IETP Application No. 06-094

Imperial Oil Resources – Cyclic Solvent Process Pilot

2018 Final Project Technical Report

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1 Abstract

Imperial Oil Resources (Imperial) is conducting a Cyclic Solvent Process (CSP) experimental pilot scheme at Cold Lake in the Clearwater formation and it is being operated under Energy Resources Conservation Board (ERCB) Approval 11604, dated May 5, 2011.

CSP is a non-thermal, in-situ bitumen recovery process that utilizes injected solvent to reduce the viscosity of the bitumen, enabling its production from the sub-surface. The liquid-phase solvent is injected into a horizontal well in a cyclic manner. The large mobility contrast between the solvent and the bitumen causes the solvent to finger into the bitumen creating the mechanical dispersion and large contact area for rapid mixing of solvent into the bitumen. Solvent injection volumes will grow with each cycle to ensure mixing with previously uncontacted bitumen.

Since CSP is a non-thermal process, the two key challenges facing traditional thermal processes (e.g. Cyclic Steam Stimulation and Steam Assisted Gravity Drainage) are avoided: (1) thermal inefficiencies which limit applicability to thinner and/or lower bitumen saturation reservoirs and (2) the production of GHGs arising from burning natural gas to produce steam.

The pilot is located at K50 pad in Imperial's Cold Lake development and is being conducted in the Clearwater formation. Three short horizontal wells are operated using CSP as a recovery process. This final report summarizes project progress through the IETP reporting period.

The overall goals of the pilot were achieved during the IETP reporting period. High quality data was obtained to allow definitive interpretation of the pilot results. Sufficient learnings were obtained to assess the commercial viability of CSP. Lastly, necessary operational experience with the process was obtained to enable cost-effective deployment of the technology. CSP technology has been deemed commercially viable through Imperial's internal technology development system.

2 Summary and Project Status Report

2.1 Members of the Project Team

The following are or were previously the key members of the CSP pilot team from project inception to end of 2018.

Name	Title
C. (Cheryl) Trudell, PhD, P.Eng.	Research Vice-President
M. (Mark) Beckman, PhD, P. Eng.	HO In-situ Research Manager
J. (Jianlin) Wang, PhD	CSP Team Lead
G. (Gordon) MacIsaac, PhD	CSP Reservoir Engineer
M. (Mat) Suitor, P.Eng.	CSP Reservoir Engineer
L. (Lu) Dong, M.S.	CSP Reservoir Engineer
N. (Nafiseh) Dadgostar, PhD	CSP Reservoir Engineer
M. (Mike) Sheptycki, P.Eng.	CSP Project Manager
J.F. (John) Elliott, P.Eng.	Oil Sands Recovery Research Manager
T.J. (Tom) Boone, PhD, P.Eng.	ExxonMobil Senior Technical Professional
D.E. (Dave) Courtnage, P.Eng.	CSP Team Lead
M. (Mori) Kwan, PhD, P.Eng.	CSP Pilot Lead
A.J. (Andrew) Hodgetts, P.Eng.	Projects Manager Brownfield/Research
V. (Vera) Ivosevic, P.Eng.	CSP Project Manager
J. (Jason) Klassen	CSP Operations Specialist
K. (Keith) Machatis	CSP Operator
B. (Barry) McLaughlin	CSP Operations Specialist
B. (Brett) Garrison	CSP Operations Specialist
T. (Tulegen) Ibrayev	CSP Operations Specialist
J. (Jeremy) Newton	CSP Operator
R. (Ryan) McNabb	CSP Operator
S. (Shane) Derlukewich	CSP Operator
J. (Duane) Jones	Measurement Coordinator
E. (Ernest) Han	Laboratory Technologist
R. (Rui) Wang	Laboratory Technologist
G. (Gerry Miller)	Laboratory Technologist
L. (Lori) Schmidt	Laboratory Technologist

2.2 Key Activities

Key activities and operations conducted over the project reporting period (2012 through 2018) are listed in the following section. Activities are categorized as facility construction and maintenance, well specific items or facility-wide items. Under each category the events are listed chronologically. The three horizontal wells are referenced throughout the document as HW1, HW2 and HW3. For reference, the key activities are also shown in Figures 1 and 2.

