.2

Free Water	Free Sediment
11.70 vol %	ND

3.736
Total Sulphur (mass %) ASTM D4294

Other Comments:

BS&W performed on oil portion only
SARA TEST (ASTM D2007):
Asphaltene (Pentane Insoluble) =11.41 % Wt
Saturates =28.17 % Wt
Resins (polars) =9.27 % Wt
Aromatics =51.15 % Wt

DISTILLATION ASTM D86

Room Temp (°C)	Absolute Barometric Pressure (kPa)
23.0	89.2

11.3
Characterization Factor

VISCOSITY ASTM D445 / ASTM D7042

Temperature (°C)	Absolute (mPa*s)	Kinematic (mm²/s)
25.0	5850.89	5991.9
38.0	1835.27	1893.5
50.0	691.12	717.9

Results relate only to items tested. Analysis (except free water) were performed on the oil after cleaning. Distillation temperatures have been corrected to 101.3 kPa (abs).

View or download your data online at webfluids.agatlabs.com

Figure 4-3: Analysis of Oil Produced after Heat Injection - Mar 11, 2016

Analysis of oil produced from 100/04-34-094-07W5 following initial reservoir heating is presented in Figure 4-3, above. The Saturates, Aromatics, Resins and Asphaltene (SARA) analysis indicated relatively high asphaltene content (11.41% wt.). This is a concern with thermal or solvent processes due to the risk of asphaltene precipitation potentially reducing permeability of plugging the well.

The post-heating oil sample had higher API, lower viscosity and lower oil density suggesting fewer heavy ends were present in the oil sample compared to earlier cold-produced oil.

HYDROCARBON LIQUID ANALYSIS

Operator: Perpetual Energy Inc. Page: 8
Well: POC Panny 4-34-94-7 File: 52137-2016-2924-12-V0002979
Sample Point: Wellhead Tubing Date: 2016 11 10

Analysis of C_{30+} Fraction

Boiling Point: Range (° C)	Component	Carbon Number	Mole Fraction	Mass Fraction	Liq. Vol. Fraction
-161.7	Methane	C_1	0.0018	0.0001	0.0003
- 88.9	Ethane	C_2	Trace	Trace	Trace
- 42.2	Propane	C_3	Trace	Trace	Trace
- 11.7	Iso Butane	C_4	Trace	Trace	Trace
- 0.6	Normal Butane	C_4	0.0064	0.0013	0.0019
27.8	Iso Pentane	C_5	0.0935	0.0234	0.0321
36.1	Normal Pentane	C_5	0.1075	0.0269	0.0365
36.1- 68.9	Hexanes	C_6	0.0776	0.0232	0.0299
68.9- 98.3	Heptanes	C_7	0.0253	0.0088	0.0109
98.3-125.6	Octanes	C_8	0.0169	0.0067	0.0081
125.6-150.6	Nonanes	C_9	0.0072	0.0032	0.0038
150.6-173.9	Decanes	C_{10}	0.0024	0.0012	0.0014
173.9-196.1	Undecanes	C_{11}	0.0073	0.0037	0.0040
196.1-215.0	Dodecanes	C_{12}	0.0113	0.0063	0.0068
215.0-235.0	Tridecanes	C_{13}	0.0155	0.0094	0.0099
235.0-252.2	Tetradecanes	C_{14}	0.0187	0.0123	0.0128
252.2-270.6	Pentadecanes	C_{15}	0.0211	0.0151	0.0155
270.6-287.8	Hexadecanes	C_{16}	0.0218	0.0168	0.0171
287.8-302.8	Heptadecanes	C_{17}	0.0225	0.0185	0.0187
302.8-317.2	Octadecanes	C_{18}	0.0233	0.0203	0.0204
317.2-330.0	Nonadecanes	C_{19}	0.0228	0.0208	0.0208
330.0-344.4	Eicosanes	C_{20}	0.0227	0.0217	0.0215
344.4-357.2	Heneicosanes	C_{21}	0.0212	0.0214	0.0211
357.2-369.4	Docosanes	C_{22}	0.0189	0.0200	0.0196
369.4-380.0	Tricosanes	C_{23}	0.0165	0.0182	0.0178
380.0-391.1	Tetracosanes	C_{24}	0.0154	0.0177	0.0172
391.1-401.7	Pentacosanes	C_{25}	0.0150	0.0179	0.0174
401.7-412.2	Hexacosanes	C_{26}	0.0132	0.0165	0.0158
412.2-422.2	Heptacosanes	C_{27}	0.0129	0.0168	0.0160
422.2-431.7	Octacosanes	C_{28}	0.0117	0.0158	0.0150
431.7-441.1	Nonacosanes	C_{29}	0.0113	0.0158	0.0150
441.1 PLUS	Triacontanes Plus	C_{30+}	0.2803	0.5828	0.5539
80.0	Benzene	C_6H_6	0.0055	0.0015	0.0014
110.6	Toluene	C_7H_8	0.0059	0.0019	0.0019
136.1-138.9	Ethylbenzene, p + m-Xylene	C_8H_{10}	0.0035	0.0013	0.0013
144.4	o-Xylene	C_8H_{10}	0.0011	0.0004	0.0004
168.9	1,2,4 Trimethylbenzene	C_9H_{12}	0.0002	0.0001	0.0001
48.9	Cyclopentane	C_5H_{10}	0.0090	0.0022	0.0025
72.2	Methylcyclopentane	C_6H_{12}	0.0144	0.0042	0.0048
81.1	Cyclohexane	C_6H_{12}	0.0099	0.0029	0.0032
101.1	Methylcyclohexane	C_7H_{14}	0.0085	0.0029	0.0032
	TOTAL		1.0000	1.0000	1.0000

Molecular mass of stabilized liquid by freeze point depletion = 301.5 g/mol

Figure 4-4: Oil Analysis of Produced Oil after Heat Injection and Post Solvent Injection

Figure 4-4 presents the analysis of oil produced following heating and injection of solvent. The high molar fraction of C5 and C6 (~28%) is reflective of the solvent present in the produced oil.

							Viscosity				
Date	Density	API	Saturates	Asphatene	Resin	Aromatics	25	38	50	BSW	
	Kg/m3		% wt	% wt	% wt	% wt	cP	cP	cP	% Water	% Sed
April 29, 2011	988.0	11.49					11,005.6	3,143.2	1,130.0		
October 5, 2014	989.0	11.44					11,583.9	3,606.6	1,297.4	6.0	0.4
October 7, 2014	995.1	10.57	20.17	9.90	12.32	57.61	17,807.7	6,911.1	2,237.0	36.0	0.4
March 3, 2016	978.7	12.96					4,296.3	1,370.6	551.4	12.4	0.0
March 11, 2016	982.1	12.45	28.17	11.41	9.27	51.15	5,850.9	1,835.3	691.1	0.2	0.0
March 29, 2016	984.1	12.16					7,263.4	2,211.9	843.3	0.2	0.0
April 14, 2016	984.8	12.06		11.45			7,820.5	2,228.9	795.3	0.2	0.0
June 24, 2016	987.0	11.73		10.70			7,503.6	1,974.6	756.6	1.0	0.0
July 10, 2016	988.9	11.47		11.57			8,588.0	2,251.2	825.9	4.0	0.0
July 27, 2016	989.3	11.4		10.72			8,775.0	2,599.4	937.6	9.0	0.0
August 12, 2016	989.1	11.43		10.63			9,013.8	2,621.6	950.6	1.0	0.0
October 28, 2016	698.9	70.78					0.4			0.0	0.0
November 1, 2016	948.6	17.54	26	9.02	11.85	53.13	331.6	149.5	79.6	2.8	0.0
December 11, 2016	962.7	15.36					530.8	219.6	112.1	12.0	0.0
May 2, 2017	986.1	11.87	25.59	9.91	19.3	45.2	8,181.7	2,422.2	888.3	8.8	0.0

Table 4-2: Oil Sample Analyses through Time

Table 4-2 summarizes the results of oil sample analyses through time. API is observed to increase slightly with early heating, then return back to pre-heat injection values before spiking with the injection of solvent (ref. Oct 28/16 sample), and then again returning to initial values.

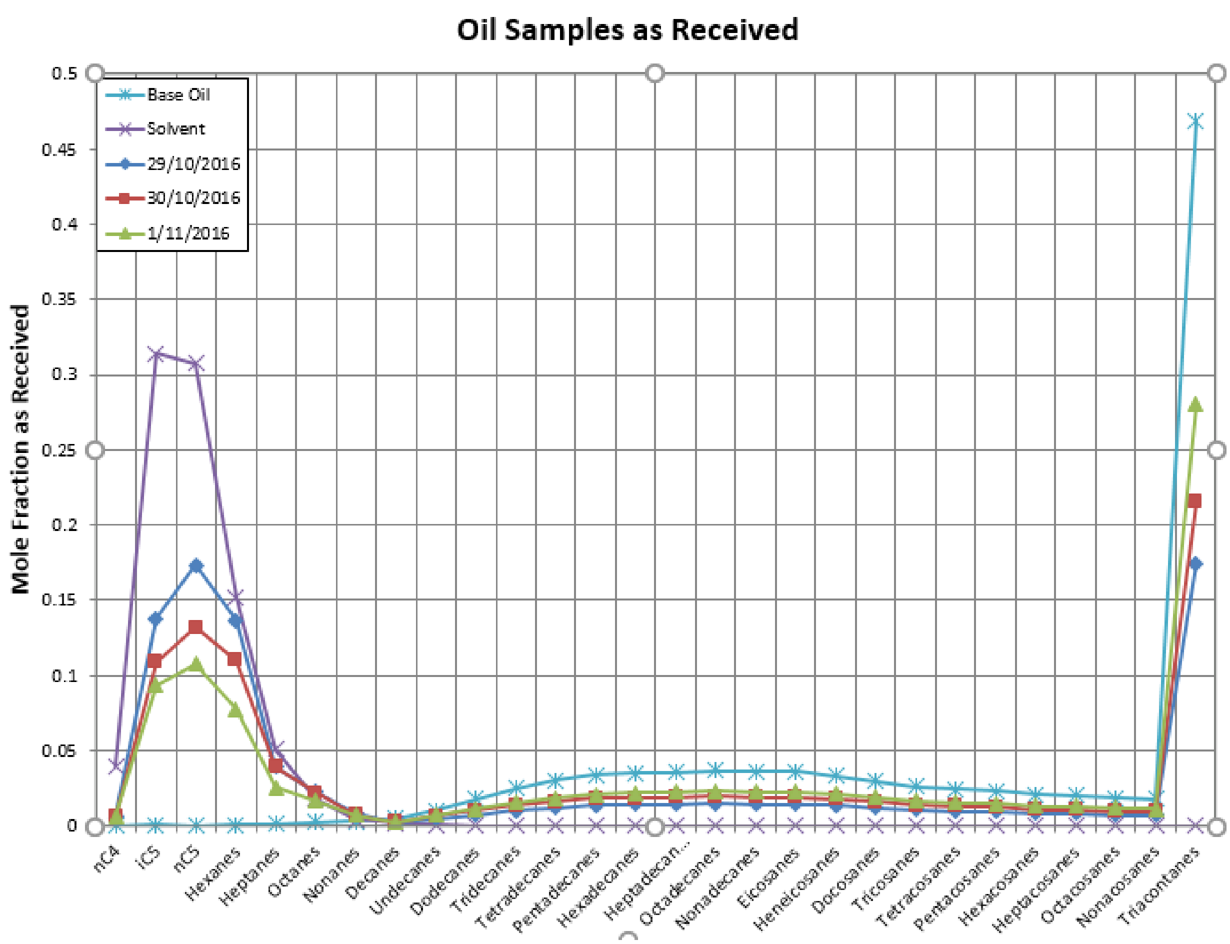


Figure 4-5: Oil Sample Analyses and Injected Solvent (Solvent Injection Oct 13, 2016)

Figure 4-5 shows comparative oil sample components for initial cold oil production (Base Oil), injected solvent, and post solvent oil production immediately prior to well deliverability loss. C5 and C6 from the solvent are clearly present in the post solvent oil samples.

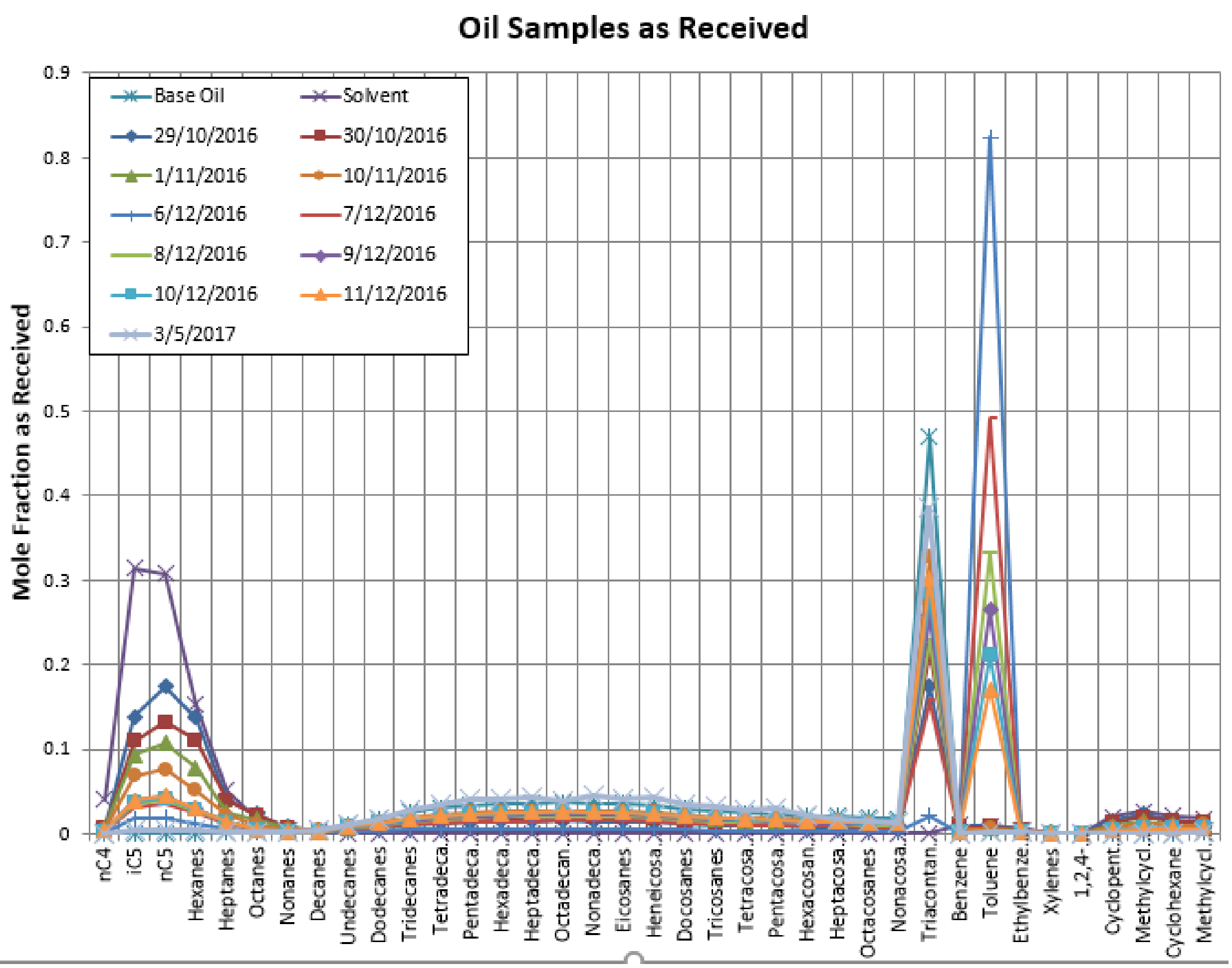


Figure 4-6: Oil Sample analyses Post Solvent Injection / Post Toluene Cleanup (Solvent Injection Oct 13, 2016) / (Toluene Injection Nov 29, 2016)

Figure 4-6 shows comparative oil sample components for initial cold oil production (Base Oil), injected solvent, post solvent oil production immediately prior to well deliverability loss, and post toluene clean-up. C5 and C6 from the solvent are seen to continue to diminish with ongoing production. Toluene spiked at the time of clean-up, and then also diminished through time. (Toluene was placed in the wellbore to dissolve the asphaltene that precipitated following the addition of solvent, as discussed elsewhere herein.)

Produced oil with solvent and toluene content has significantly lower viscosity, as per Table 4-2. This supports the expectation that solvent reduces oil viscosity.

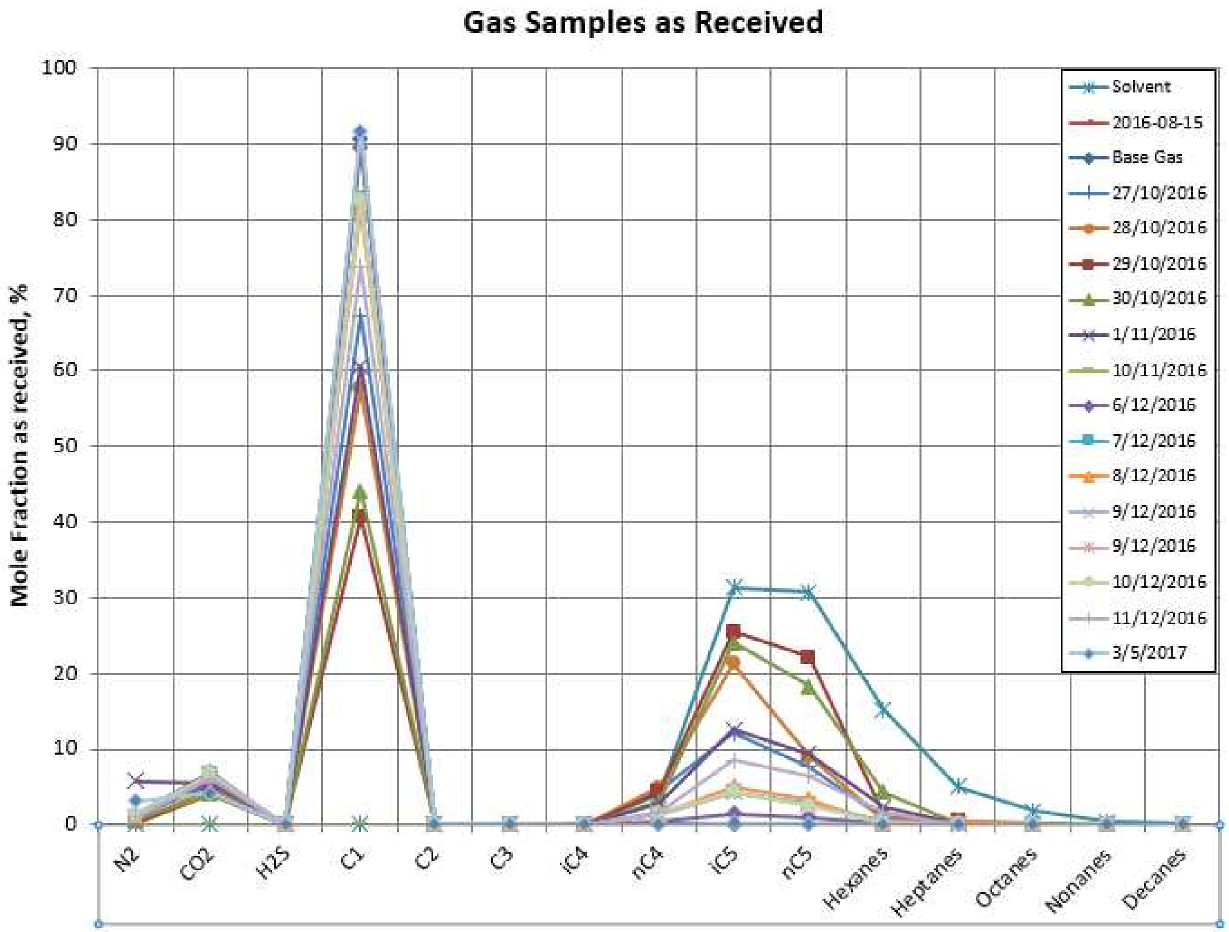


Figure 4-7: Produced Gas Sample Analyses

Figure 4-7 presents produced gas sample analyses prior to heat injection, during heat injection, and post solvent injection. C5 and C6 from the solvent are clearly present in the post solvent gas samples, as they were in the post solvent oil samples.

4.3 Comparison of Predicted versus Actual Well / Pilot Performance

A key objective of the LEAD Pilot was to evaluate the ability to concurrently produce both natural gas and crude bitumen from an oil sands deposit with a gas cap, where production of the natural gas might normally be subject to constraint under an order from the Alberta Energy Regulator to conserve the gas drive energy for the crude bitumen. The Pilot successfully produced bitumen concurrently with gas cap gas production, with pump rate modulated as required to control Gas Oil Ratio.

In order to measure increases in reservoir temperature with heating in a reasonable period of time, it was necessary to place vertical observation wells very near to the 100/04-34-94-07W5 horizontal. Using ranging technology, 100/06-34-094-07W5 was located ~3 m from the horizontal, and 102/12-34-094-07W5 was located ~3.5 m from the horizontal. As a result, temperature increases were recorded at the two observation wells within days of initiating heating of the horizontal.

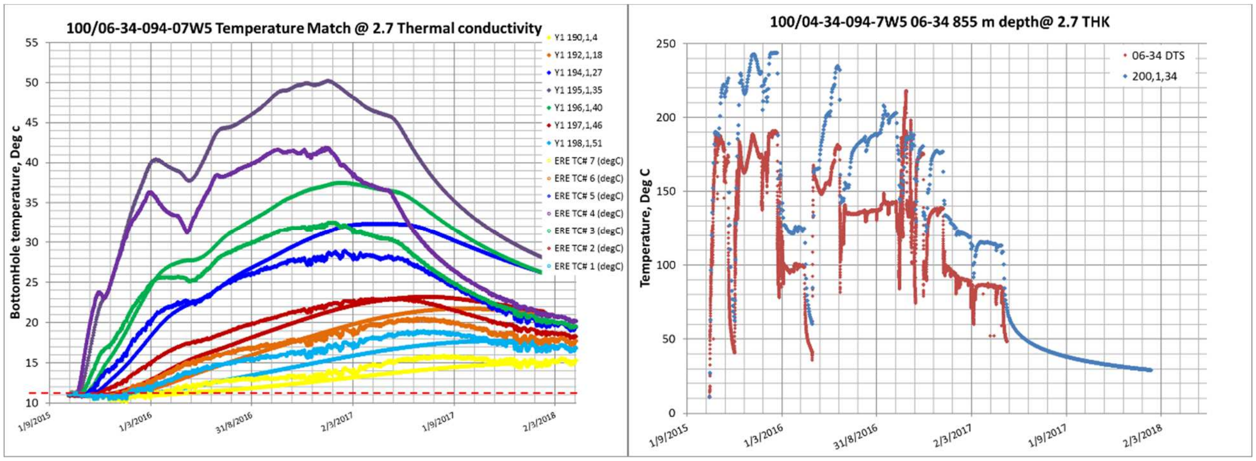


Figure 4-8: Temperature Modelling Match with 2.70E05 J/(m*day*C) Rock Thermal Conductivity

Estimated Rock Thermal Conductivity (RTC) prior to the Pilot was 2.70E+05 J/(m*day*C). Per Figure 4-8, using this parameter the simulated temperatures at the observation wells through time were higher than observed, suggesting higher heat retentions near the wellbore in the model.

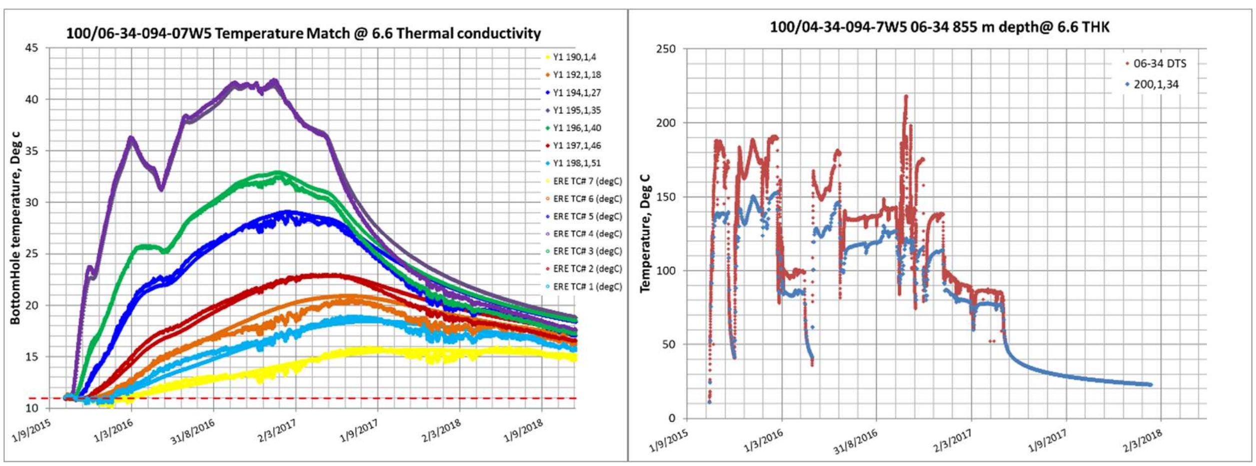


Figure 4-9: Temperature Modelling Match with 6.60E05 J/(m*day*C) Rock Thermal Conductivity

Per Figure 4-9, increasing the estimated RTC to 6.60E+05 J/(m*day*C) resulted in a very good match with all temperature gauges in 100/06-34-094-07W5, including during post-Pilot cool-down of the reservoir. Note that temperatures recorded in the 100/04-034-094-07W5 horizontal were measured immediately adjacent to the heater, and so were materially higher than sandface temperatures when the heaters were on.

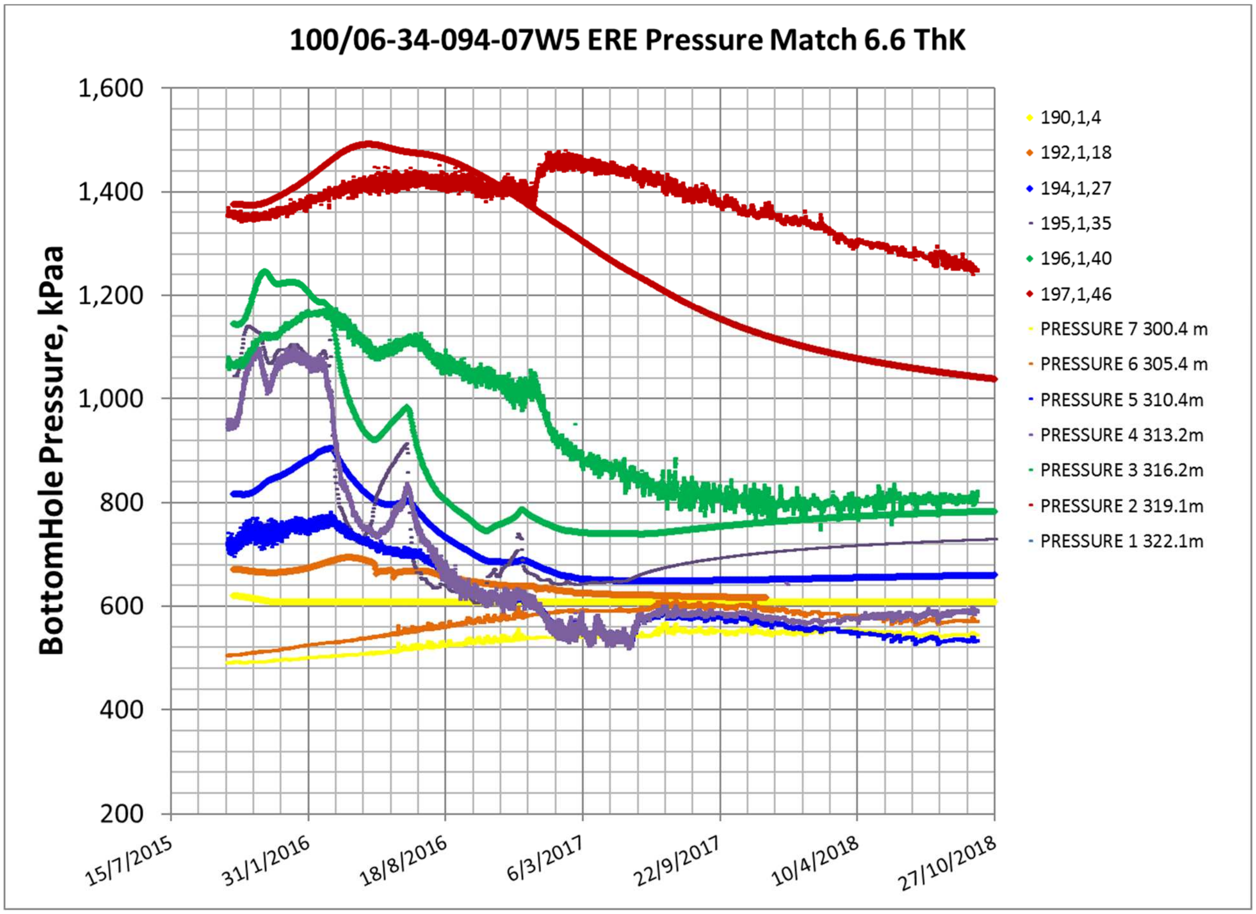


Figure 4-10: 100/06-34-094-07W5 Initial Pressure Match

While a temperature match at the observation wells was readily achieved with the coupled heating and production model developed for the LEAD Pilot, matching of pressures at the observation wells has been much more challenging. Figure 4-10 presents the initial pressure model predictions versus pressures measured in 100/06-34-094-07W5, showing significant discrepancies with less pressure drawdown at the observation well than was predicted by the model (honoring actual production levels). Matching efforts have focused on tuning layer-specific horizontal and vertical permeabilities in the reservoir, and on allowing slight reduction of irreducible water in the presence of heat. Figure 4-11 presents latest model predictions versus pressures measured in 100/12-34-094-07W5. While the pressure match is significantly improved, the model still fails to accurately match measured production levels (assuming they were consistent along the horizontal).

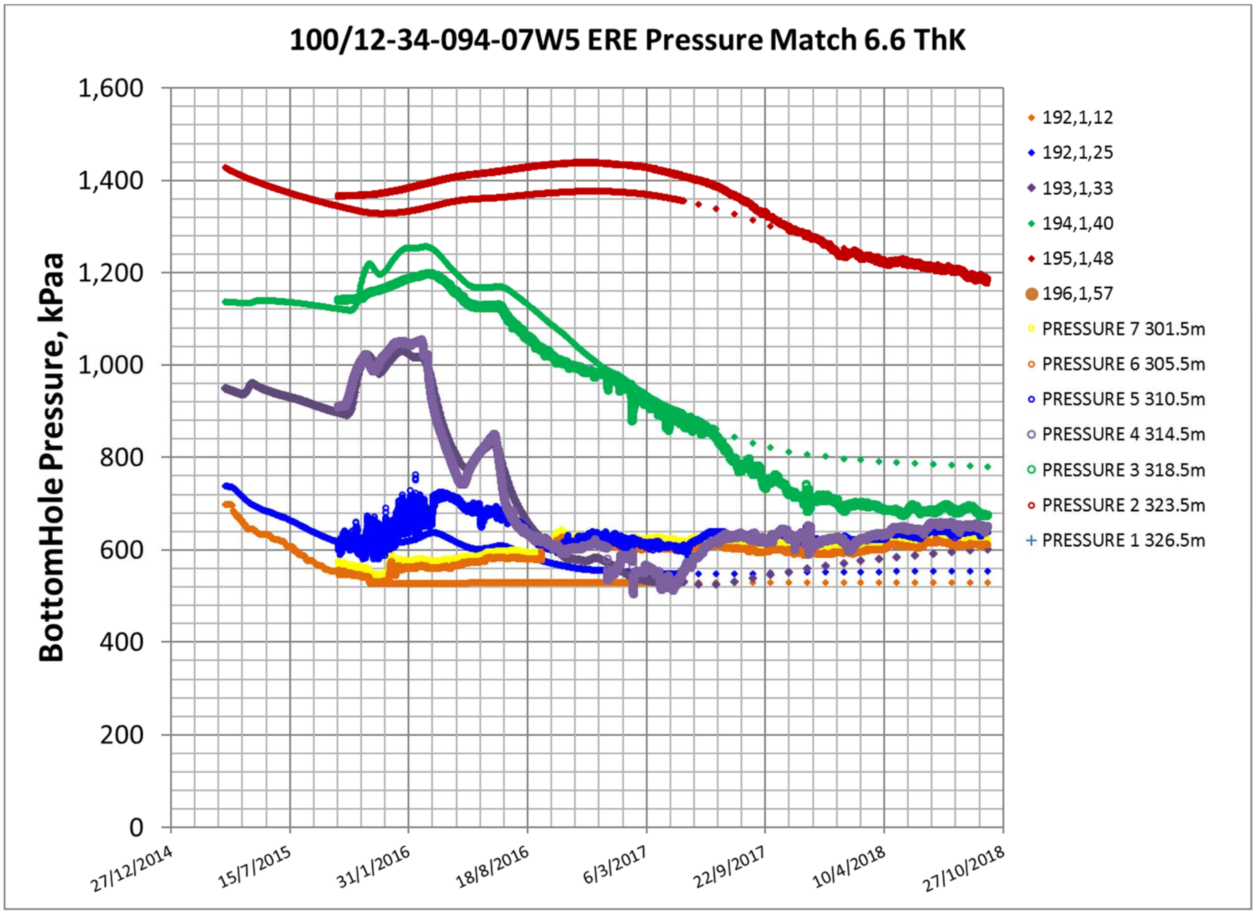


Figure 4-11: 102/12-34-09407W5 Current Pressure Match using CMOST and Asphaltene Deposition Model

4.3.1 Hot Spots

It was noted that the hot spots correlated strongly with high points along the slightly undulating horizontal wellbore trajectory. Heater settings were limited to limit maximum temperature at the hot spots to 270 deg C (to protect the DTS), and to the extent that hot spot temperatures were significantly higher than the average temperature in the lateral, this limits heat injection in to the reservoir.

Various theories were discussed to explain the presence of the hotspots, including convective effects in the heated wellbore fluid. However more recently it was noted that localized hot spots tended to endure during heated flowback, even near the heel of the well, where the “mixing cup” temperature of fluids recovered from distributed regions of the reservoir along the wellbore would be expected to prevail. It is therefore believed that indicated DTS temperatures are influenced significantly by proximity to or direct contact with the heater cables, in particular resulting from potential articulation of the cables and DTS around the completion string at high curvature locations, and that heating of the reservoir was actually fairly uniform. This interpretation is consistent with observed reduction of temperature differentials in a relatively short period of time following any deactivation of the heaters.

Incorporation of fluid injection in future LEAD applications will further improve temperature conformance in the lateral.

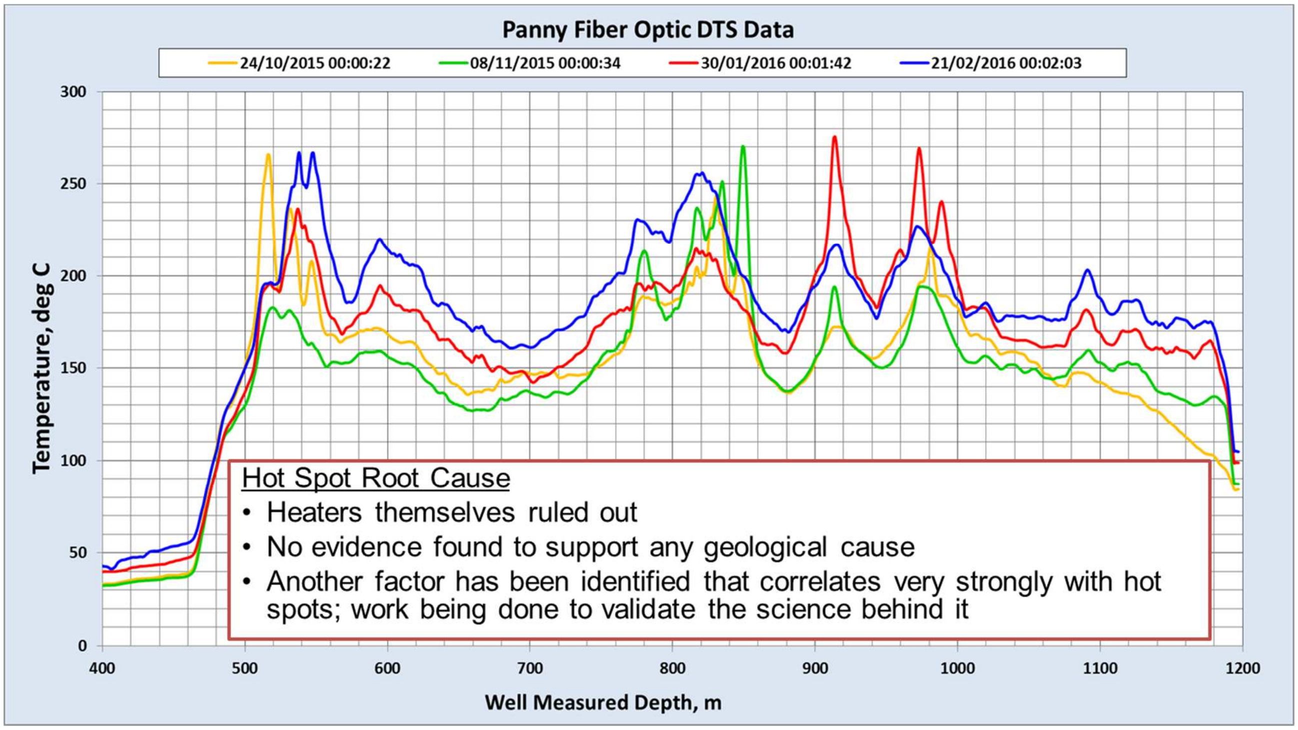


Figure 4-12: 4-34-94-7W5 Fiber Optic Temperature Measurements – Hot Spots

5 Pilot Data

Types of data gathered, and analysis performed by year and Analyses in table 5-1

Table 5-1: Data Gathered and Analyses

	Geology and Geophysics	Lab studies	Simulations	Reservoir Data	Other	
2013	Petrophysical Assessment		Planning			
2014	Clay Morphing	Oil Analyses	Wellbore suitability for Thermal Operation	Formation Damage	Critical Salinity Test	Net Effect Diffusion
2015	Detail Core Analyses		History Matching			
2016		Oil Analyses	History Matching	Injection Test		
2017		Oil Analyses	History Matching			

5.1 Core Lab Testing

5.1.1 Core Samples for Lab Testing

Perpetual conducted the following analyses on the 100/13-34-094-07W5 core for this Pilot project:

1. Heavy Oil Characterization Testing
2. Routine Heavy Oil Core Analysis
3. Petrographic and Reservoir Quality Assessment

The core sample locations are shown on Figure 5-1.