2.2.1 Pad Facility Maintenance and Construction Activities

2012

- Drilling and completion of the horizontal wells
- Execution of the initial cross-well seismic survey
- Completion of detailed facilities design
- Initiation of construction activities

2013

- Horizontal well completions
- Completion of surface facility construction

2014

- Facility pre-commissioning from February to the end of April
- Facility was turned over to Cold Lake Operations with final commissioning completed by the end of May
- First injection and production from HW3; injection system controls and diluent quality issues requiring troubleshooting
- Hydrate formation in the trunkline to Mahihkan plant during initial production
- The pipeline hydrates were removed, additional hydrate and phase behavior studies were conducted, and new operational guidelines were adopted to prevent future occurrences
- The CSP pad was shut-in for the remainder of the year while the team worked to implement resolutions to the flow issues

2015

- Trunkline hydro-test in June to increase the Maximum Operating Pressure (MOP) from 1850 to 3675 [kPa]

2016

- Compressor skid and wellhead flow assurance solvent manifold installation from January 1 to 29
- Test separator demulsifying chemical injection skid installation from March 20 to 24

- Test separator oil-leg extension pipe installation for improved separation efficiency from October 8 to October 27

2017

- No notable maintenance or construction work during this year
- Pipeline unplugging activities from December 25 through year-end

2018

- Pipeline unplugging activities from December 25, 2017 to January 9
- Pipeline unplugging activities from April 12 to June 13
- Planned pipeline integrity inspection work between July 17 and September 27

2.2.2 HW1 Activities

2016

- HW1 cycle 1 injection from February 5 to 9, production from February 12 to March 31
- HW1 cycle 2 injection from April 10 to 15, production from April 17 to July 6
- HW1 cycle 3 injection from July 12 to 21, production from July 22 and continued through year-end
- Casing pressure control valve installation from October 5 to 13
- HW1 pump replacement from December 1 to December 5

2017

- HW1 cycle 3 production continued to January 16, followed by a pump replacement
- HW1 cycle 4 injection from January 24 to February 7
- HW1 cycle 4 production from February 10 to November 20
- HW1 pump replacements in October and November
- HW1 cycle 5 injection from November 21 to December 10
- HW1 cycle 5 production from December 11 through year-end 2017

2018

- HW1 cycle 5 shut-in between December 25, 2017 to January 9 due to pipeline plugging
- HW1 cycle 5 production from January 9 to March 21
- HW1 shut-in for pressure build up from March 21 to April 3
- HW1 cycle 5 production from April 3 to April 12
- HW1 cycle 5 shut in between April 12 to June 13 due to pipeline plugging
- HW1 cycle 5 shut in between June 13 to July 17 due to pipeline limitations
- HW1 cycle 5 shut in between July 17 to October 22 due to pipeline cleaning and integrity work

- HW1 cycle 5 production between October 22 and continued through end of 2018

2.2.3 *HW2 Activities*

2014

- Remainder of completion work on HW2 and HW3 completed in early February

2015

- No notable HW2 events in this year

2016

- HW2 cycle 1 injection from May 5 to 9, production from May 11 to June 30
- HW2 cycle 2 injection from July 6 to 10, production from July 13 to Sept 18
- HW2 Casing pressure control valve installation from September 20 to 22
- HW2 cycle 3 injection from September 25 to October 10, production from October 4 and continued through year-end

2017

- HW2 cycle 3 production continued to March 17
- HW2 cycle 4 injection from March 21 to April 3
- HW2 cycle 4 production from April 5 into 2018
- HW2 pump replacement on April 19

2018

- HW2 cycle 4 shut in between December 25, 2017 to January 9, 2018 due to pipeline plugging
- HW2 cycle 4 production from January 9 to March 1
- HW2 cycle 5 injection starts March 1 to March 24
- HW2 cycle 5 production from March 25 to April 12
- HW2 cycle 5 shut-in between April 12 to June 13 due to pipeline plugging
- HW2 cycle 5 shut-in between June 13 to July 17 due to pipeline limitations
- HW2 cycle 5 shut-in between July 17 to September 27 due to pipeline cleaning and integrity work
- HW2 cycle 5 production between September 27 and continued through end of 2018

2.2.4 *HW3 Activities*

2014

- Remainder of completion work on HW2 and HW3 finished in early February

- Cycle 1 injection from May 29 to June 8 with interruptions due to injection system controls and diluent quality issues
- Initial production lasted from June 10 to 12 but was halted due to hydrate formation in the trunkline to Mahihkan plant
- From mid-June to mid-August, the pipeline hydrates were removed, additional hydrate and phase behavior studies were conducted, and new operational guidelines were adopted to prevent future occurrences
- Production of cycle 1 resumed intermittently from mid-August to mid-September but was ultimately discontinued so that surface facility flow issues could be addressed
- During the August to September production, diluent was injected at times into the wellbore and near wellbore reservoir to clear it of blockage and stimulate production