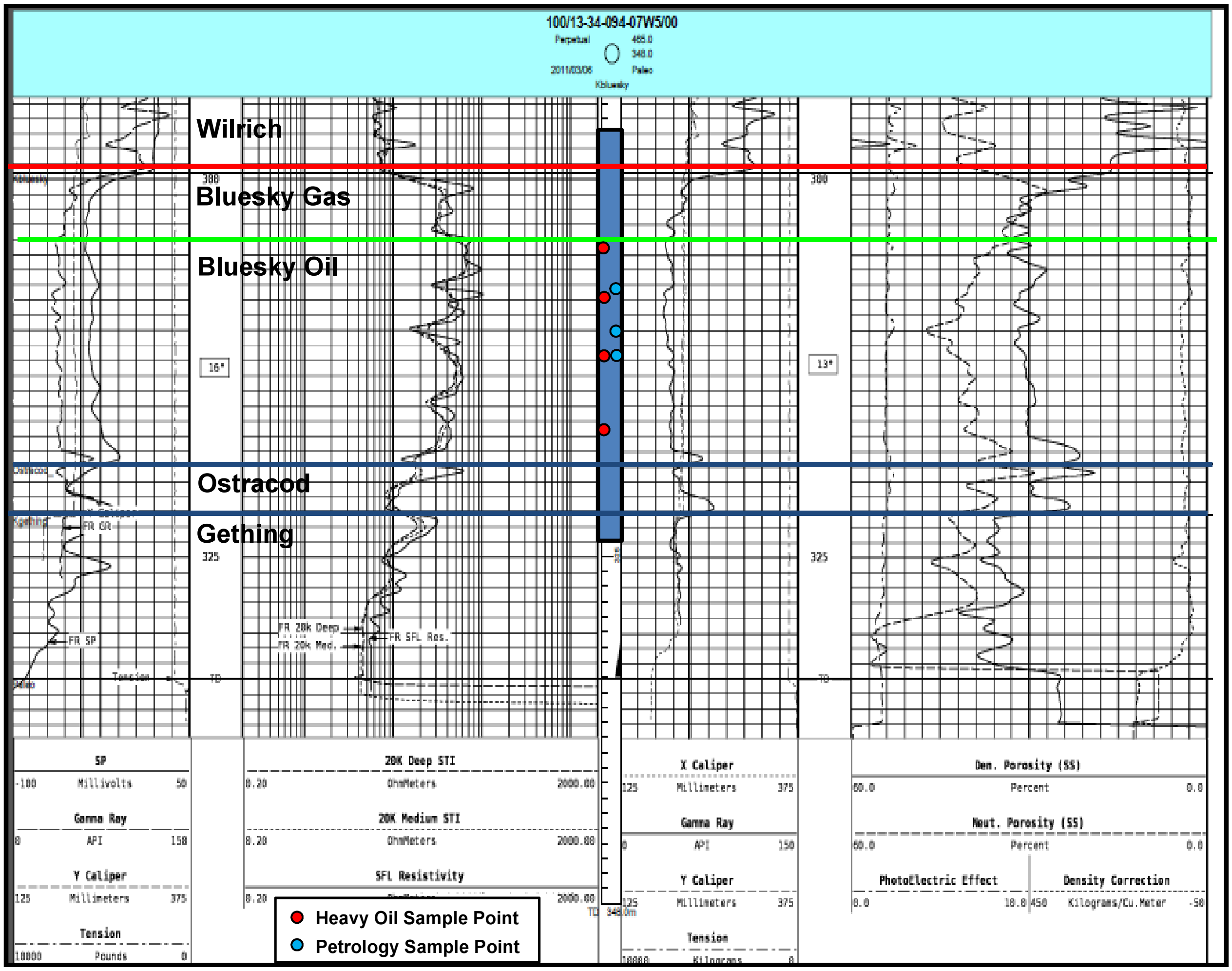


Figure 5-1: Reference Core Sample Locations on 100/13-34-094-07W5

5.1.2 Heavy Oil Characterization – Density & Viscosity

Heavy Oil Characterization testing was conducted by AGAT Laboratories in March 2011 on frozen core taken from 100/13-34-094-07W5. Four sample points from the core were taken to characterize the heavy oil properties (see Figure 5-1).

The results of the heavy oil analyses are summarized in Table 5-2.

Table 5-2: Heavy Oil Density & Viscosity Characterization Summary

Sample ID	Depth Interval (m)	Location	Density (15 °C) (g/cc)	Specific Gravity(A)	API Gravity (°API)	Kinematic Viscosity (cSt)			Absolute Viscosity (cP)		
						25 °C	38 °C	50 °C	25 °C	38 °C	50 °C
Sample 1	304.27 - 304.57	100/13-34-095-04W5M/00	0.9873	0.9882	11.69	9,200	2,490	900.1	9,031	2,426	871.3
Sample 2	307.89 - 308.23	100/13-34-095-04W5M/00	0.9881	0.9890	11.58	10,645	2,805	1,032	10,459	2,735	999.6
Sample 3	311.60 - 311.93	100/13-34-095-04W5M/00	0.9912	0.9921	11.13	15,571	3,833	1,328	15,346	3,750	1,291
Sample 4	316.50 - 316.83	100/13-34-095-04W5M/00	0.9966	0.9975	10.36	68,866	14,253	4,179	68,248	14,024	4,085

The extrapolated viscosity of the Panny heavy oil is shown in Figure 5-2.

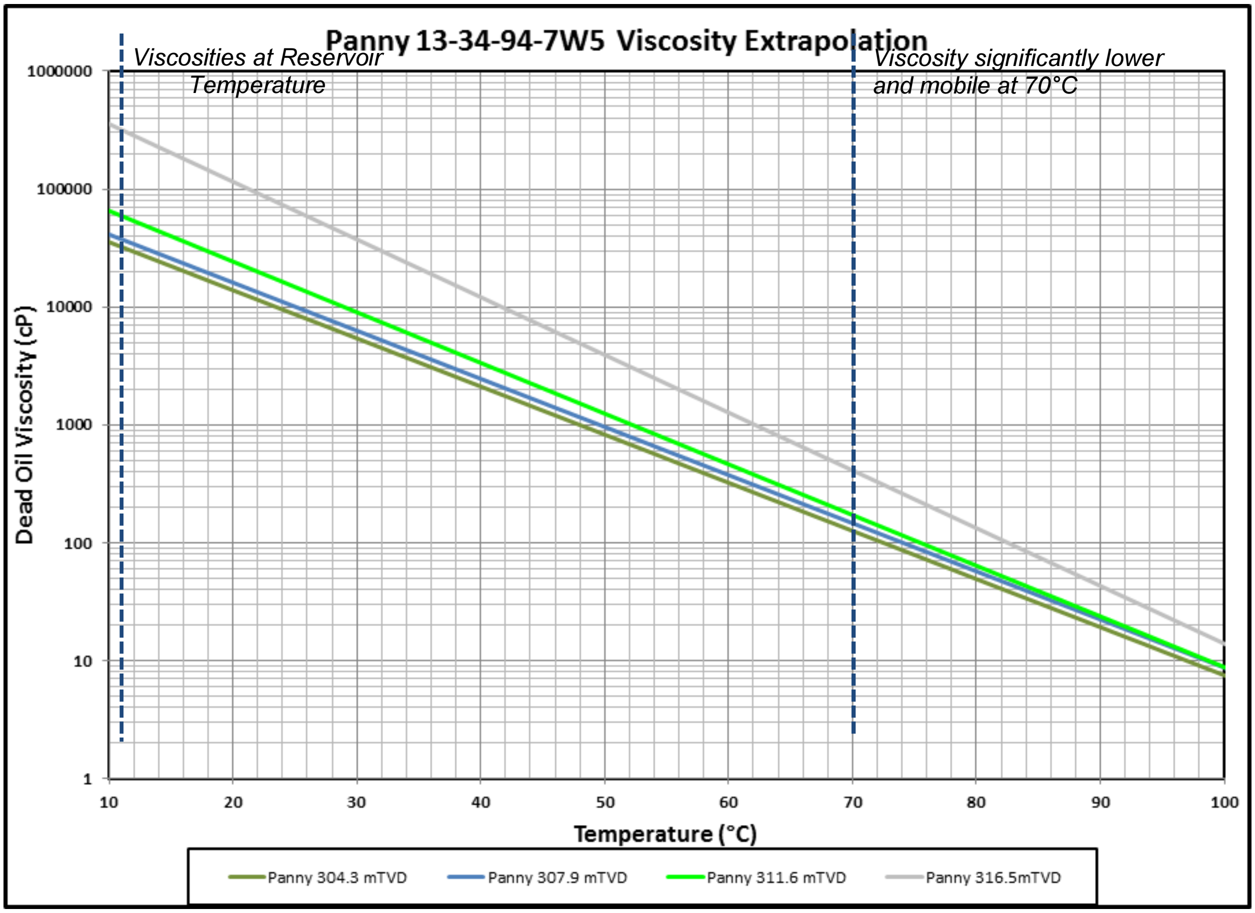


Figure 5-2: Heavy Oil Viscosity Extrapolation Plot (100/13-34-094-07W5)

Per Figure 5-2 at 70 deg C, oil viscosities are less 1,000 cP and oil is predicted to be mobile.

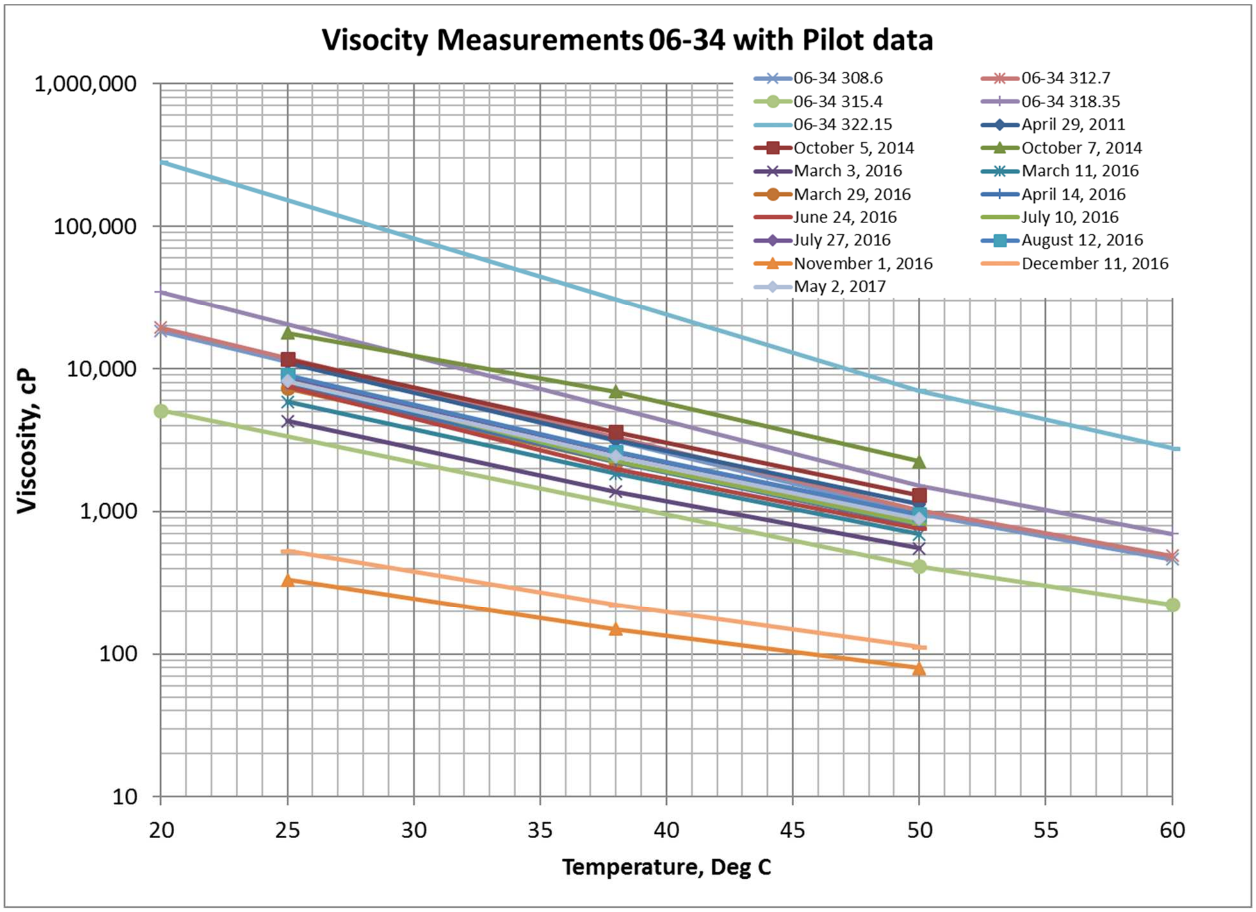


Figure 5-3: Plot of 100/06-34-094-07W5 Core Viscosity Measurements with 100/04-34-94-07W5 Produced Oil Viscosity Measurements Through Time

Figure 5-3 compares 100/04-34-094-07W5 produced oil sample viscosities with estimates of viscosity at various depths along the core extracted from the 100/06-34-94-07W5 observation well. Note that viscosity of the core sample at depth 315.4 m was unexpectedly lower than the samples from other depths. Solvent placed in the 100/04-34-094-07W5 horizontal prior to running the heater for the Pilot (to ensure the wellbore was clear) may have leached to the reservoir, resulting in the baseline viscosity reduction.

All the produced oil samples plotted within expected viscosity band, except for samples that were influenced by the solvent injected to the reservoir during the Pilot.

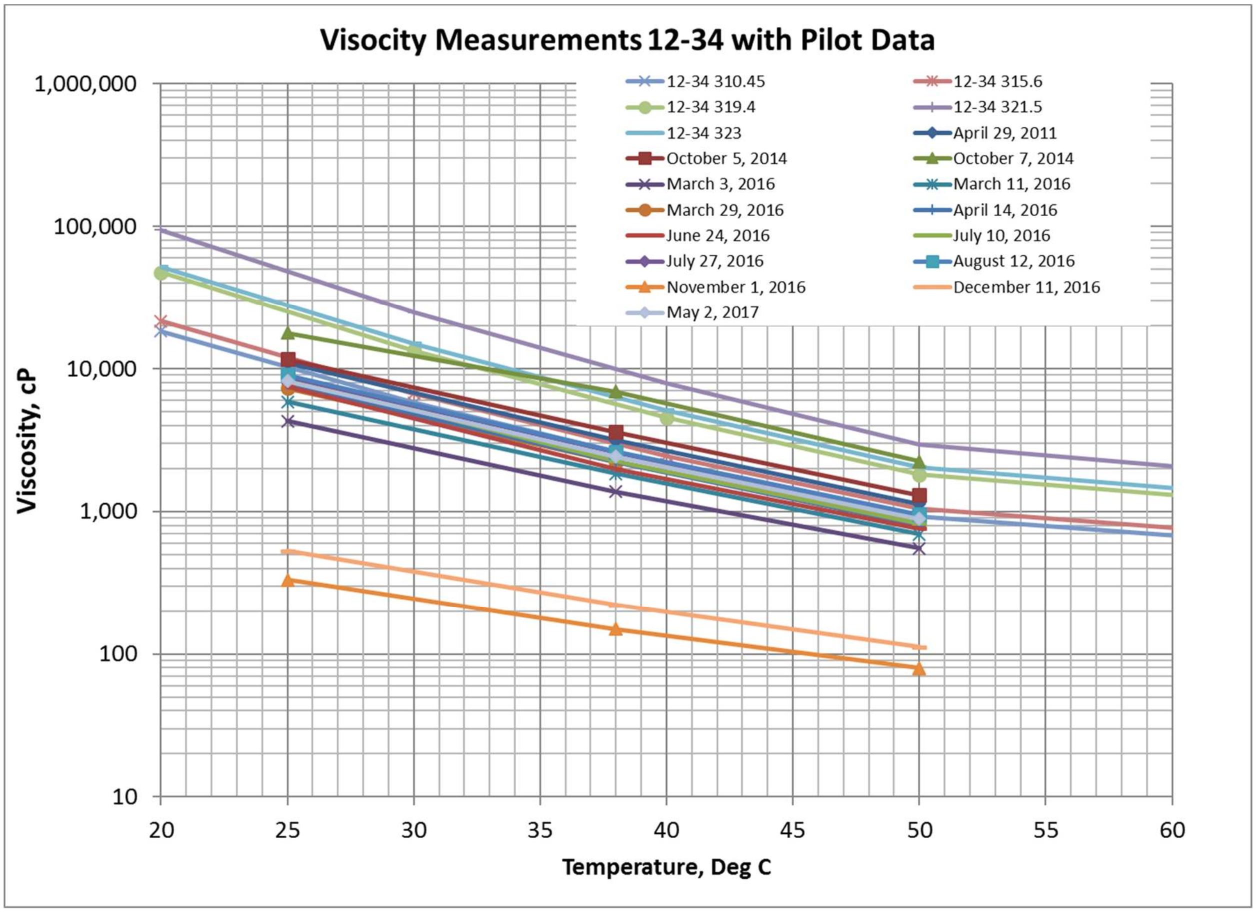


Figure 5-4: Plot of 102/12-34-094-07W5 Core Viscosity Measurements with 100/04-34-94-07W5 Produced Oil Viscosity Measurements Through Time

Figure 5-4 compares 100/04-34-094-07W5 produced oil sample viscosities with estimates of viscosity at various depths along the core extracted from the 102/12-34-94-07W5 observation well. Production after initial heating showed reduced oil viscosities. Oil samples collected post solvent injection again plotted away from the initial analyses denoting lower viscosities.

The primary oil production validated the core viscosity analyses. The produced oil viscosity appeared to shift over time toward the viscosity measured at the top core payer. This could suggest gravity drainage of the upper layers of oil with temperature enhanced mobility, oil refinement due to temperature exposure from the heater, or combination of the two phenomena.

5.1.3 Routine Heavy Oil Core Analysis

A routine heavy oil core analysis was conducted by AGAT Laboratories in April 2011 on frozen core taken from 100/13-34-094-07W5. A total of 19 small plug samples were taken in the retrieved core interval 297.0 – 324.4 mKB. A summary of the analyses results is provided in Table 5-3.

Table 5-3: Heavy Oil Core Analysis Results Summary

Zone	SID	TOP	BOTTOM	POROSITY	GD	KMAX	KV	KV/KH	BMF_So	BMF_Sw	PV_So	PV_Sw	CalcPorosity
Wilrich	NA	297.00	299.30										
	OB001	299.30	299.75	0.19	2705	45	16	0.36	0.03	0.04	0.38	0.62	0.16
	OB002	299.75	300.21	0.30	2656	549	181	0.33	0.05	0.08	0.38	0.62	0.27
	OB003	300.21	302.17	0.27	2638	238	126	0.53	0.03	0.08	0.28	0.72	0.26
Bluesky Gas	OB004	302.17	302.80	0.32	2626	6141	1599	0.26	0.05	0.09	0.36	0.64	0.30
	004A	302.80	303.36	0.27	2638	238	126	0.53	0.03	0.08	0.28	0.72	0.26
	OB005	303.36	303.87	0.34	2630	6592	5930	0.90	0.08	0.07	0.55	0.45	0.32
	OB006	303.87	304.15	0.21	2835	26	18	0.69	0.05	0.03	0.63	0.37	0.19
Bluesky Oil	OB007	304.15	304.57	0.35	2619	7184	3963	0.55	0.09	0.07	0.57	0.43	0.33
	OB008	304.57	304.83	0.35	2621	5753	3887	0.68	0.09	0.07	0.57	0.43	0.33
	OB009	304.83	306.20	0.37	2644	3076	2362	0.77	0.09	0.06	0.59	0.41	0.33
	NA	306.20	306.35										
	OB010	306.35	307.89	0.39	2630	6480	3073	0.47	0.11	0.07	0.61	0.40	0.37
	OB011	307.89	309.12	0.37	2643	3323	2970	0.89	0.09	0.08	0.53	0.47	0.36
	OB012	309.12	310.86	0.39	2620	4168	2414	0.58	0.10	0.09	0.54	0.46	0.37
	OB013	310.86	311.98	0.36	2619	3147	3077	0.98	0.10	0.06	0.65	0.35	0.33
	OB014	311.98	312.85	0.37	2624	2549	2088	0.82	0.10	0.06	0.64	0.36	0.34
	OB015	312.85	314.15	0.36	2641	1823	1778	0.98	0.11	0.05	0.67	0.33	0.33
	OB016	314.15	315.50	0.35	2617	3180	2133	0.67	0.11	0.04	0.71	0.29	0.32
	OB017	315.50	317.04	0.35	2631	2258	1043	0.46	0.09	0.07	0.56	0.44	0.33
	OB018	317.04	317.80	0.26	2629	248	140	0.56	0.06	0.04	0.62	0.38	0.24
	NA	317.80	321.77										
Ostracod	OB019	321.77	323.40	0.37	2626	609	547	0.90	0.11	0.06	0.65	0.35	0.35
Gething	LC	323.40	324.40										

A sample of the core photos taken in the Bluesky formation is provided in Figure 5-5.