2015

- Preparatory work for the restart of HW3 cycle 1 completed Q1 of 2015
- HW3 cycle 1 restarted on April 9
- HW3 cycle 1 production completed on June 8
- HW3 cycle 2 injection started on June 18 and completed on June 24.
- HW3 cycle 2 production progressed smoothly and completed September 4
- HW3 cycle 3 injection started on September 15 and completed on September 23.
- HW3 cycle 3 production began on September 25
- Cycle 3 shut-in on November 25 for wellhead heat-tracing installation and pilot site access bridge scheduled maintenance
- Cycle 3 production resumed on December 11 and shut-in on December 27 in preparation for facility upgrades in January of 2016

2016

- HW3 cycle 3 restarted on January 31 (after compressor skid installation), production continued to March 20
- HW3 cycle 4 injection from March 23 to April 4, production from April 6 to November 27
- HW3 cycle 5 injection from November 27 to December 17, production from December 19 and continued through year-end
- Casing pressure control valve installation from September 25 to October 3

2017

- HW3 cycle 5 continued through year-end 2017

2018

- HW3 cycle 5 shut in between December 25, 2017 to January 9, 2018 due to pipeline plugging

- HW3 cycle 5 production continued through March 21
- HW3 cycle 6 injection from March 22 through April 23
- HW3 cycle 6 production delayed from March 25 to June 13 due to pipeline plugging issues
- HW3 cycle 6 production from June 13 to July 17
- HW3 cycle 5 shut in between July 17 to October 1 due to pipeline cleaning and integrity work
- HW3 cycle 6 production between October 1 and continued through the end of 2018

2.2.5 Facility-wide Activities

- 4D seismic Monitor 1 shoot on December 18, 2016
- 4D seismic Monitor 2 shoot on February 8, 2017
- 4D seismic Monitor 3 shoot on December 10, 2017

2.3 Production, Material and Energy Balance

At the end of 2018 the CSP pilot had completed 13 cycles with HW1 and HW2 continuing to produce cycle 5 while HW3 was in cycle 6. There was 27,074 [m^3] of total solvent injected with varying amounts per well (HW1: 7,847 [m^3]; HW2: 7,454 [m^3]; HW3: 11,773 [m^3]). Total bitumen production was 11,406 m^3 with varying amounts per well (HW1: 3,594 m^3; HW2: 3,279 m^3; HW3: 4,533 m^3). The resulting oil-to-injected solvent ratio (OSR) is 0.42 and the total solvent recovery (SR) to end of 2018 was 55%. The cumulative metrics include production for the current ongoing cycles which were not completed by the end of the reporting period. Therefore, the stated metrics are lower than expected upon cycle completion.

Monthly injection and production volumes for the IETP reporting period are tabulated in the Tables section. Injection volumes for each well are shown in Tables 1 through 5. Total production volumes are shown in Tables 7 through 12 with per well volumes given in Tables 13 through 26. A summary of annual injection and production volumes are shown in Table 6 and 12, respectively.

The reported production volumes are engineering estimates based on a combination of pad test separator readings, density based calculations, and compositional analysis of physical samples collected during production. Since propane, flow assurance solvent and bitumen are present in the produced oil phase; the process for determining component volumes is much more challenging than for traditional steam based processes, in which bitumen is the only oil phase component.

In the initial project application submitted in 2011, production forecasts for the pilot were generated using 3D reservoir simulation models. These models indicate that for five injection cycles over three years, and a total injection of 14,400 [m^3] of solvent per well with corresponding production totaling 3900 [m^3] per well, yielding an oil-solvent ratio of 0.27. Solvent recovery was estimated at 90%. The pre-pilot flowstream is shown in Figure 3.

2.4 Resource

Based on a Petrel-based geologic model, the estimate of bitumen-in-place in the pilot area is 879 [km^3]. The total bitumen produced for completed cycles during the reporting period is 8.9 [km^3] with a total of 15.8 [km^3] solvent injection. The ratio of the produce bitumen relative to the bitumen-in-place is not representative of the recovery factor of a commercial development. The completed cycles of the pilot wells represent only a portion of the expected well life for a commercial project, which leads to lower recovery levels at the current reporting time. Additionally, the wells have been purposefully spaced farther apart in the pilot to avoid interaction, which is different than in a commercial project. The recovery factor of the base process without follow-up strategies is expected to be between 20-50% depending on a number of factors, such the well-spacing and cycle economics limits.

3 Well Layout and Geology

3.1 Well and pad layout

The pilot consists of six observation (OB) wells and three horizontal wells:

IMP 08 OV COLD LK 14-18-65-4	– UWI 1AA/14-18-065-04W4/00
IMP 10 CSP OB-1 LEMING 14-18-65-4	– UWI 105/14-18-065-04W4/00
IMP 10 CSP OB-2 LEMING 14-18-65-4	– UWI 100/14-18-065-04W4/00
IMP 10 CSP OB-3 LEMING 14-18-65-4	– UWI 102/14-18-065-04W4/00
IMP 10 CSP OB-4 LEMING 14-18-65-4	– UWI 103/14-18-065-04W4/00
IMP 10 CSP OB-5 LEMING 14-18-65-4	– UWI 104/14-18-065-04W4/00

IMP 11 CSP H-01 LEMING 3-19-65-4	– UWI 100/03-19-065-04W4/00
IMP 11 CSP H-02 LEMING 14-18-65-4	– UWI 110/04-18-065-04W4/00
IMP 11 CSP H-03 LEMING 14-18-65-4	– UWI 111/04-18-065-04W4/00

The layout of the wells is shown in Figure 4. The six OB wells were drilled from three pads and the three horizontal wells were drilled from a fourth pad. Surface facility and pad locations are shown in Figure 5.

Well 14-18 was drilled in 2009; the remaining five OB wells were drilled in 2011. The horizontal wells were drilled in March 2012. All wells were completed from late 2012 to early 2013.

3.2 Drilling, completion, and work-over operations

Figure 6 shows the OB wells surface and bottom-hole locations relative to the horizontal wells and identifies the specific instrumentation for each well. The HW completions are summarized in Table 27 and the OB well completions are summarized in Table 28.

The first well of the pilot area, namely OV well 14-18 was drilled in 2009. The purpose of the OV well was to delineate the resource and inform the selection of the pilot location.

Five additional observation wells were drilled in 2011. Completions began in late 2011 and were finished in early 2012. The five OB wells are equipped with passive seismic geophones, thermal fiber heaters, and pressure and temperature sensors, in various configurations as outlined in Table 29 to assist in monitoring the pilot.

The three pilot short horizontal wells were drilled in March 2012. All wells met their directional requirements. Final time was 27.7 days rig release to rig release, 21.0 days spud to rig release.

Surface holes of 17.5 [in] were drilled and 13.375 [in] surface casings were set at the depths indicated in Table 30. Surface casings were cemented in place. A wireline log was run on the first hole to confirm the depth of the Colorado Shale formation top. Casing was set 15 [m] into competent shale. Intermediate holes of 12.25 [in] were drilled to an angle of ninety degrees and a 9.625 [in] intermediate casing was set at the depths indicated in Table 30. The intermediate casing was cemented in place. A cement bond log was run prior to drilling out the lateral section.

Results of the cement bond logs are shown in Table 31. All three bond logs were satisfactory. All required zones were properly isolated. Cementing best practices were followed and required pump rates were obtained.

Lateral holes of 8.5 [in] were drilled with each section 110 [m] long. Slotted liners of 5.5 [in] were run into the lateral holes. There are five limited entry perforation screens per well. See Figure 7. One swell packer is run per well. Total depths of the wells are shown in Table 30.

Wireline retrievable bridge plugs were placed a minimum of 5 [m] below the Grand Rapids formation top in each well. Frac sand was placed on top of the plugs, with an approximate height of 2 to 2.5 [m], to secure the mandrel from any debris that might fall in the hole, pending the completions later in the fall.