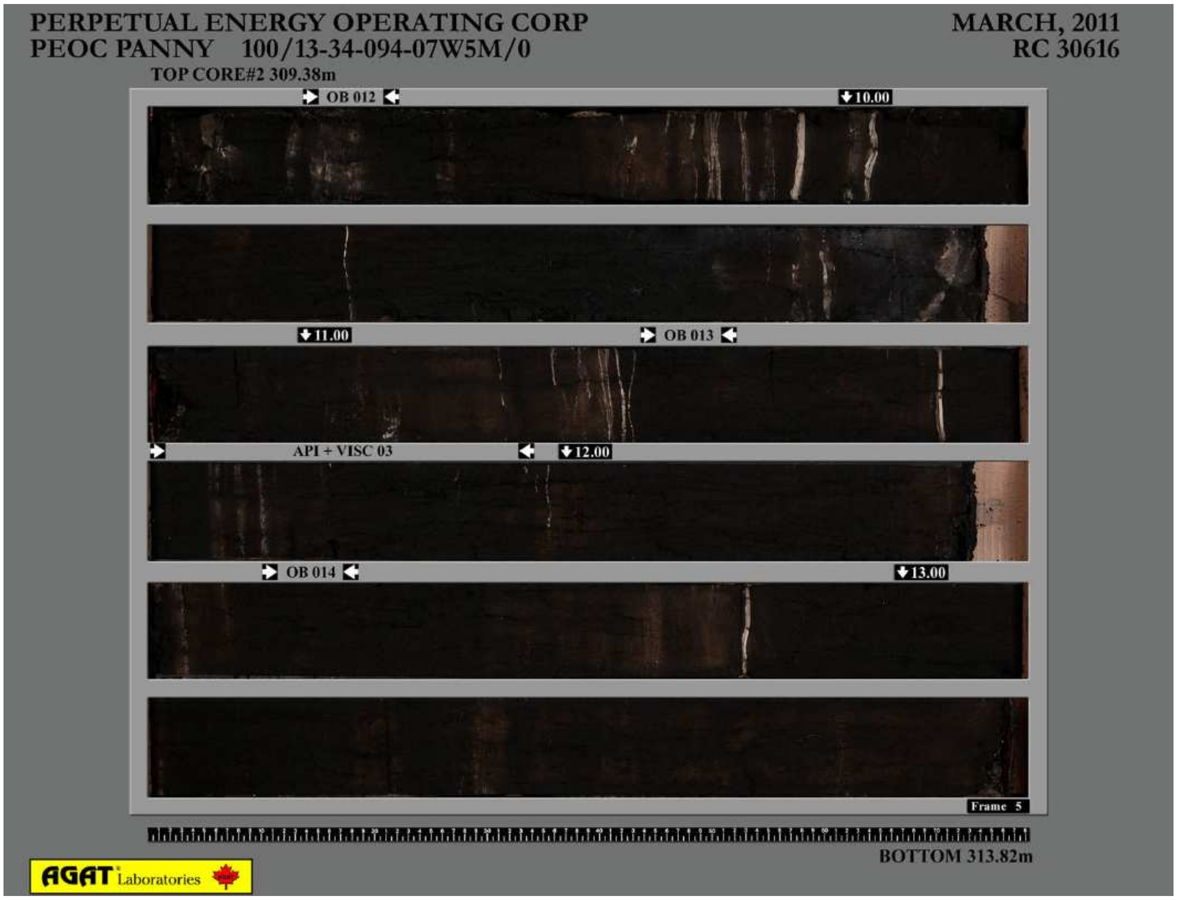


Figure 5-5: 13-34-94-7W5 Sample Core Photo of Bluesky Interval

5.1.4 Petrographic and Reservoir Quality Assessment

A Petrographic and Reservoir Quality Assessment was conducted by GR Petrology Consultants Inc. in May 2013 on frozen core taken from 100/13-34-094-07W5. A total of 3 samples were taken from the retrieved core (see Figure 5-1). Thin section, x-ray diffraction, scanning electron microscopy, and grain size analyses were conducted. A summary of the analyses results is provided in Table 5-4.

Table 5-4: Petrographic Sample Summary from 13-34-94-7W5

Sample Name	Sample Location	Thin Section	XRD	SEM	Grain Size
GR-001	307.19 mKB	No	Yes	Yes	Yes
GR-002	310.00 mKB	Yes	Yes	Yes	Yes
GR-003	311.70 mKB	No	Yes	Yes	Yes

In the report, GR Petrology noted:

"Good reservoir quality (GR-003) to very good reservoir quality Bluesky Formation sandstones, cored between 307.19m and 311.70m in the 100/13-34-094-07W5 well, represent poorly consolidated, upper fine grained to lower medium grained chertarenites. All intervals are moderately sorted to moderately well sorted.

The 100/13-34-094-07W5 Bluesky samples are characterized by very good total porosity, showing little variability between the samples. Total core analysis porosity is respectively 36.5%, 36.4% and 36.5% for samples GR-001 to GR-003. Effective porosity for sample GR-002, determined by modal analysis, is 22.2%. Depending on the volume of matrix and pseudomatrix components, the mean grain size, the degree of compaction and the volume of emplaced cements, the 100/13-34-094-07W5 Bluesky sandstones show good horizontal permeability (2550mD: GR-003) to very good horizontal permeability (3320mD and 3150mD in samples GR-001 and GR-002 respectively). Average core analysis total porosity and horizontal permeability values for the three 100/13-34-094-07W5 samples are respectively 36.5% and 3007mD (average very good reservoir quality)."

Tabularized results can be found in Tables 5-5 to 5-7.

Table 5-5: Bulk Fraction X-Ray Diffraction Data (100/13-34-094-07W5)

GR Sample #	Sample ID	Qtz	KFd	Plag	Dol	Pyr	Cal	Sid	Kaol	Ill	Chl	M-L	Smec	Total Clay
GR-001	307.19	68.3	9.2	7.5	2.6	1.5	1.2	1.3	5.0	2.5	0.9	-	present	8.4
GR-002	310.00	71.5	4.6	5.6	1.8	1.7	1.3	1.7	8.5	2.6	0.7	-	present	11.8
GR-003	311.70	68.5	7.3	7.3	1.6	1.9	1.3	1.2	6.2	4.1	0.6	-	-	10.9

Qtz - Quartz - SiO_2
KFd - Potassium Feldspar - $KAlSi_3O_8$
Plag - Sodium Feldspar - $NaAlSi_3O_8$
Dol - Dolomite - $CaMg(CO_3)_2$
Pyr - Pyrite - FeS_2
Cal - Calcite - $CaCO_3$
Sid - Siderite - $FeCO_3$
Kaol - Kaolinite - $Al_2Si_2O_5(OH)_4$
Ill - Illite - $(K,H_3O)Al_2Si_3AlO_{10}(OH)_2$
Chl - Chlorite - $(Mg,Fe,Al)_6(Si,Al)_4O_{10}(OH)_8$
M-L - Mixed Layer
Smec - Smectite - $(Na,Ca)_{0.3}Al_2(Si,Al)_4O_{10}(OH)_2 \cdot xH_2O$
Total Clay - Kaol+Ill+Chl+M-L+Smec

All units are in percent unless otherwise noted.

Table 5-6: Less Than 2 Micron Glycolated Clay Fraction Z-Ray Diffraction Data (13-34-094-07W5)

GR Sample #	Sample ID	Total Clay in Bulk Sample	Total Smectite in Bulk Sample	Kaolinite	Illite	Chlorite	Mixed Layer	Smectite
GR-001	307.19	8.6	0.28	74.4	16.2	6.1	-	3.3
GR-002	310.00	11.8	0.26	70.6	22.1	5.1	-	2.2
GR-003	311.70	10.9	-	79.0	14.2	6.8	-	-

All units are in percent unless otherwise noted.

Table 5-7: Grain Size Data (100/13-34-094-07W5)

Sample #	Depth (m)	Mean (mm)	Max (mm)	Min (mm)	Standard Deviation
GR-001	307.19	0.240	0.504	0.077	0.091
GR-002	310.00	0.260	0.503	0.096	0.083
GR-003	311.70	0.257	0.553	0.110	0.073

5.1.5 Laboratory Studies - Formation Damage

Based on petrology work conducted in 2013, Perpetual investigated possible formation damage that might occur due to clays during the LEAD process. On April 3, 2014, Weatherford Labs concluded the following tests on the 100/13-34-094-07W5 core:

1. Critical Velocity Test

   a. Tested for possible permeability reduction due to clay plugging at pore throats induced by fluid movement
2. Critical Salinity Test
   a. Tested for possible permeability reduction due to swelling clays when subjected to fresh water
3. Clay Morphing Reactor Test
   a. Tested for the possible transformation/morphing of certain clays and minerals into other clays and minerals at elevated temperatures

5.1.6 Critical Velocity Test

For the critical velocity test, two native-state sample plugs were selected to form one stack to assess the possibility of permeability impairment on reservoir material associated with increasing levels of flow rates of formation brine. Overburden pressure was applied, and the stack was heated to 70°C, and then subjected to injection rates from 10 to 2000 cc/hr. Pre- and post-test SEM and XRD were conducted on the stack. The results indicated a significant increase in permeability with cumulative flow through the stack. The results are summarized in Figure 5-6.

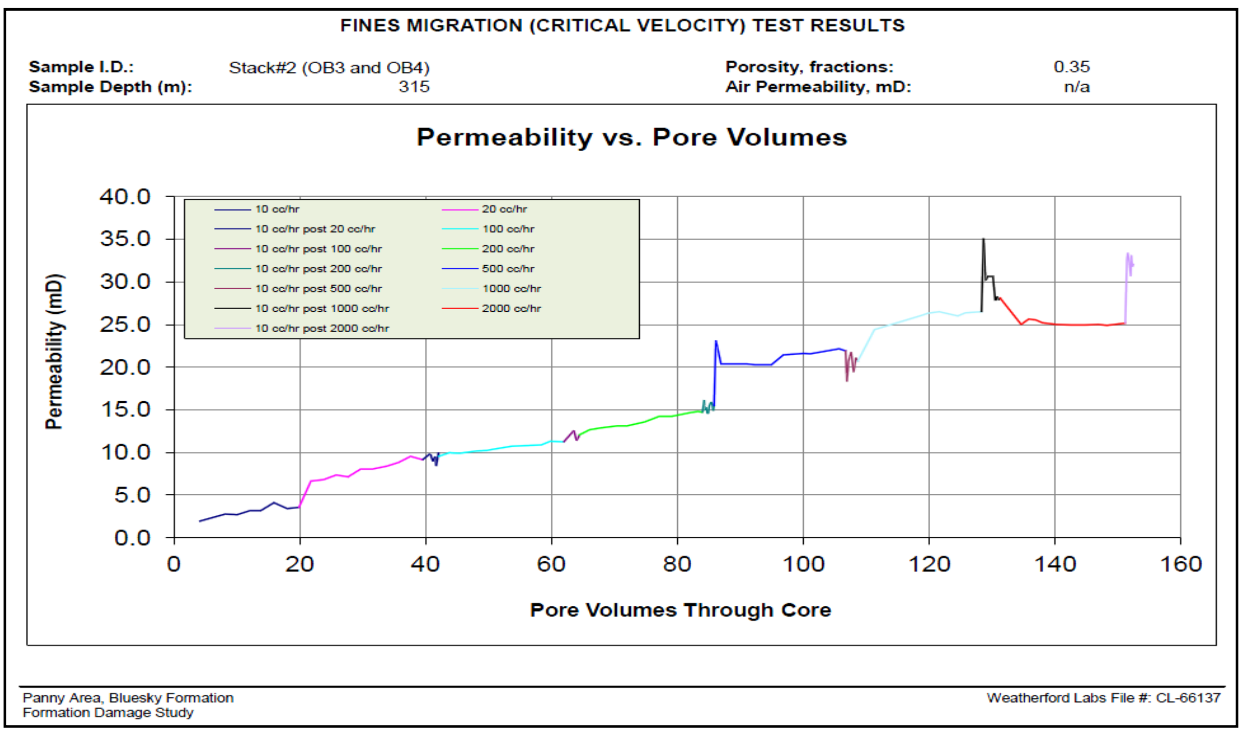


Figure 5-6: Critical Velocity (Fines Migration) Test Results

These test results coupled with the pre- and post-test XRD and SEM analysis indicate that mobilization of fines occurred (primarily kaolinite and mobile silica fines), and had the effect of enhancing permeability. In addition to fines mobilization, XRD and SEM showed evidence of dissolution of magnesium calcite, siderite, carbonate cements, unstable clasts, feldspar, and the etching of kaolinite crystals. All these may have contributed to enhanced reservoir permeability.

While this test coupled with the petrology study indicated that permeability enhancement occurred, further study may be considered in the future to understand whether the fines have the potential to plug pore throats in lower quality areas of the reservoir and cause corresponding permeability reduction.

5.1.7 Critical Salinity Test

For the critical salinity testing, two native-state samples were selected and assembled as one stack to evaluate possible permeability impairment on reservoir material associated with decreasing levels of saline fluids. Overburden pressure was applied, and the stack was heated to 70°C, then four fluids with salinity ranging from 30,832 TDS (formation brine) down to 831 TDS (sourced injection water) were tested at a constant injection rate of 20 cc/hr. The results are summarized in Figure 5-7.

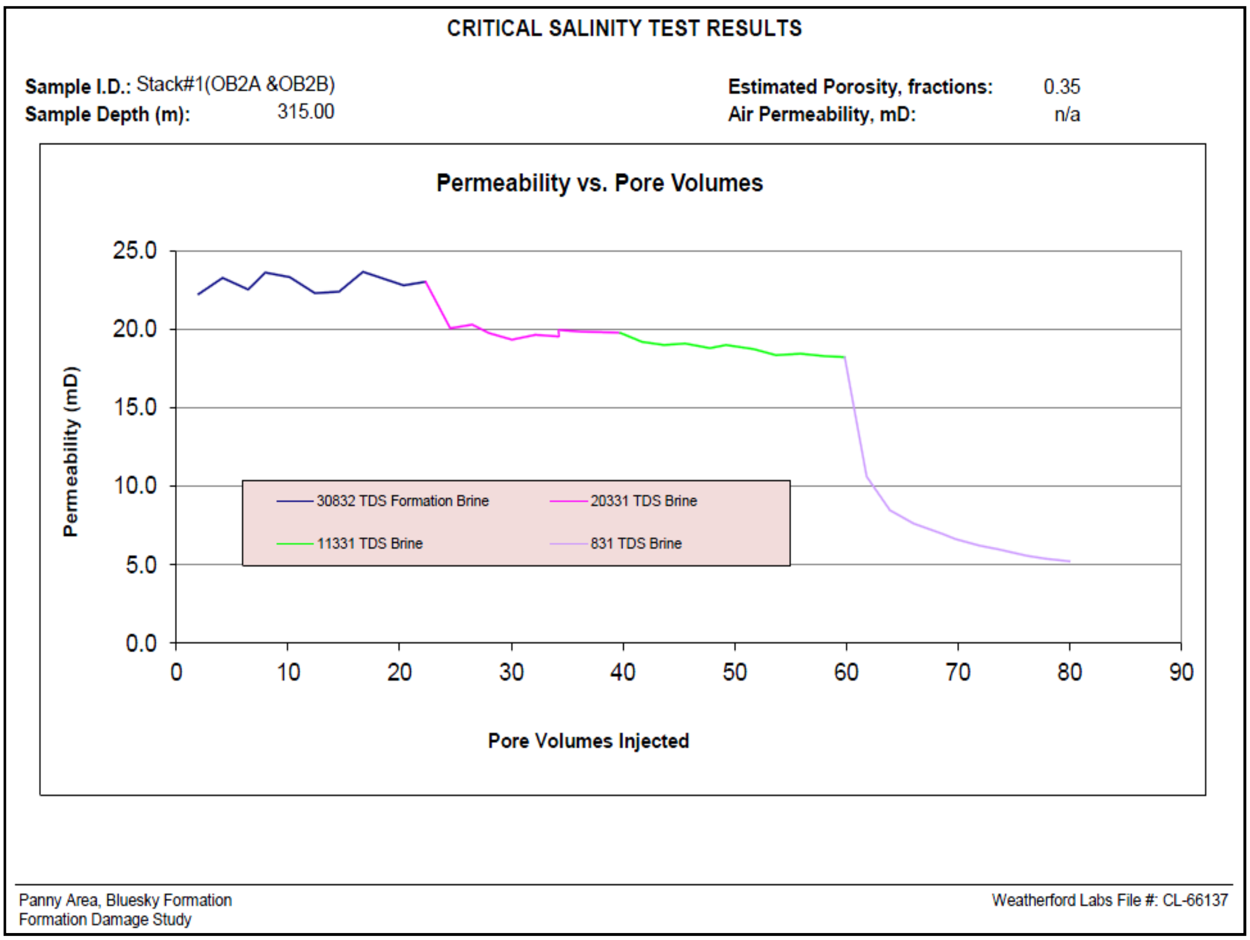


Figure 5-7: Critical Salinity Test Results

These results indicate that the reservoir may have some sensitivity to fresh water, supported by evidence of minor development of pore lining illite and smectite rich clays in the post-test SEM analysis. Further investigation on additional core points distributed throughout the reservoir through various facies may be warranted to better understand the potential extent of these effects.

5.1.8 Clay Morphing Reactor Test

For the clay morphing reactor test, a sample was selected for testing in a heated reactor. The test was conducted at 240°C and 2,965 kPaa (430 psia). Steam was injected at a rate of 10 cc/hr for a period of 15 days. The post-test sample was subjected to XRD analysis and a comparison was made with pre-test XRD. The results are summarized in Figure 5-8 and Table 5-8.

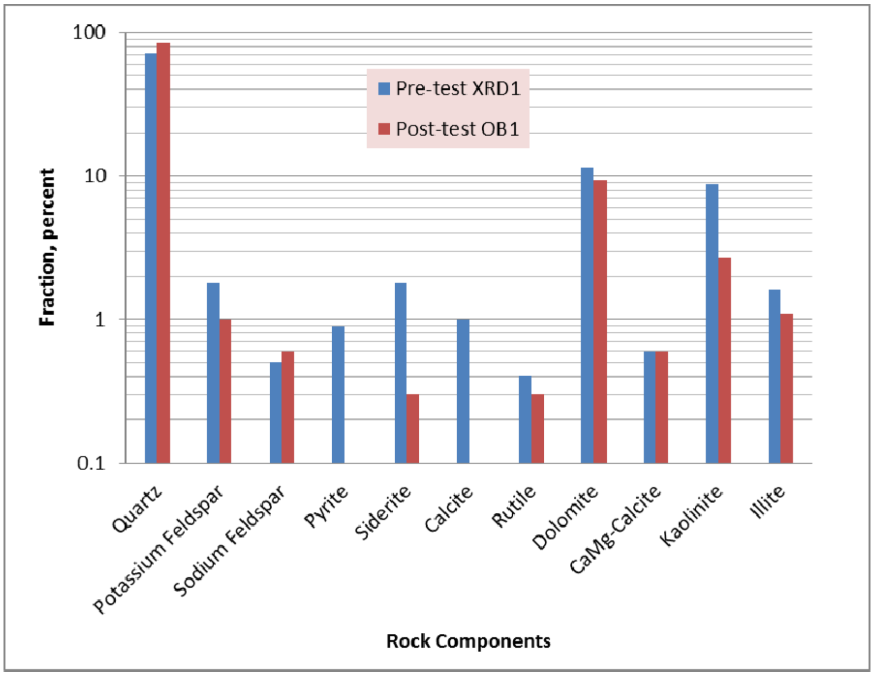


Figure 5-8: Reactor Testing XRD Results Comparison

Table 5-8: Reactor Testing XRD Results

BULK FRACTION X-RAY DIFFRACTION DATA																	
GR Sample #	Sample ID	Depth (m)	Qtz	KFd	Plag	Pyr	Sid	Cal	Rut	Dol	CaMg	Kaol	Ill	Chl	M-L	Smec	Total Clay
GR-001	XRD1; Pre Test	310.20	71.3	1.8	0.5	0.9	1.8	1.0	0.4	11.4	0.6	8.7	1.6	-	-	-	10.3
GR-004	OB1; Post Test	310.20	84.0	1.0	0.6	-	0.3	-	0.3	9.4	0.6	2.7	1.1	trace	-	present	3.8

Qtz - Quartz - SiO_2
KFd - Potassium Feldspar - $KAlSi_3O_8$
Plag - Sodium Feldspar - $NaAlSi_3O_8$
Pyr - Pyrite - FeS_2
Sid - Siderite - $FeCO_3$
Cal - Calcite - $CaCO_3$
Rut - Rutile - TiO_2
Dol - Dolomite - $CaMg(CO_3)_2$
CaMg - Calcite - $(Ca,Mg)CO_3$
Kaol - Kaolinite - $Al_2Si_2O_5(OH)_4$
Ill - Illite - $(K,H_3O)Al_2Si_3AlO_{10}(OH)_2$
Chl - Chlorite - $(Mg,Fe,Al)_6(Si,Al)_4O_{10}(OH)_8$
M-L - Mixed Layer
Smec - Smectite - $Na_{0.3}Mg_3(Si,Al)_4O_{10}(OH)_2 \cdot {}_6H_2O$
Total Clay - Kaol+Ill+Chl+M-L+Smec

The results of this test show a net decrease in clay and increase in quartz. A significant reduction of kaolinite and illite occurred, coupled with a trace addition of smectite and chlorite. Overall this indicates some alteration of mineralogy can be expected during a thermal process that will reach or exceed temperatures of 240°C.