Below is a summary of the horizontal well Completions design, shown in Figure 7:

- 7" casing string landed with a packer and expansion piece ~10 m above the top of the Clearwater formation. Casing string is necessary to complete annular isolation tests as part of the regulatory requirement for hydrocarbon injection-class wellbores.
- ~125 m long, 5" OD horizontal wellbore liner at bottom of well. Liner has 5 inflow control devices in place.
- Downhole heater: provides heat to the well liner region if necessary to reduce viscosity and improve flow capabilities.
- 12-Thermocouple bundle: takes temperature reading at specific points. Set points are primarily at the wellbore liner inflow control devices. Thermocouples are set as close as possible to target based on tubing tag and trip precision.
- ERD (electronic resonating diaphragm) dual sensor, connected into tubing mandrel. Precision pressure and temperature monitoring at single set point 5 m above the top of the horizontal wellbore liner.
- Two Bubble Tubes. Bubble tube #1 landed near toe of horizontal liner; Bubble tube #2 at rod insert pump seating depth. Pressure monitoring system tied into nitrogen skid at surface.
- ~120 clamps of 14 separate designs used to secure and protect all lines across the length of the wellbore tubing string

The first phase of horizontal well completions work occurred between September 2012 and March 2013. The design scope for the CSP horizontal wells involved setting a packer string for annular pressure monitoring, and deploying a tubing string with multiple instrumentation cables clamped to its exterior.

Installing the annular packers proved challenging as the initial packer installation procedure did not fully achieve a pressure seal. Modifications were made to the packer unit and procedures to capture and apply additional setting force. This primary packer model was subsequently successfully installed in HW1 and HW2. Difficulties remained in setting the primary packer model in the final horizontal well. A different packer system was sourced and fully installed in two stages; the packer element in February 2013, and a seal and expansion joint stinger in July 2013. All three annular packer systems were installed successfully.

Installation of the tubing string with attached thermocouples, heater, ERD sensor, and bubble tubes began in January 2013. The installation was completed successfully with full function tests on HW1. At HW2 all tubing and equipment was placed at the final setting position; at this point the final heater function test was not successful and the equipment was retrieved to surface. The primary finding was that one of the electrical connections necessary to splice the downhole heater unit to the well power cable suffered some water seepage, which was sufficient to foul the heater. As completions ran out of its allocated time in 2013, installation of instrumented tubing strings in HW2 and HW3 was rescheduled to Q1 2014.

The second phase of the horizontal well completions commenced in January 2014. The objective was to complete the tubing and instrumentation installation activities at HW2 and HW3 in order to finalize the wellbores for pilot operations.

Primary activities at HW2 occurred during January 10 to January 20. Initial steps included a mobilization and setup stage of all unique services to the CSP operation, drifting and scraping the well, and circulating the well clean with fresh water. The instrument lines (downhole heater, thermocouple bundle, bubble tubes, ERC sensor, as shown in Figure 7) were strapped and clamped to the tubing string exterior in order to land the equipment inside the well at precise pre-determined positions as has been the process consistently throughout the project; and the heater was checked every 50 [m] into the well as the recommended procedure. All the tests were reading maximum response in resistivity and conductivity prior to reaching the position, where the bottom of the tubing / heater string was situated just above the top of the 5.5 [in] LEP liner string (depth ~630 [mKB]). The resistivity test failure and successful conductivity test indicate that the source of the problem is likely seepage/fluid damage wetting the magnesium powder insulation, which implies that the heater lines are not physically broken. All other lines (bubble tubes, ERD sensor, and thermocouple) are functioning as normal on their latest tests, further indicating this is likely not cracking / pinch / scrape damage. The collective decision was made to complete the installation with the functionality loss in the heater unit to preserve all other well instrumentation. The tubing was landed on position and the wellhead installed on January 20.

Operations moved immediately to HW3 for mobilization efficiency. The overall scope of the operations plan was the same as HW2, including the scraper, drift, and fresh water circulation. Instrumentation clamping and installation proceeded as planned. Near the bottom of the well, a hang-up point was observed where the tubing string took weight indicating the pipe may potentially be dragging or shouldering slightly. After a team technical review, carefully lowering the tubing allowed passage past the tight point without any complications. All instruments were installed on target depth with full functionality.

Downhole rod insert pumps were installed on all three horizontal wells by early February after all surface facilities and pump jack installations were complete, putting the final equipment in place for upcoming production pumping operations. Pumps were left in bypass position to allow flow down the tubing strings for the first propane injection cycle. The OB well completions are summarized in Table 28 and HW completions are summarized in Table 27.

3.3 Well operation

2014

HW3 began injection on May 29 and continued to June 8. Injection was initially intermittent in order troubleshoot the issues with the injection control loop as well as plugging of diluent injection filters. Production from HW3 occurred intermittently from June 10 to 12 and from mid-August to mid-September. Interruptions were due to facility plugging caused by a single hydrate issue and then later by heavy hydrocarbon liquid phase formation.

The pilot was shut-in from September 2014 until April 2015 due to the surface facility challenges encountered in 2014.

2015

HW3 cycle 1 production was restarted on April 8 following a wellbore treatment with the flow assurance solvent. Production continued until June 8, 2015. The introduction of the flow assurance solvent resulted in a step change in facility performance. However, the pipeline differential was still a significant bottleneck for future operations. Gas production through the pipeline was limited to impractically low flow rates and future multi-well operation would not be possible. The pipeline was re-rated from an MOP of 1850 to 3675 [kPa] and was successfully hydro-tested prior to cycle 2 injection on June 18, 2015.

Cycle 2 injection achieved the target volume; however, the rate was limited by partial plugging of the ICDs. Production of cycle 2 was smooth with no reservoir issues encountered and continued until September 4, 2015.

Prior to cycle 3 injection the wellbore was treated with the flow assurance solvent to prevent the ICD plugging observed during cycle 2 injection. The treatment was successful. Cycle 3 injection was smooth with minimum pressure drop observed across the completions. The target injection rate and total injection volume was achieved. Production commenced on September 25, 2015 and continued uninterrupted until October 18, 2015 at which point production was shut-in for a two-day planned pressure build-up test. Thereafter, production continued until November 25, 2015. The pilot was shut-in to accommodate repairs to an access bridge. Wellhead heat-tracing was also installed during this shut-in. Production resumed on December 11, 2015 and continued until December 26, 2015. The pilot was shut-in at this point for the facility upgrades in January of 2016.

2016

The pilot was shut-in during January of 2016 for facility modifications, which included the installation of a compressor skid. Details of the modifications are given in Section 7.3. In 2016, multi-well operation was initiated with HW1 and HW2 coming online. HW3 continued with normal operation. Minor differences in the well operation strategy are discussed below.

HW3 cycle 3 was restarted in January 31. Lower pressure operation was attempted by venting the casing gas through the newly installed compressor package. The gradual reduction of BHP led to a significant increase in the water production, with limited benefit to the hydrocarbon production. In general, HW3 water production through cycles 1 and 2 was higher than the nominal pre-pilot expectations and therefore the observed increase in water production at lower pressures was anticipated. Consequently, the lower pressure operation for HW3 was generally avoided other than a planned test of sustained lower pressure during the late-stage of cycle 4.

HW1 was brought online to test the repeatability of the CSP process. The operational plan for injection and production of HW1 was the same as HW3. However, observed changes in the production performance led to changes in the late cycle operation. Specifically, the water production of HW1 was lower compared to HW3, thereby permitting low pressure late cycle operation.

HW2 was brought online to test two changes to the operational strategy. The injected solvent was changed to 100% propane to test the effects of removing the flow assurance solvent as a co-injectant. Furthermore, HW2 is not equipped with functioning downhole heaters, thus operating HW2 would naturally test the robustness of the process without downhole heating. For reference, HW1 and HW3 have active wellbore heaters set at 18 and 30°C, respectively.

2017

The pilot continued with normal multi-well operation in 2017. The operational strategies applied to each well are described below.

HW1 cycle 3 was completed in January 2017. Low wellhead pressures over the tail of production indicated a pump sealing issue. Prior to starting cycle 4 the pump was replaced. Cycle 4 injection was completed thereafter with the propane only injection. Previous cycles had followed a propane and flow assurance solvent co-injection strategy. However, the success demonstrated by HW2 with propane only injection led to a shift in strategy for HW1. Cycle 4 production began in February 2017 and continued to completion by November. Pump sealing issues re-occurred over the tail of production, eventually leading to a new anchor-style pump being landed above the PSN (pump seating nipple). HW1 cycle 5 injection was completed successfully and production began in mid-December before being shut-in due to pipeline plugging. Further details regarding the plugging event are described in Section 4.1.1.

HW2 cycle 3 was completed in March 2017. Propane only injection strategy continued for this well. Cycle 4 injection began in March with production starting thereafter in April. Production rates were initially below normal due to poor pump performance. The seized pump was replaced and normal production resumed thereafter.

HW3 cycle 5 production continued from start of production in December 2016. The cycle 5 production strategy remained similar to previous cycles. HW3 is characterized by higher water production for the same operating pressures than the other wells and thus has operated at higher pressure over the late-stage production. A period of lower pressure operation was tested from October through November. Higher water-cuts and strong pressure support were observed, again indicating the different production characteristics of HW3 relative to the other wells.