5.1.9 Net Effect Discussion

These tests conclude that this reservoir may have some level of reaction to a thermal water injection process such as LEAD, and help to isolate potential root cause effects. However, with the critical velocity showing permeability enhancement due to fines mobilization and mineral dissolution, the critical salinity showing a permeability reduction at low salinities, and the clay morphing test revealing minerals morphing especially with decrease in total clay, the net effect of all these combined with respect to the LEAD process remains unknown. Further investigation through lab or field work to determine the potential net effect should be considered.

5.1.10 Water Source Well

A water source well was drilled on the 13-34-94-7W5 Pilot lease from July 25 to 28, 2013 to a total depth of 58.5m. A water aquifer was encountered, and a screen was installed from 55.5 – 58.5 m. The well was developed for a number of hours by the drilling rig, then rig released and allowed to settle for a little over two weeks.

On August 13, 2013 a pump test commenced to determine the productivity of the water source well. The well tested at pump rates of 18 L/min (26 m3/d) consistently for 8 hours. However, the pump screen then started plugging off after this point due to silt. Rates were reduced to 4-6 L/min (5-9 m3/d), but were not sustainable, and the pump test was stopped at 9 hours. Recovery of fluid level after pumping stopped was good.

Based on this initial test data, Perpetual believes that a second Water Source Well ("WSW") will be required for the future Stage 2 LEAD Pilot, targeting ~120 m3/d. A second WSW also provides water source redundancy to assure consistent Pilot operation.

Targeting ~120 m3/d total water source rates by adding a 2nd WSW will require an Observation well to be drilled under current regulations. Perpetual plans to drill the future 2nd WSW and the Observation well at the same time and test all three wells together in advance of submitting an application under the Water Act, contingent on proceeding with LEAD Stage 2.

5.1.11 Injection Test on 13-34-94-7W5 Vertical Well

An injection test into the vertical well 100/13-34-094-07W5, was conducted between March 14-25, 2014. The downhole pressure recorders were removed on July 3-4, 2014.

The objectives of this test were to:

1. Determine a reservoir fracture pressure for the regulatory scheme application.
2. Gather current and accurate bitumen pressures to compare to gas cap pressures.
3. Determine if a bulk vertical permeability could be estimated.

The downhole setup for this test is shown in Figure 5-9. The well was originally drilled and perforated from 311.0-316.0 mKB to cold produce bitumen from the Bluesky reservoir. Perforations were added for this test between 307.0-307.5mKB, and a tubing string with dual packers was set to isolate the two sets of perforations from each other and from the wellbore annulus. This tubing string contained 3 pressure recorders, measuring each isolated zone. Additionally, a pressure recorder was placed at surface during the injection testing.

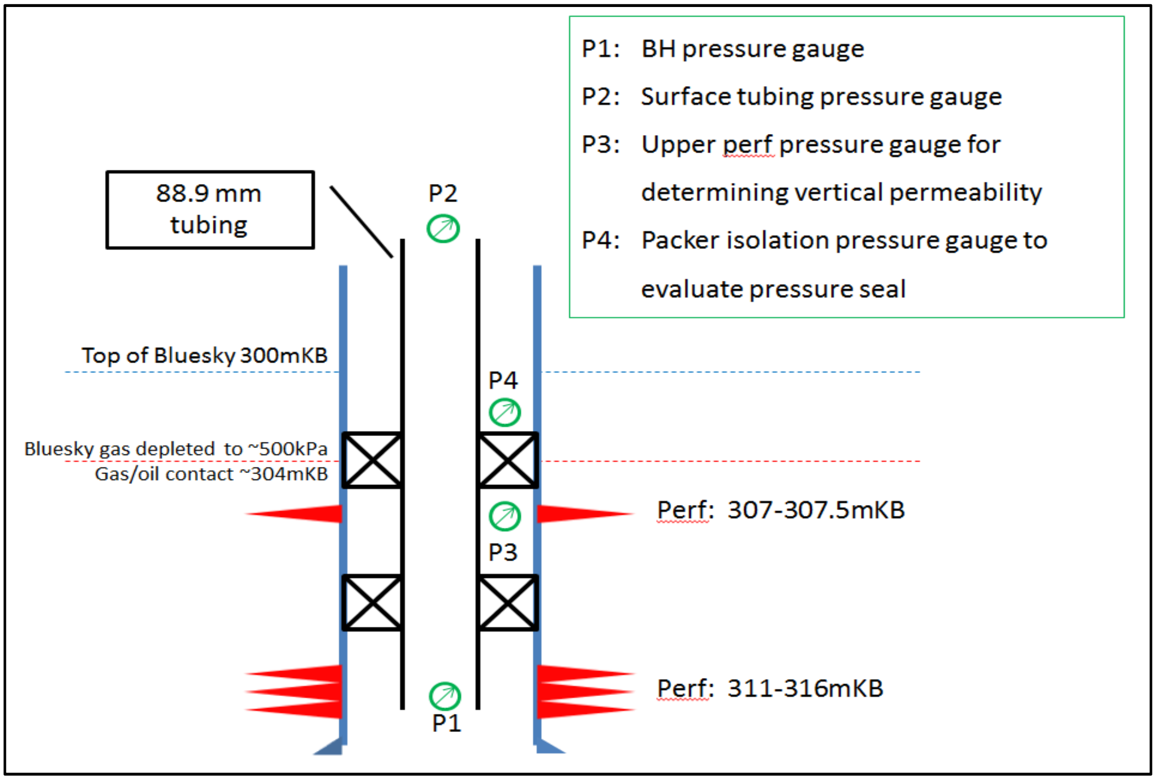


Figure 5-9: Well Configuration for Injection Test at 100/13-34-094-07W5

The injection test was conducted using 3% KCl water injected into the tubing. Four cycles were completed to collect multiple data points and due to some mechanical pumping equipment issues. The results of the test specific to the objectives are discussed in the sections below.

After the injection test was complete, the wellbore remained isolated with the packers and pressure recorders in place for approximately 3 ½ months to allow reservoir pressure stabilization. The pressure recorders were then pulled, and the data reviewed.

5.1.12 Reservoir Fracture Gradient

During the fourth injection cycle the rate was increased until a break-down signature appeared, indicating a fracture was propagating (Figure 5-10). This fracture breakdown occurred at a rate of 144m3/d (100L/min) and a pressure of 7,305kPaa. Pumping continued for approximately another 7 minutes prior to shut-down. The final pumping rate was 100L/min at 7,164kPaa. No visible ISIP was observed at shut-down likely due to the very low injection rate (100L/min), the shallow depth of the perforations, and the large tubing size (3-1/2", 88.9 mm). It is therefore reasonable to conclude that the fracture extension pressure corresponds to the final pumping pressure of 7,164kPaa.

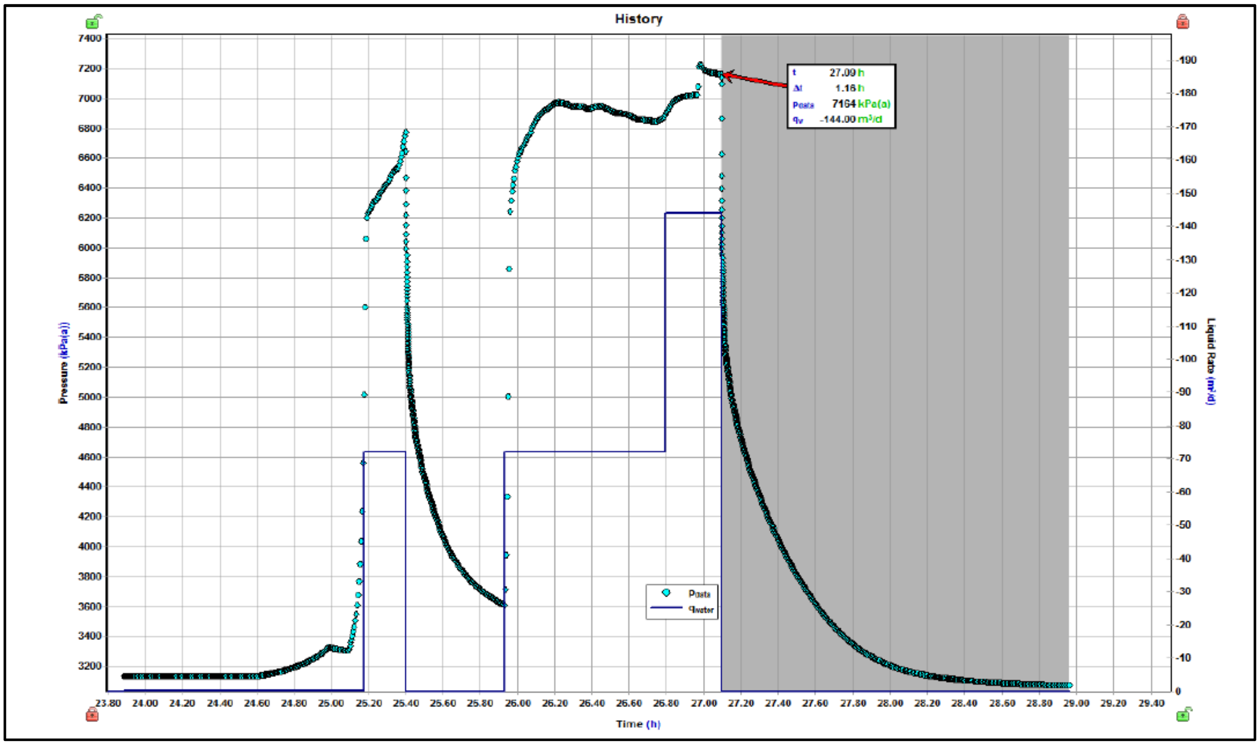


Figure 5-10: Injection Test Data at 100/13-34-094-07W5

Using the surface data from gauge P2, fracture closure pressure was determined using the procedures outlined in SPE 163825, *Interpretation of Closure Pressure in the Unconventional Montney using PTA Techniques*, Robert Hawkes et al. This closure pressure was measured to be 5,492kPaa using the specialized diagnostic plot illustrated in Figure 5-11.

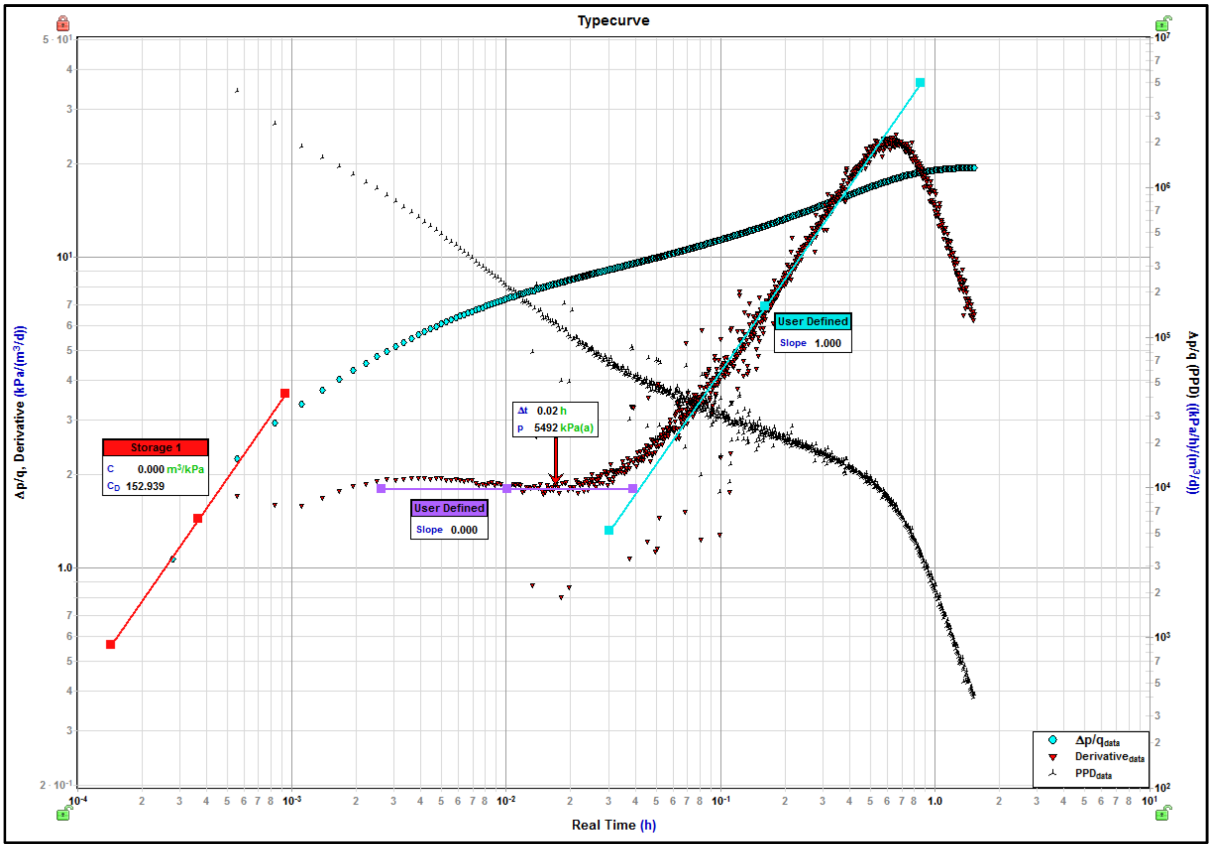


Figure 5-11: Application of Closure Pressure Calculation using PTA techniques from SPE 163825

The measured fracture closure pressure of 5,492 kPaa equates to a closure gradient (closure pressure/depth) of 5,492 kPaa/311 mKB = 17.66 kPa/m. This high gradient likely corresponds to the overburden stress, suggesting the fracture was oriented in the horizontal plane, and is not likely to propagate vertically.

This data enabled Perpetual to establish a Maximum Operating Pressure (MOP) approved by the AER of 5,250 kPag bottomhole (2,250 kPag wellhead MOP) under the Experimental Scheme Approval.

5.1.13 Bitumen Pressures during Test

The virgin reservoir pressure of the Panny Bluesky reservoir was 1920 kPaa, but as the top gas has been produced over the years the gas pressure in this area is now down to approximately 500 kPaa. What hasn't been recorded recently is the bitumen pressure.

The pressure recorders P1 and P3 (as found in Figure 5-9) stabilized over time to the current reservoir pressure, summarized in Table 5-9.

Table 5-9: Current Reservoir Pressures

Recorder	Measuring	Landing Depth	Stabilized Pressure
P3	Upper Perforations	305.6 mKB	1080 kPaa
P1	Lower Perforations	311.0 mKB	1164 kPaa

Pressure gradient between P1 and P3 was 15.6 kPa/m (higher than hydrostatic), suggesting a non-steady-state pressure distribution between the gas cap and the bitumen. To further resolve the pressure distribution and gradients, the observation wells for this Pilot were equipped with multiple pressure sensors through both the bitumen and the gas cap.

5.1.14 Vertical Permeability Determination

A secondary goal of the injection test was to determine average vertical permeability between the perforated intervals. The test design envisioned pressure response at P3 (Figure 5-9) that would be utilized to calculate in situ permeability. However, the pressure response measured at P3 was inadequate to accurately model and assess permeability ranges.

5.1.15 Report on 4-34 Hz Wellbore Suitability for Thermal Project

The LEAD Pilot utilized the existing horizontal wellbore 100/04-34-094-07W5. This wellbore was cased with J55 grade casing using LT&C couplings and cemented with thermal cement. Perpetual sanctioned Noetic Engineering to assess the suitability of this wellbore, specifically the intermediate casing, for use in the LEAD Pilot.

The report found that the LT&C connections were the primary concern for potential failure and should be subjected to a maximum temperature of 120°C. Further, to prevent the intermediate casing from reaching this maximum temperature it was determined that the heater should be placed at least 5m below the Intermediate Casing Point (ICP).

Perpetual designed the Stage 1 CHS Test accordingly to ensure the intermediate casing did not operate above 120°C, with the heater placed 20m away from ICP to provide a significant margin of safety.

5.1.16 Reservoir Monitoring

Downhole temperature and pressure monitoring plots can be found in Figures 5-12 to 5-16.