2018

HW1 cycle 5 production was restarted in January after the pipeline plugging event of December 2017 was resolved. Normal operating strategy continued for this well. Production continued until late March after which pipeline plugging event led to a shut-in of the facility. Details of the pipeline plugging and well operation for the remainder of 2018 are given in Section 4.1.1.

HW2 cycle 4 was completed in March 2018. Cycle 5 injection was started in early March and production started in late March. Details of the April pipeline plugging event and well operation for the remainder of 2018 are given in Section 4.1.2

HW3 cycle 5 production was completed in March 2018 and cycle 6 injection was started thereafter. Details of the April pipeline plugging event and well operation for the remainder of 2018 are given in Section 4.1.3.

4 Production Performance

4.1 Injection and Production History

Total monthly injection volumes and per well volumes are shown in Tables 1 through 5. Total monthly production volumes are shown in Tables 7 through 11 with per well volumes given in Tables 13 through 25. A summary of annual injection and production volumes are shown in Table 6 and 12, respectively.

For each well and cycle, the narrative of injection and production events is described in the following sub-sections.

4.1.1 HW1 (Cycle 1 to 5)

The injection and production narrative for HW1 is described below:

HW1 Cycle 1 Injection

Injection started on February 5, 2016 with a target injection volume of 502 [m³] containing 12.5% (by volume) flow assurance solvent. The maximum injection rate of 125 [m³/D] was achieved early in the injection cycle and sustained through the completion of injection on February 9, 2016. The maximum sustained bottom-hole pressure was 10.8 [MPa] and the corresponding bottom-hole pressure of the nearest observation well (OB1, ~18 m lateral distance from HW1) was 10.1 [MPa].

HW1 Cycle 1 Production

Production began with flowback on February 12, 2016 with rates as high as 25 [m³/D] during the early stage of the production. The bottom-hole pressure of HW1 and OB1 were 6.6 and 7.0 [MPa], respectively. The rate gradually decreased with the natural decline of the bottom-hole pressure, as expected for a typical CSP production cycle. To improve production rates at lower downhole pressures, venting through the gas compressor was started on February 27, 2016. The late-stage bottom-hole pressures of HW1 and OB1 were 375 [kPa] and 2.1 [Mpa], respectively. Cycle 1 was completed on March 31, 2016 with minimal downtime.

HW1 Cycle 2 Injection

Solvent injection started on April 10, 2016 and finished April 15, 2016 with a total solvent volume of 678 [m³] with 11.5% (by volume) flow assurance solvent. The target rate of 150 [m³/D] was achieved during a ramp-up period and sustained for the duration of the injection cycle. The maximum sustained bottom-hole pressure was 9.2 [MPa] and the corresponding bottom-hole pressure of OB1 was 8.7 [MPa].

HW1 Cycle 2 Production

Production started on April 17, 2016 and a peak production rate of 35 [m^3/D] was achieved shortly thereafter. The bottom-hole pressures of HW1 and OB1 were initially 6.0 and 7.1 [MPa], respectively, and then declined naturally as the cycle progressed. Similar to the strategy used for HW1 Cycle 1 production, venting was used to improve production rates at lower downhole pressures during the late stage of the production cycle. An intermittent venting strategy, where HW1 and HW2 would alternate venting on a daily basis, was applied during the late-stage production due to the short-coming of the common vent-gas manifold, as described in Section 7.3. The late-stage bottom-hole pressures of HW1 and OB1 were 350 [kPa] and 2.0 [MPa], respectively. Production was completed on July 6, 2016.

HW1 Cycle 3 Injection

Injection started on July 12, 2016 with a target injection rate of 150 [m^3/D] achieved on the first day of injection and sustained throughout the injection cycle. A total of 1260 [m^3] of solvent with 12% (by volume) flow assurance solvent was injected with minimal downtime. HW1 Cycle 3 injection was completed on July 21, 2016. The maximum sustained bottom-hole pressure was 8.7 [MPa] and the corresponding bottom-hole pressure of OB1 was 8.4 [MPa].

HW1 Cycle 3 Production

Production started on July 22, 2016 and the production rate peaked at 38 [m^3/D] during the early stage of production. The bottom-hole pressures of HW1 and OB1 were initially about 6.7 and 8.0 [MPa], respectively. As expected, the rate then decreased along with the natural decline of the bottom-hole pressure. Intermittent venting was applied during the mid-stage production to increase the pump fillage and improve the production rates. The venting system was later improved with the installation of individual casing pressure control valves. For HW1, the installation was completed between October 5 and 13, 2016. Thereafter, production continued with continuous venting. On November 29, 2016 HW1 experienced a pump failure which was characterized by a loss of tubing pressure and no liquid production to the wellhead. The pump replacement began on December 1, 2016 and production was restarted successfully on December 5, 2016.