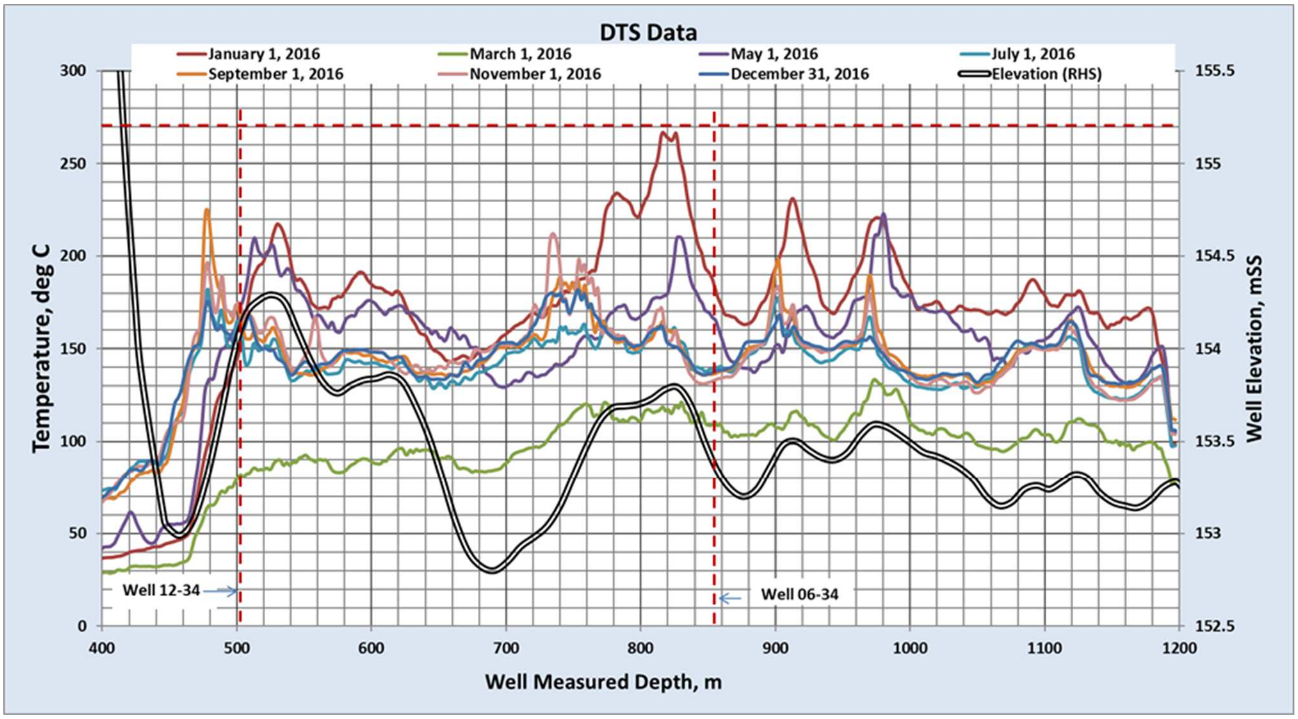


Figure 5-12: 4-34-94-7W5 Fiber Optic Temperature Measurements 2016

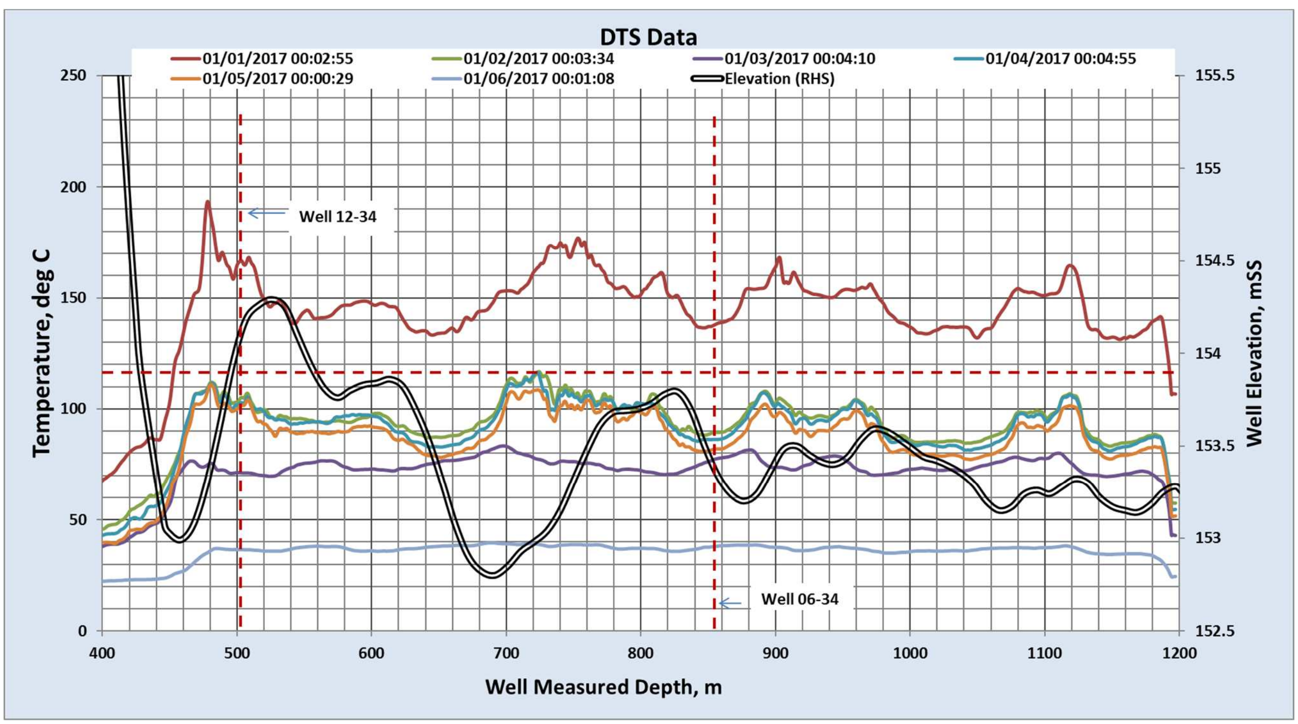


Figure 5-13: 4-34-94-7W5 Fiber Optic Temperature Measurements 2017

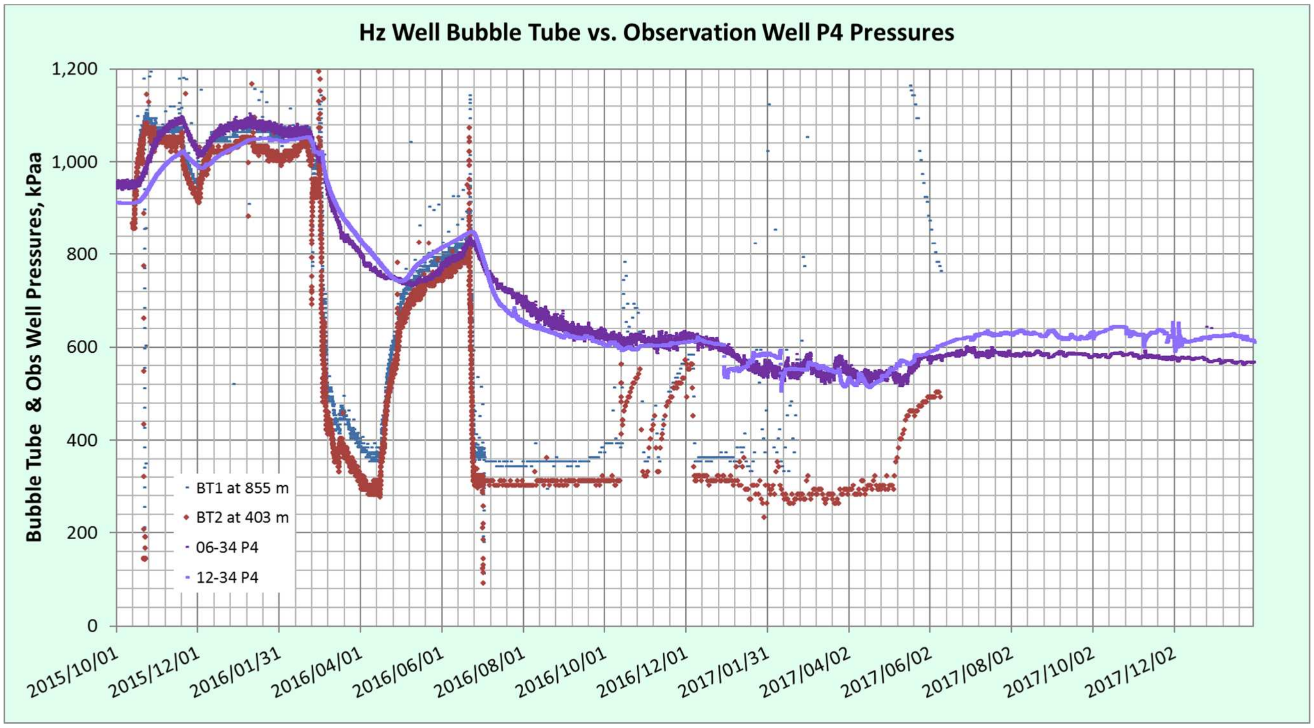


Figure 5-14: 4-34-94-7W5 Bubble Tube Pressures Measurements and P4s in 06-34 & 12-34

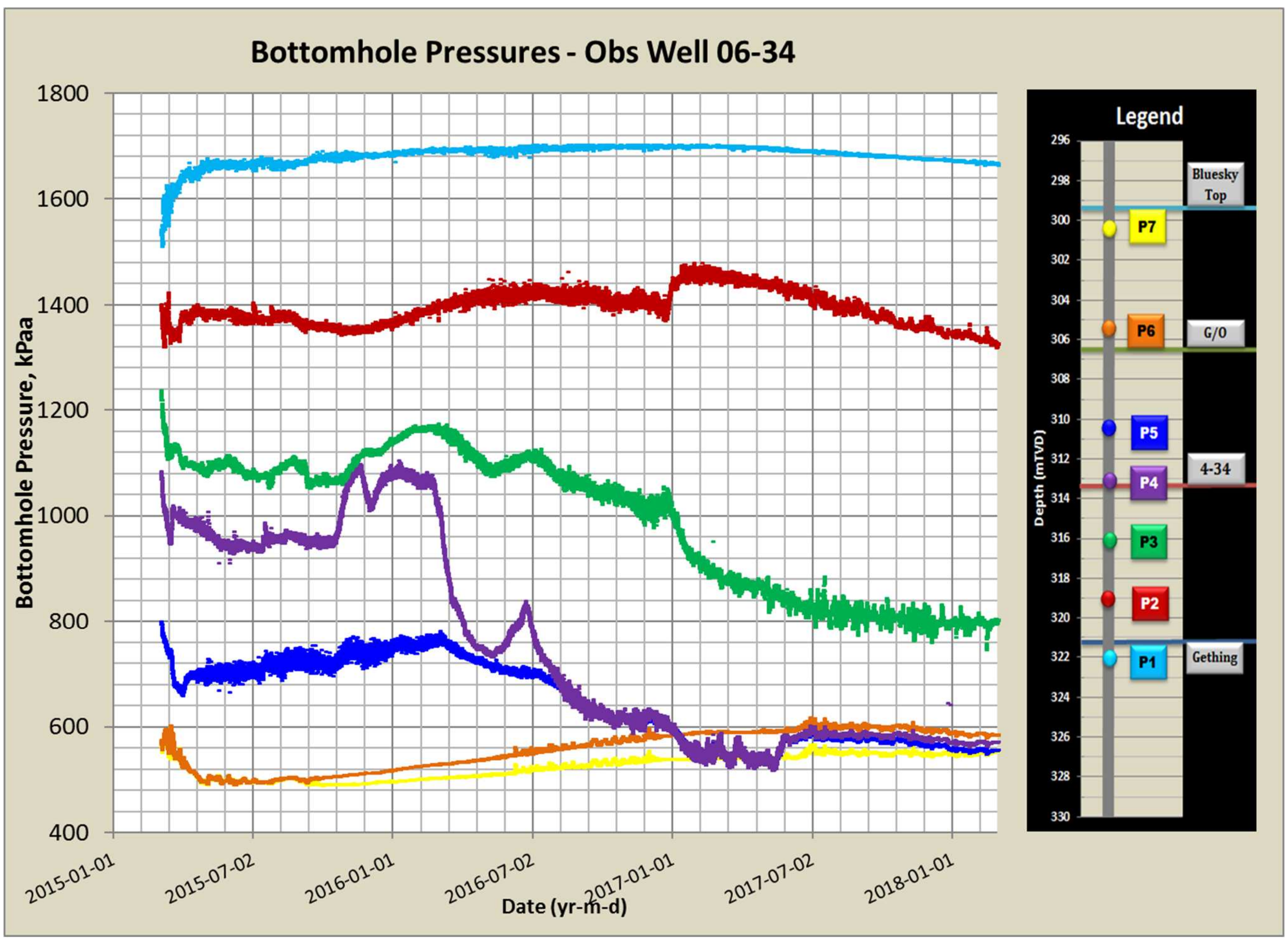


Figure 5-15: 100/6-34-094-7W5 Observation Well Pressures

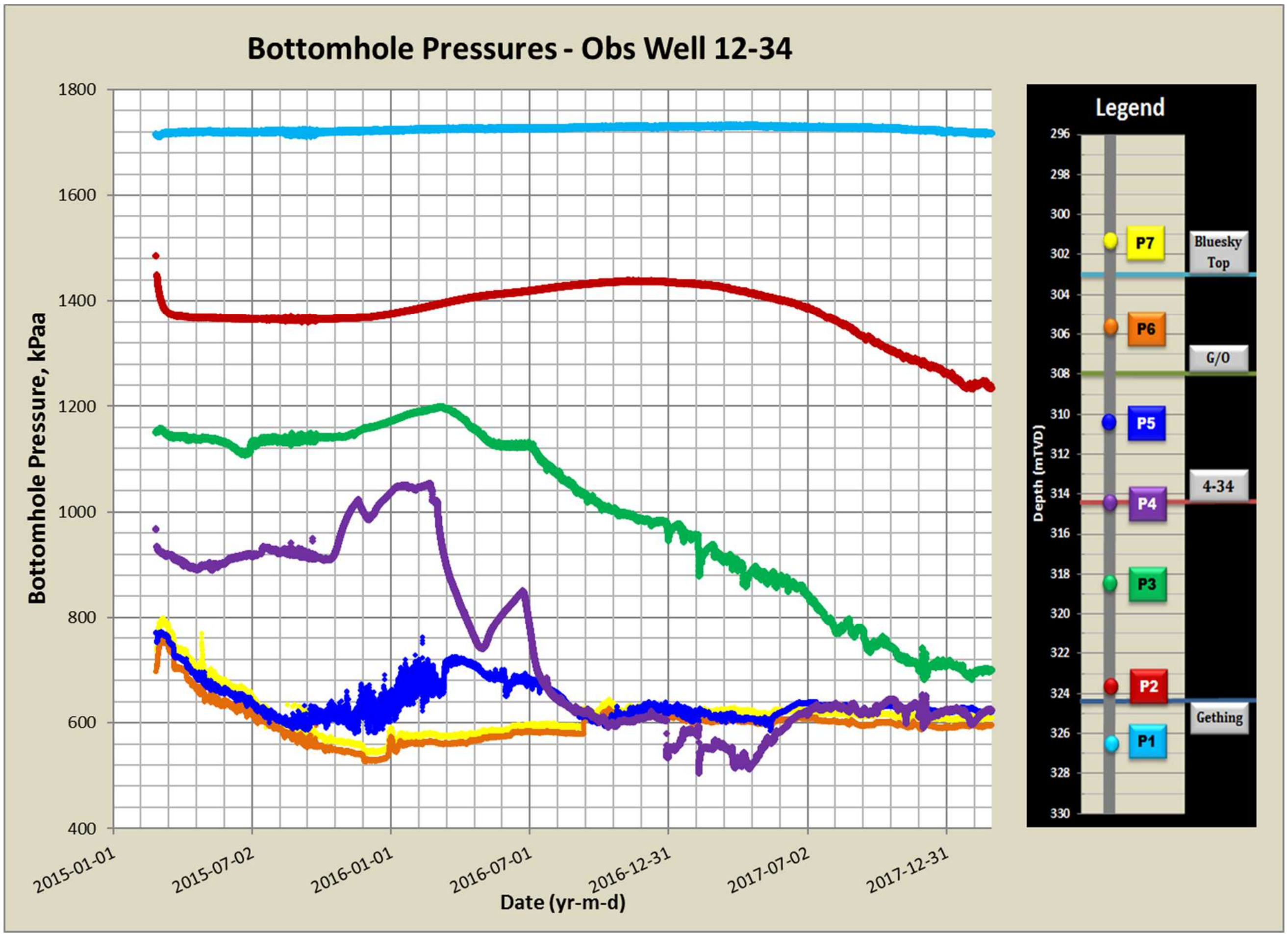


Figure 5-16: 102/12-34-094-7W5 Observation Well Pressures

Per Figures 5-15 and 5-16, Initial pressure gradient in the bitumen was higher than 10 kPa/m; bitumen was interpreted to be in a transient state of equalization with the pressure depleted gas cap. The vertical pressure gradient varied through the reservoir, suggesting variable vertical permeability and/or the potential existence of baffles in the reservoir. These pressure gradients were evident in both the 102/12-34-094-07W5 and 100/06-34-094-07W5 observation wells.

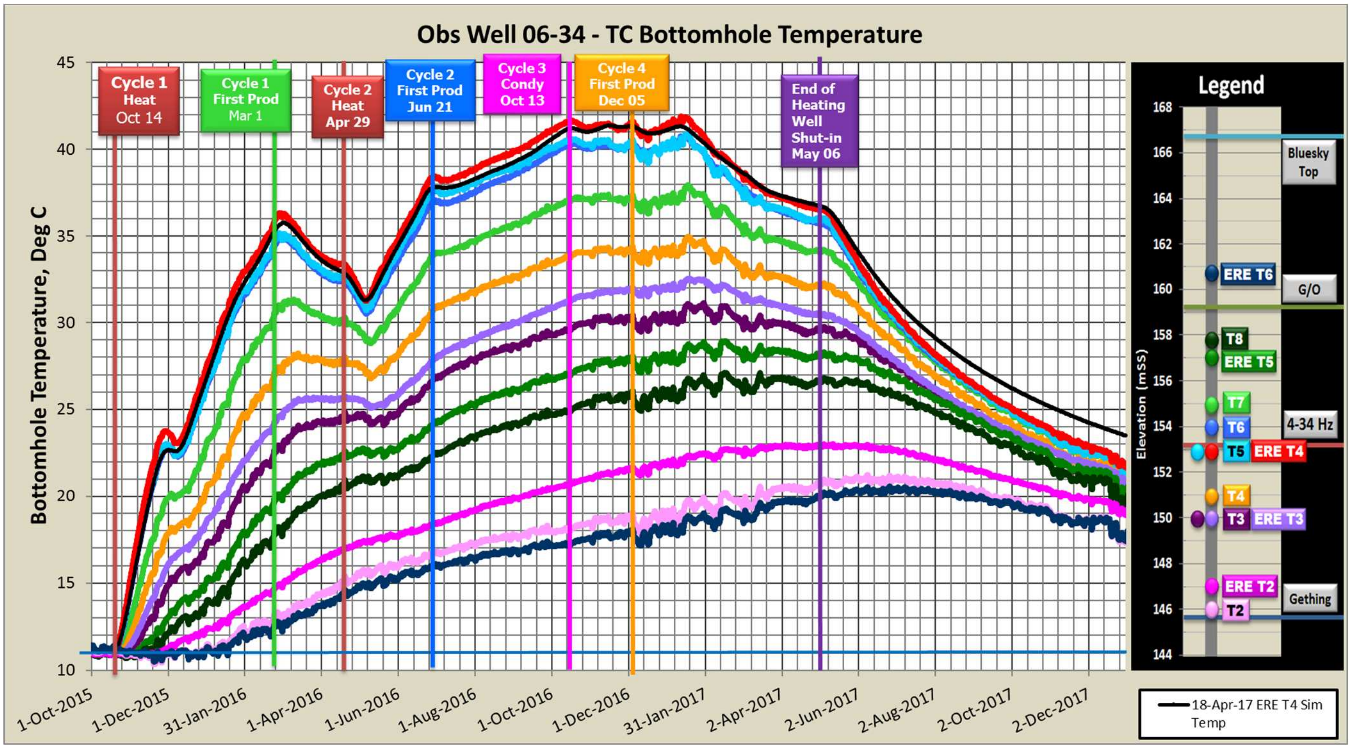


Figure 5-17: 100/6-34-94-7W5 Observation Well Temperatures

Comparing Figures 5-17 and 5-18, the 100/06-34-094-07W5 observation well is closer to 100/04-34-094-07W5 than the 102/12-034-094-07W5 observation well by ~0.5 m, and so registered higher temperatures during heating of 100/04-34-094-07W5.

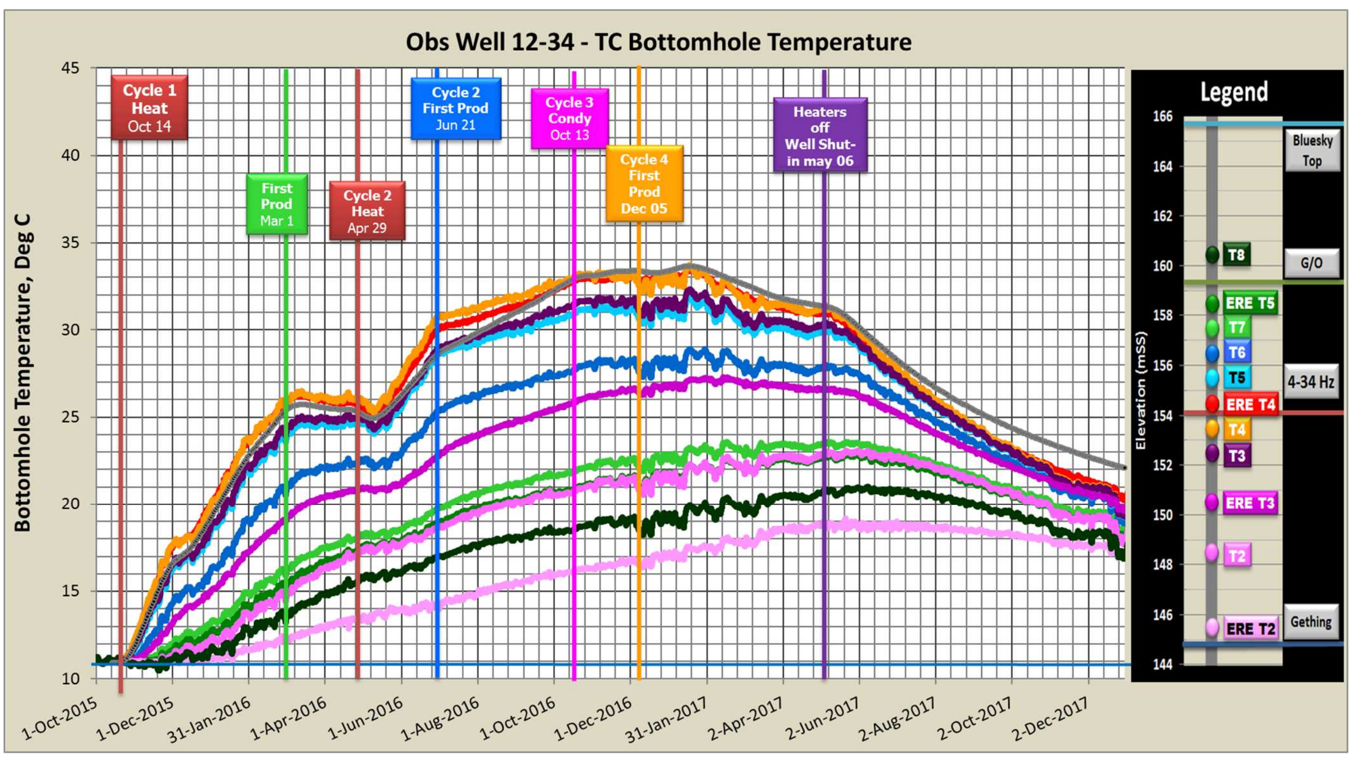


Figure 5-18: 12-34-94-7W5 Observation Well Temperatures

5.2 Interpretation of Pilot Data

The LEAD Pilot utilized a single well with electric heater for both heating and production. The initial plan was for Cyclic Heat Stimulation, with periods of production following periods of heating. However, it was determined during the Pilot that the well could be produced while heating, providing improved flow assurance due to reduced pumping viscosities in the wellbore. This compressed accelerated learnings from the Pilot as a greater portion of the reservoir was heated and investigated, with corresponding additional production. Confirmation of thermal energy transmission into the reservoir while producing was provided by the continuing increase in temperatures at the observation wells during production.

Thermal conductivity of the reservoir was calibrated based on temperatures at the observation wells relative to thermal energy injected at the horizontal. The calibrated thermal conductivity was significantly higher than originally predicted as the reservoir conducted heat more readily than anticipated. However, the significant difference in thermal conductivity did not result in a significant difference in predicted oil production, reflecting the competing effects of higher thermal transmissibility and lower near-wellbore temperatures and corresponding oil mobility.

A follow-on phase was envisioned for the LEAD Pilot wherein water injection would be combined with downhole electric heating to create steam in-situ. Petrology studies conducted as part of LEAD Pilot suggested significant clay content in the reservoir including smectite, and so a water sensitivity study was conducted in the lab to establish minimum salinity content required in the future to prevent swelling of the clays. As well, a fines migration study was conducted to assess risk of pore plugging during water injection. Unfortunately, premature heater failure ultimately lead to the termination of the Pilot prior to water injection tests, and so confirmation of field water salinities required to prevent reservoir damage, and data regarding salt deposition from saline water injection in the wellbore could not be obtained.

It was noted during the Pilot that early time production of oil is approximately proportional to heat injection rate.

Soon after energization of the heater it was observed that elevated temperatures were present at discrete points along the length of the horizontal, and that these points were varying in temperature and shifting along the lateral through time (Figures 4-12, 5-12 and 5-13). It is important to note that the optical fiber DTS measurements during operation of the electric heater cable are reflective of the temperature of the heater cable itself, while during fall-off periods (heaters off), the measurements are more reflective of sandface temperatures. Highest temperature variability occurred within the wellbore during heating; temperature variability in the reservoir was significantly less. As well, temperature variability during heating showed a strong correlation with the moderately undulating trajectory of the horizontal wellbore (highest temperatures at local elevation highs, Figures 5-12 and 5 13) suggesting convective effects in the wellbore.

Vertical permeability and drainage can be a concern with horizontal wells. The observations wells confirmed pressure depletion in the upper layers of the reservoir, corroborating vertical drainage from those layers and suggesting limited areal extent of mud drapes that were evident in the observation well cores.

To preserve integrity of the DTS and ensure optimum horizontal wellbore temperature data collection, maximum temperatures in the wellbore were limited to 270 deg C. This also reduced the risk of clay morphing in the reservoir.

5.2.1 Pressures and Temperatures

While temperature measurements in the observation wells adjacent to 100/04-34-094-07W5 were consistent with results from Perpetual's reservoir simulation models with the new estimated thermal conductivities, pressures at the observation wells exceeded those predicted by the models. Baffling or compartmentalization along the lateral was considered as a possible cause. However, pressure measurements at both observation wells were very similar, and while modeling and pressure history-matching efforts are ongoing, it is believed asphaltene precipitation in the near wellbore region of the reservoir resulting from a pre-Pilot cleanout and residual soak of the wellbore with solvent may have created a skin effect.

Temperature measurements provide insight into the reservoir thermal conductivity and/or diffusivity, suggest values consistent with expected clastic formation values, and are higher than Perpetual's initial estimates.

6 Pilot Economics

6.1 Production Volumes and Revenue

Table 6-1: Production Volumes

Month	Bitumen Production (m3)	Water Production (m3)	Revenue $
Oct-2015	0	0	
Nov-2015	0	0	
Dec-2015	0	0	
Jan-2016	0	0	
Feb-2016	0	0	
Mar-2016	233.1	10.9	
April-2016	21.8	0	21,040.71
May-2016	0	0	18,043.20
Jun-2016	202.2	17	
Jul-2016	261	16.1	8,143.40
Aug-2016	185.1	5.1	53,704.16
Sep-2016	166	14	33,621.87
Oct-2016	20	46.8	31,853.96
Nov-2016	20.3	0	26,382.81
Dec-2016	202.7	11	
Jan-2017	117.7	6.8	34,005.20
Feb-2017	80.73	4	23,343.39
Mar-2017	71.5	4.1	22,149.33
Apr-2017	63.7	5	14,231.92
May-2017	4.2	0.3	20,434.50
Jun-2017	0	0	5,398.07
Jul 2017			
Aug 2017			
Sep 2017			
Oct 2017			
Nov 2017			21,450.73
Dec 2017			

6.2 Revenue

Table 6-2: Revenue Summary

Values in ($'000)	2011	2012	2013	2014	2015	2016	2017	Total
Revenue	0	0	0	0	0	**192.79**	**141.01**	**333.80**

6.3 Capital Costs

No capital costs were incurred beyond 2016.

Table 6-3: 2017 Capital Summary

Cost Type	2017 Cost ($'000)	Description
Drilling	$0	
Completion	$0	
Facility	$0	
Other	$0	
TOTAL	**$0**	

Table 6-4: Capital Summary

Values in ($'000)	2011	2012	2013	2014	2015	2016	2017	Total
Capital	$1,396	$115	$274	$1,207	$7,664	$213	$0	$10,869

6.4 Operating Costs

Operating costs incurred in 2017H1 are detailed in Table 6-5.

Table 6-5: 2017 Operating Cost Summary

Cost Type	2017 Cost ($'000)
Chemicals	$4.5
Contract Services	$6.8
Labour And Field Supervision	$9.5
Miscellaneous And G&A	$20.0
Processing Fees	$0.0
Purchased Energy	$35.0
Rotating Equipment	$23.7
Surface Repairs and Maintenance	$14.5
Transportation Costs	$21.5
Water Hauling	$3.2
Well Servicing / Workovers	$59.9
TOTAL	**$198.6**

Table 6-6: Operating Cost Summary

Values in ($'000)	2011	2012	2013	2014	2015	2016	2017	Total
Operating Costs	$ -	$ -	$ -	$6	$58	$481	$199	$744

6.5 Royalties, Cash Flow

Project cash flows are summarized in Table 6-7.

Table 6-7: Cash Flow

Month	Expenses ($'000)	Royalties ($'000)	Op Income ($'000)
Jan-2016	$24.0	$0.0	-24.00
Feb-2016	$10.7	$0.0	-10.70
Mar-2016	$17.5	$0.0	-17.50
April-2016	$20.1	$2.73	-43.87
May-2016	$40.5	$0.00	-58.54
Jun-2016	$8.6	$0.00	-8.60
Jul-2016	$26.8	$0.15	-35.10
Aug-2016	$23.3	$2.90	-79.91
Sep-2016	$34.0	$2.32	-69.95
Oct-2016	$30.4	$1.79	-64.05
Nov-2016	$24.3	$0.18	-50.87
Dec-2016	$220.3	$0.21	-220.51
Jan-2017	$85.2	$1.97	-121.18
Feb-2017	$38.0	$1.34	-62.68
Mar-2017	$26.1	-$0.45	-47.80
April-2017	$17.2	$0.00	-31.43
May-2017	$16.9	$0.23	-37.56
Jun-2017	$15.1	$0.0	-20.50

6.6 Cash flow

Values in ($'000)	2011	2012	2013	2014	2015	2016	2017H1	Total
Expense	$0	$0	$0	$0	$58	$481	$199	$10,869
Royalties	$0	$0	$0	$0	$0	$10	$3	$13
OP Income	$0	$0	$0	$0	$0	-$684	-$321	-$1,005

6.7 Cumulative Project Costs and Net Revenue

Cumulative project costs are summarized in Table 6-8.

Table 6-8: Cumulative Project Costs

Values in ($'000)	2011	2012	2013	2014	2015	2016	2017H1	Total
Capital	$1,396	$115	$274	$1,207	$7,664	$213	$0	$10,869
Operating Costs	$0	$0	$0	$6	$58	$481	$199	$744
Revenue	$0	$0	$0	$0	$0	-$193	-$141	-$334
Net Revenue	$1,396	$115	$274	$1,213	$7,722	$501	$58	$11,279

7 Facilities

7.1 Description of Major Capital Items

In 2015 the CHS Test Pilot facility was constructed. Major components of this facility include:

- 1 MW natural gas turbine generator (5 x 200kW turbines)
- MCC building including downhole heater transformers & thyristor controllers, site PLC system, HMI computer server system, fiber optic interrogator, and UPS backup
- Fuel gas booster compressor (95 HP)
- Tank farm (750 bbl emulsion tank, 750 bbl sales tank, 750 bbl spare tank)
- Hydraulic engine skid
- 65 kW backup diesel generator
- Fuel gas line tied-in from 8-33-94-7W5 well site
- Communications tower
- Bubble tube panel with nitrogen packs

Facility pictures can be found in Figures 7-1 & 7-2.

Figure 7-1: LEAD Pilot CHS Test Facility looking North

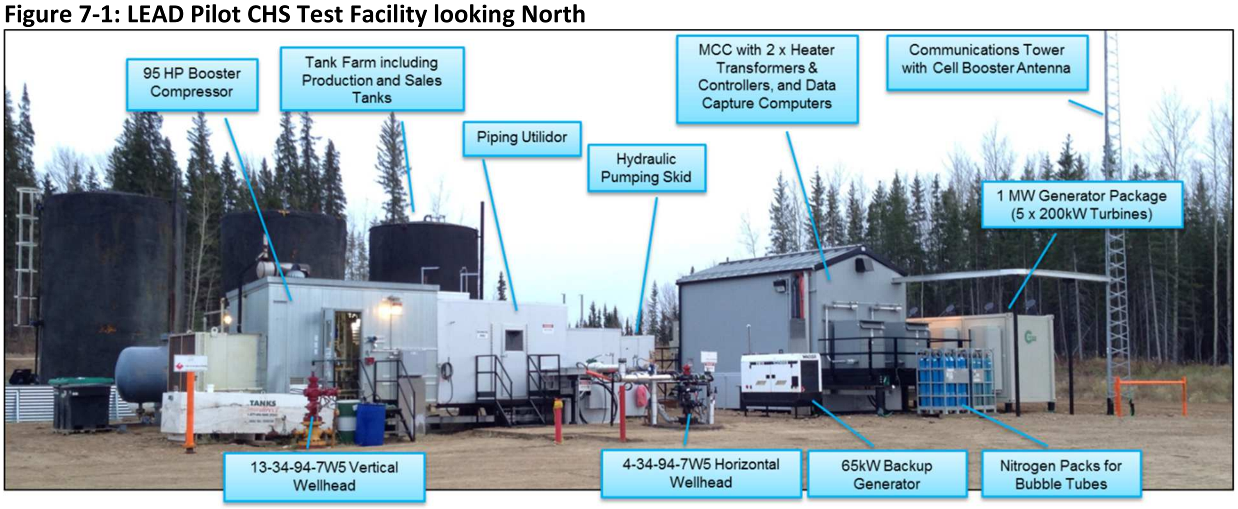


Figure 7-2: LEAD Pilot CHS Test Facility looking South

7.2 Capacity Limitation, Operational Issues, and Equipment Integrity

Production was limited by the pump stroke settings and reservoir inflow. The facility operation was also limited by the power generation and corresponding downhole electrical heating. During the heating phase, hot spots (limited to 270 deg C to protect the DTS) limited energy input to the reservoir, as the average lateral temperatures were significantly less than the maximum temperatures.

Table 7-1: Operation and Equipment Integrity

Date	Event
Dec 14, 2015	Bubble tube computing wrong pressures.
Jan 11, 2016	Bubble tube issue resolved. Installed heater fan to provide heat to the panel.
Jan 22, 2016	Heating and fall off; attempting to collapse hot spot.
Jan 30, 2016	Thyristor 1 fused blew. Heater tripped on high temp, heater automatically ramped down.
Feb 21, 2016	Heaters were turned off; end of cycle 1 heating.
Feb 24, 2016	Well bled down slowly to prevent overheating of ESP-MI splice.
Feb 25, 2016	Pump installed.
Feb 26, 2016	Pump was unseating on each stroke due to thick bitumen seizing the pump.
Feb 29, 2016	Pump pulled for inspection and was rebuilt.
Mar 01, 2016	Tubing and casing flushed with hot oil; pump installed.
Mar 02, 2016	Pump started at 230 bbl/d.
Mar 07, 2016	Heater @ 150 KW for flow assurance.
Mar 14, 2016	Heater @ 160 KW.
Mar 21, 2016	Heater @ 180 KW.
Apr 14, 2016	Heater off. Attempt to produce with no heat addition.
Apr 15, 2016	Pump quit working. Stop pump and observe temperature fall-off.
April 29, 2016	End of fall-off; start of Cycle 2 heating.
May 01, 2016	Observe similar hot spots.
Jun 21, 2016	Start Cycle 2 production.
Jul 04, 2016	Heater 1 @ 280 KW. Pentair on site to troubleshoot heater 2.
Jul 11, 2016	Bubble tube controller causing communication issue.
Aug 08, 2016	Storm pushed pump stroking unit sensor out of alignment; pump went down.
Sep 08, 2016	Heater 2 converted to single phase.
Sep 19, 2016	Capstone Turbine B anomaly.
Oct 08, 2016	Heaters turned down to collapse hot spots.
Oct 13, 2016	End of Cycle 2 production. Start of Cycle 3 Solvent injection.
Oct 14, 2016	Cycle 3 Heating @ 200 kW.
Oct 17, 2016	Heater 1 firing board problem. Heater 2 firing board installed in heater 1. Power @ 252 KW.
Oct 26, 2016	Start of Cycle 3 production.
Oct 31, 2016	Pump went down; end of Cycle 3 production.
Nov 06, 2016	Pump rebuilt and installed.
Nov 10, 2016	No production.
Nov 11, 2016	Heater 1 went down.
Nov 14, 2016	One leg of heater failed; converted to single phase.
Nov 15, 2016	Asphaltene debris in pump. Toluene @ 100 Deg C dissolves debris rapidly. Heater @ 225 KW.
Nov 29, 2016	Toluene clean out. Cycle 4 heating. Soak @ 120 deg C.
Dec 05, 2016	Start of Cycle 4 production with heater @ 240 KW.
Jan 06, 2017	Heater power @ 125 KW.
May 02, 2017	Heater off.
May 05, 2017	Well shut-in.
May 31, 2017	End of project.

7.3 Process Flow and Site Diagram

A facility process flow diagram can be found in Appendix A.

8 Environmental / Safety / Regulatory Compliance

8.1 Environment & Safety

No environmental or safety issues arose during the project.

8.2 Regulatory Status & Compliance

Project regulatory submissions and approvals are summarized as follows:

- **Experimental Recovery Scheme Approval**
  - July 24, 2014: Obtained Experimental Scheme Approval No. 12283 (for Full LEAD Pilot design)
  - January 26, 2015: Obtained Experimental Scheme Approval Amendment No. 12283A (Updated to split the Pilot into Stage 1 and Stage 2)
  - September 28, 2016: Obtained Experimental Scheme Approval Amendment No. 12283B (Updated to allow C5+ solvent injection)
- **EPEA**
  - June 2, 2014: Obtained AER EPEA Approval No. 299681-00-00
  - September 29, 2014: Received a 'No Objection Letter' from the AER for LEAD Pilot Stage 1 design
  - February 2, 2015: Groundwater Monitoring Program Proposal approved by AER
- **Facility License**
  - Facility is considered a Single Well Bitumen Battery, and therefore requires no facility license
- **Injection Well Approval**
  - August 5, 2015: Obtained D51 Class IV Injection Well Approval for 100/04-34-094-07W5 horizontal well (a condition of the Experimental Scheme Approval for heater operation)

This project fully complied with all regulatory requirements.

8.3 Plan for Shut-Down and Environmental Clean-up

The Panny LEAD Pilot Project (Panny) has been operated under Environmental Protection and Enhancement Act (EPEA) Approval No. 299681. The EPEA Approval will expire on April 30, 2020.

Perpetual will submit a Decommissioning and Land Reclamation Plan as per Condition 15 of Schedule IX of the Approval six months prior to the expiry date. The EPEA approval will then revert to a decommissioning and land reclamation approval and will remain active until reclamation certificates are issued.

Perpetual is conducting third-party ground water testing on an annual basis and submitting the data to the regulator.

9 Summary Operating Plan

9.1 Actual Project Schedule including Deliverables and Milestones

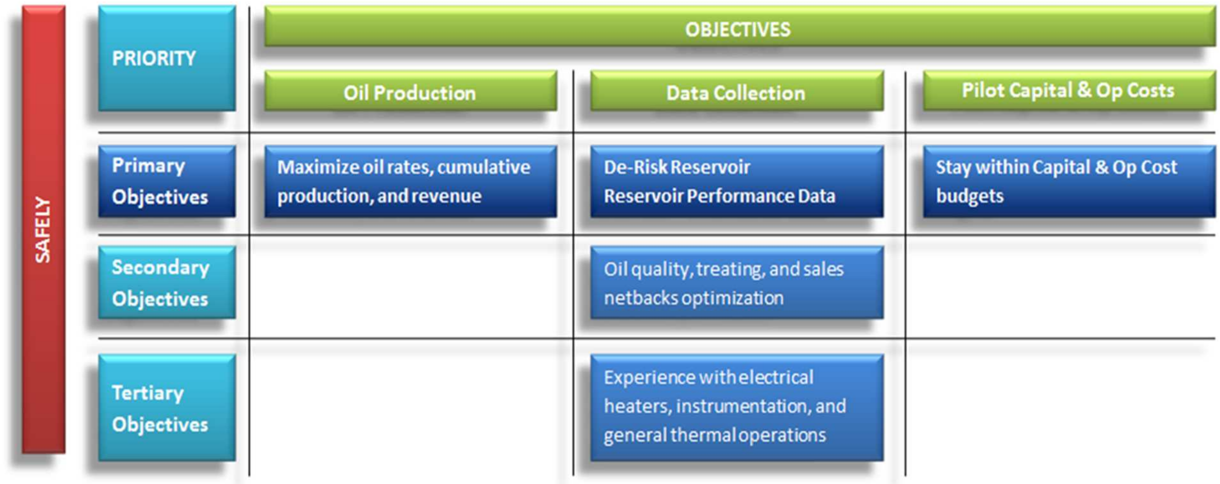


Figure 9-1: Original Objectives of the Pilot

Table 9-1: Original Schedule and Milestones

	2014								2015											
Activity	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Winter Access (~Dec 15 - Mar 15)																				
Detailed Engineering																				
Long Leads Procurement																				
Facility Construction																				
Drill Wells (3 Obs & 2 Hz)																				
Complete Wells																				
Warm-up (up to 6 mths)												First Heat								
Production																	First Production			
Stakeholder Consultation																				

Original project deliverables:

- Daily heat input to the horizontal well.
- Daily temperatures, pressures at the horizontal well and the observation wells.
- Daily bitumen, water and gas rates from the horizontal well.
- Data analysis determining heat distribution and pressure response.
- Data analysis determining development of the heat chamber/production envelope.
- Data analysis aiding in understanding how heat is distributed with the addition of water and/or diluent.

Table 9-2: Actual Project Milestones Log

Date	Event
Feb 24, 2015	Rig released PEOC Panny 12-34-94-7W5 observation well
Mar 3, 2015	Rig released PEOC Panny 6-34-94-7W5 observation well
May 6, 2015	Completed fuel gas pipeline from 8-33-94-7W5 to Pilot site 13-34-94-7W5
Jul 17, 2015	Installed downhole electrical heater and instrumentation in 4-34-94-7W5
Oct 13, 2015	Construction & commissioning completed on the Pilot facility at 13-34-94-7W5
Oct 15, 2015	Operations start-up including ‘first heat’ from the downhole electrical heaters
Feb 25, 2016	Pump installed
Mar 02, 2016	First Production
April 29, 2016	Cycle 2 heating
Jun 21, 2016	Cycle 2 production with heating
Oct 13, 2016	Cycle 3 solvent injection
Oct 26, 2016	Start of Cycle 3 production
Nov 29, 2016	Toluene clean out, start of Cycle 4 heating
Dec 05, 2016	Cycle 4 production with heating
May 02, 2017	Heater off
May 05, 2017	Well shut-in
May 31, 2017	End of project

The Pilot was terminated May 06, 2017 after downhole failure of the second heater. Perpetual continues to gather pressure and temperature data at the observation wells.

Solvent research and modeling are currently underway to identify a technically and economically optimum solvent mixture for future testing in the reservoir. This research and modeling is expected to form the basis for a Phase 2 project potentially including laboratory simulation and a field Pilot.

The key project deliverables and objectives as finally approved were achieved, including but not limited to:

- Concurrent production of bitumen and the gas cap.
- Maximized production through optimized pump operation.
- Oil treatment on location to sales quality without use of diluent (maximizing netback).
- Extensive data collection to de-risk reservoir and refine coupled heating / production models.
- Experience in heater installation, operation and thermal enhancement of reservoir.

10 Interpretations and Conclusions

10.1 Assessment of the Overall Performance of the Pilot

10.1.1 Lesson Learned

The LEAD Pilot project performed well by most measures. Significant knowledge was gained regarding downhole electrical heater operation, reservoir properties, and production characteristics while simultaneously heating. Trial solvent injection resulted in loss of deliverability due to the formation of Asphaltenes, and Toluene injection successfully restored deliverability.

The gyro log run in the 100/04-34-094-07W5 well at the outset of the project was significant in identifying that the wellbore was consistently 2.0° off of the original MWD drilling survey, which equated to the toe of the well being 36m east of where it was initially believed to be. This was an important finding in order to properly plan the observation wells and to assure landing them within 3-4m of the 100/04-34 horizontal. The source of this directional variance may be a local magnetic anomaly.

The project demonstrated the following:

- Feasibility of reducing viscosity of bitumen within the Bluesky formation through the use of electric cable(s).
- Feasibility of concurrent production of an associated gas zone with the production of underlying bitumen. Vertical transmission of heat in the reservoir resulted in communication with the gas cap, however, this did not impede continued production
- Lateral and vertical heat conduction characteristics within the reservoir.
- Potential for commercial production, with indication of expected ultimate technical recovery factor.
- Feasibility of numerically simulating the coupled heating / production process and variants of the process to enable commercial optimization.
- Significance of allowing slight reduction to irreducible water in reservoir models with electrically generated heating.
- Degree to which solvent (C5 + C6) instigated asphaltene deposition in Bluesky heavy oil.
- Ability of Toluene at 100 deg C to rapidly dissolve asphaltenes and restore well deliverability.
- History matching of pressure in a coupled heating / production reservoir model presents significant challenges.
- Hotspots developed in a horizontal wellbore with electric heating correlate significantly with high points along the undulating wellbore trajectory, and may relate to convective effects.
- Production of thermally mobilized bitumen from the upper layers of the reservoir suggests that mud drapes identified in core have limited or discontinuous aerial extent.
- Economic viability associated with electric heating remains challenged in the current commodity pricing environment.
- Reliability and life of heaters not acceptable for commercial application, however, this technology continues to advance and what appear to be superior heaters are now available.

10.1.2 Difficulties Encountered

A number of challenges were encountered through the course of the LEAD Pilot:

- Circulation was lost while drilling 102/12-34-094-07W5 and 100/06-034-094-07W5 through the Paleozoic. Future drilling would terminate above the Paleozoic.
- Difficulties were encountered pumping oil with the heaters turned off after the first heating cycle. Produced oil temperatures dropped quickly with a corresponding increase in viscosity, and the oil could not be pumped. The heater was turned back on at low power to help resolve the issue, and production was restored to 36 m3/d (declining thereafter). This was the impetus for the discovery that simultaneous heating and production of the reservoir is viable and preferable.
- Established oil deliverability was lost suddenly after a solvent injection test later in the Pilot, due to unanticipated asphaltene precipitation. Subsequent lab studies were undertaken, and determined that toluene at 100 deg C would rapidly dissolve the asphaltenes. A toluene treatment with heat at a wellbore temperature of 120 deg C successfully restored the well deliverability. Additional studies are now being pursued to identify optimum solvents and/or asphaltene stabilizers to maintain asphaltenes in solution.
- Electrical continuity of the heater cables was progressively lost through the course of the Pilot, resulting in reduced energy input and production rates. While the heater cables have not yet been recovered from the wellbore, it is believed that splice failures are at fault. Heater cables reliability and ultimate failure constituted the major disappointment of the Pilot, although the resultant step changes in heat rates through the course of the project yielded additional transient data of technical value.

10.1.3 Technical and Economic Viability

Without heat the 100/04-034-094-07W5 well was not capable of sustaining production greater than ~0.5 m3/d. The LEAD Pilot demonstrated the viability of in-situ electric heating to reduce oil viscosity, and to sustain early oil production proportional to energy input.

The project also demonstrated concurrent gas cap gas production and thermally assisted oil production. Horizontal wells equipped with electric heater technology drilled at desired length and spacing can technically be used to exploit a low-mobility bitumen reservoir. The LEAD Pilot produced over 1,900 m^3 (12,000 bbls) of oil, and would have produced more in the absence of heater failures.

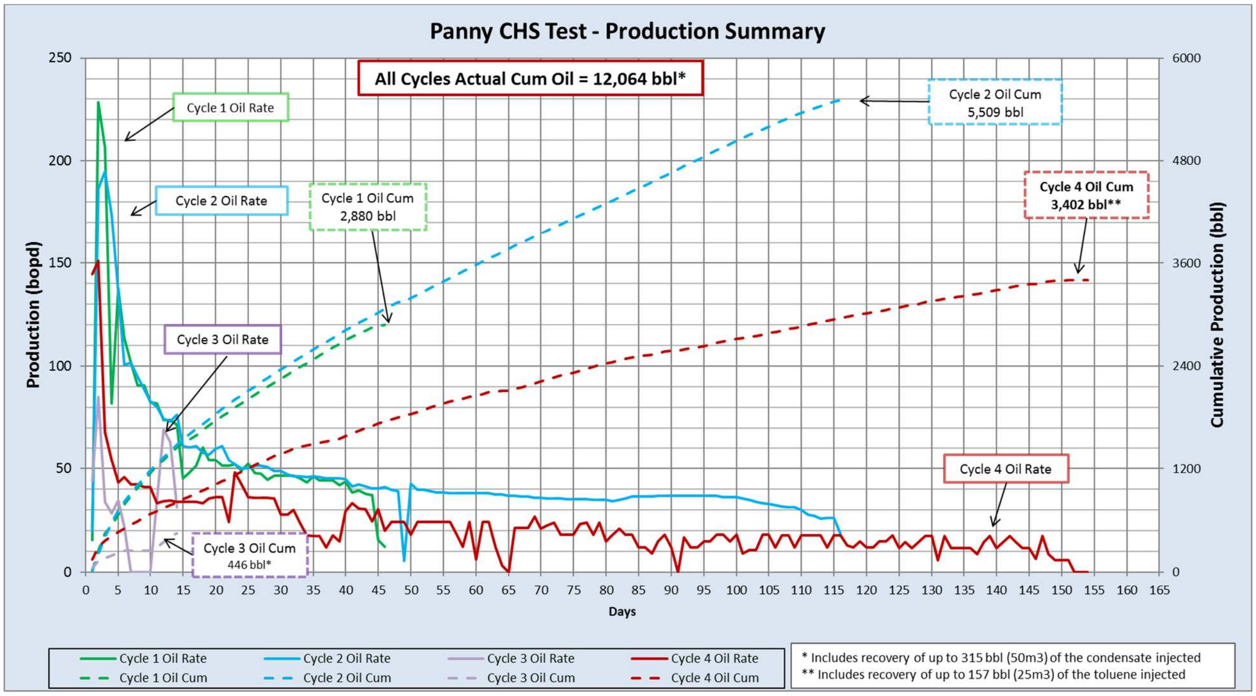


Figure 10-1: 100/04-034-094-07W5 LEAD Pilot Oil Production

Electric heating is not economically viable in the LEAD Pilot reservoir at current commodity pricing. However, based on the coupled heating / production models developed through the LEAD Pilot, the technology appears much closer to being economically viable in bitumen reservoirs with moderately higher mobility (lower viscosity and/or higher permeability parameters), and a second-generation electric heating Pilot with improved hardware in an alternative reservoir is presently being planned. Alternatively, the technology can potentially be combined with other recovery methods and/or as a secondary or tertiary mechanism to yield economic incremental reserves. Studies are underway, for example, to combine hot solvent injection with low pressure electrothermal heating to effect a combination of conductive and convective thermal energy delivery and reflux to efficiently capture heavy oil or bitumen reserves.

With the emergence of higher power density cables, electric heater cables can be used for SAGD reservoir preheating while surface facilities are being constructed, accelerating first oil production following completion of the facilities.

Limited heater cable options were available at the start of the LEAD Pilot. The risk of cable failure at hot-hot splices and cold-hot splices was known and discussed. However, the heater failed prematurely despite attempts to mitigate known risks, and failures of this nature obviously impact the risked economic viability of the technology. Splice-less heater technology is now been marketed, and in theory enables longer lengths, higher energy delivery, and significant operating life. However, the cost of electricity remains a significant potential barrier to economic recovery of reserves. “Behind the fence” power generation using natural gas may reduce life cycle power costs relative to the commercial grid, particularly in more remote locations.

Finally, significant heavy oil reserves exist in Alberta that cannot be economically produced using Cyclic Steam Stimulation (CSS) or Steam Assisted Gravity Drainage (SAGD) due to presence of low-pressure gas caps, bottom water, shallow depth with low-integrity cap rock, or thin pay. Downhole electric heaters provide a feasible means of exploiting these otherwise stranded reserves by uniformly heating and mobilizing the oil at low pressures.

10.1.4 Assessment of Future Expansion or Commercial Field Application

The LEAD Pilot project was originally conceptualized in two stages.

LEAD Pilot Stage 1: Cyclic Heating Stimulation (CHS) Test

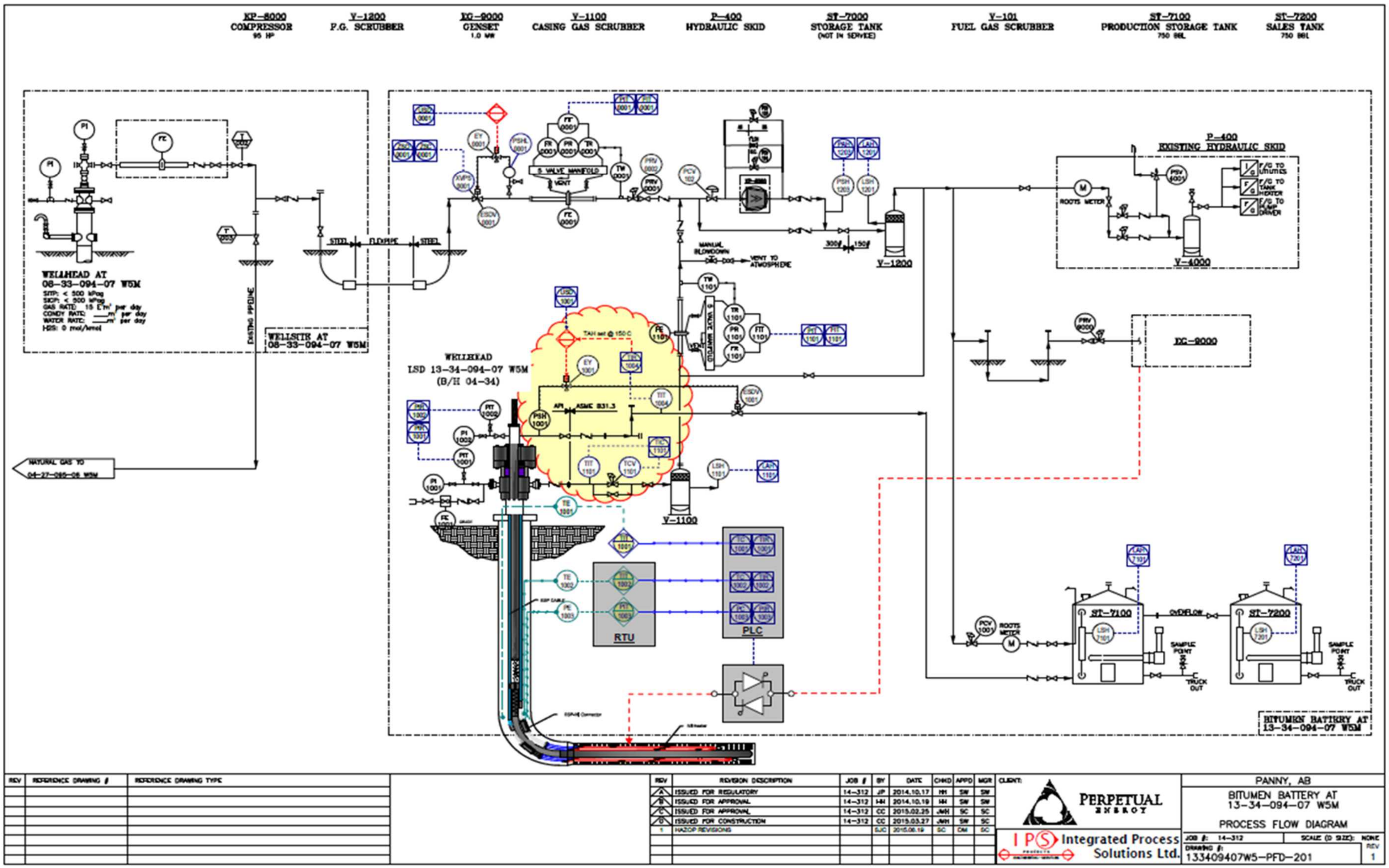
- Single horizontal well;
- Lower output heaters (~600W/m);
- Cycle between heating reservoir for 3-6mths, then producing for ~1mth; repeat;
- Possibly inject water or solvent in later cycles.

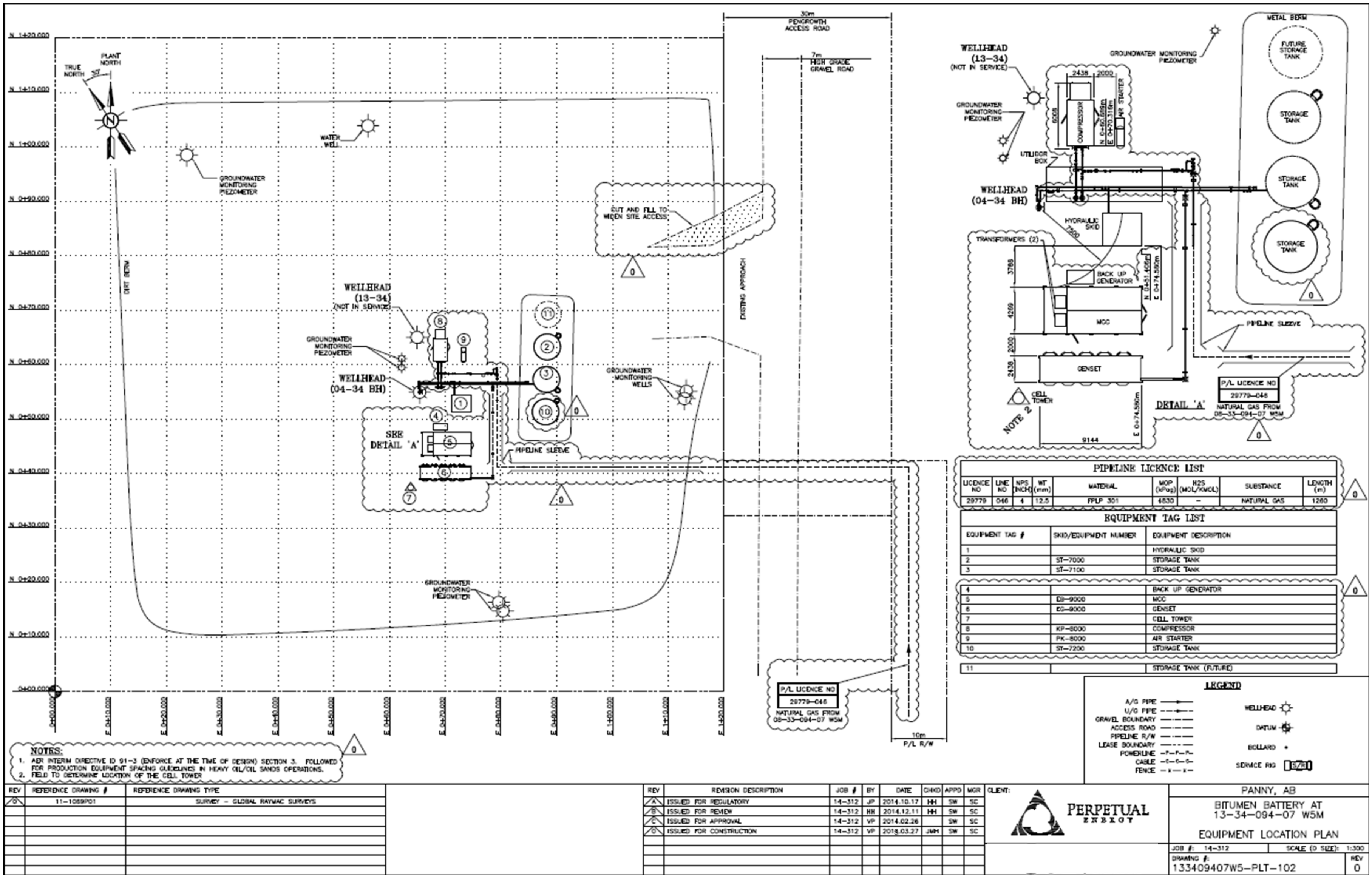
LEAD Pilot Stage 2: Full LEAD Pilot (future)

- Horizontal 'well pairs' – heater/injector above, producer below;
- High output (~1000W/m) heaters required;
- Hot water/solvent injection to move heat into the reservoir and 'drive' the oil to the producer; continuous process.

Once splice-less heater technology has been proven, the availability of reliable high-power output heaters will facilitate pursuit of the LEAD Pilot Stage 2. This second phase of the Pilot will explore conductive and convective heat transfer phenomena against the conductive benchmark established in Stage 1. Conductive heat transfer relies solely on the thermal conductivity of the rock fabric which is relatively slow heat transfer. However convective heat transfer utilizes a thermal transport medium like water to effect, more efficient, distributed heating of the reservoir, promoting accelerated production and improved economics.

Appendix A: Facility Process Flow Diagram





PIPELINE LICENCE LIST

LICENCE NO	LINE NO	NPS (INCH)	WT (mm)	MATERIAL	MOP (kPag)	H2S (MOL/KMOL)	SUBSTANCE	LENGTH (m)
29779	046	4	12.5	FPLP 301	4830	–	NATURAL GAS	1260

EQUIPMENT TAG LIST

EQUIPMENT TAG #	SKID/EQUIPMENT NUMBER	EQUIPMENT DESCRIPTION
1		HYDRAULIC SKID
2	ST-7000	STORAGE TANK
3	ST-7100	STORAGE TANK
4		BACK UP GENERATOR
5	EB-9000	MCC
6	EG-9000	GENSET
7		CELL TOWER
8	KP-8000	COMPRESSOR
9	PK-8000	AIR STARTER
10	ST-7200	STORAGE TANK
11		STORAGE TANK (FUTURE)

REV	REVISION DESCRIPTION	JOB #	BY	DATE	CHKD	APPD	MGR
A	ISSUED FOR REGULATORY	14-312	JP	2014.10.17	HH	SW	SC
B	ISSUED FOR REVIEW	14-312	HH	2014.12.11	HH	SW	SC
C	ISSUED FOR APPROVAL	14-312	VP	2014.02.26		SW	SC
0	ISSUED FOR CONSTRUCTION	14-312	VP	2018.03.27	JMH	SW	SC