A previously scheduled mini-blowdown was then accelerated through December 2016. Aggressive venting was applied to bring the bottom-hole pressure from approximately 1000 [kPa] to less than 300 [kPa]. Higher than normal gas rates were achieved during this period and production continued through the year-end 2016. Production of late-stage cycle 3 continued into January 2017. A low pressure mini-blow down test continued with bottom-hole pressures lowered to approximately 250kPa. Higher than normal gas rates were achieved during this period. Cycle 3 production was completed on January 16, 2017.

HW1 Cycle 4 Injection

A pre-injection wellbore treatment was completed using 25.7 [m^3] of flow assurance solvent. Injection started on January 24, 2017 with a target injection rate of 150 [m^3/D] achieved on the first day of injection. The pressure response was gradual and as a result a higher injection rate of 165 [m^3/D] was sustained throughout remainder of the injection cycle. A total of 2174 [m^3] of propane solvent was injected for the cycle. HW1 Cycle 4 injection was completed on February 7, 2017. The maximum sustained bottom-hole pressure was 8.3 [MPa] and the corresponding bottom-hole pressure of OB1 was 7.9 [MPa].

HW1 Cycle 4 Production

Production began on February 10, 2017 with peak rates of about 35 [m^3/D]. The initial bottom-hole pressures of HW1 and OB1 were nearly equal at about 6.0 [MPa]. The BHP declined more quickly than previous cycles and lower corresponding production rates were observed. Continuous venting began on March 10, 2017 to improve the pump fillage during the mid-stage production thereby improving the liquid rates during low-pressure operation. The cycle completed on November 20, 2017. Bottom-hole pressures less than 500 [kPa] where achieved with a corresponding OB1 pressure of about 1.3 [MPa].

HW1 Cycle 5 Injection

A pre-injection wellbore treatment was completed using 27.1 [m^3] of flow assurance solvent. Injection started on November 21, 2017 with a target injection rate of 175 [m^3/D] achieved on the first day of injection. The pressure response was smooth and gradual and the target rate was maintained until mid-way through the cycle. Thereafter a lower injection rate of 165 [m^3/D] was sustained throughout the remainder of the injection cycle to align the end of injection with the M3 seismic shoot. A total of 3178 [m^3] of propane solvent was injected for the cycle. HW1 Cycle 5 injection was completed on completed on December 10, 2017. The maximum sustained bottom-hole pressure was 7.7 [MPa] and the corresponding bottom-hole pressure of OB1 was 7.4 [MPa].

HW1 Cycle 5 Production

Cycle 5 production began on December 11, 2017 with peak rates of about 32 [m^3/D]. The initial bottom-hole pressures of HW1 and OB1 were nearly equal at about 6.3 [MPa]. The pressure declined more slowly than cycle 4, but more rapidly than previous cycle. Smooth production continued until December 24, 2017, when production was shut-in due the production pipeline plugging with heavy liquid build-up.

It was expected that multi-well operation during this period would be challenging due to the phase behavior of the co-mingled flow from the three wells. HW1 production at this time was solvent rich, while HW2 and HW3 were late-stage production with higher bitumen cuts. The combination of the early production of HW1 with late stage production of HW2 and HW3 leads to unfavorable phase behavior that must be treated with flow-assurance solvent. Operational interruptions led to periods of low-treatment levels, which consequently deposited heavy liquid within the pipeline and then led to the eventual plugging. The pipeline was cleaned and production resumed on January 9, 2018.

Production continued until a planned pressure build-up from March 21, 2018 to April 4, 2018, which coincides with the early production period of HW2 cycle 5. The shut-in was longer than typical to mitigate the unfavorable co-mingled phase behavior with HW2 early production. Efforts were made at the time to reduce consumption of the flow assurance solvent due to an interruption in shipments of the solvent to site. By shutting in HW1, HW2 was the only well producing at the time, thereby reducing the flow assurance solvent requirements. Production resumed on April 4, 2018; however, operational malfunctions led to untreated co-mingled flow within the pipeline. The pipeline was plugged on April 13, 2018. In this instance a more significant work-over was required and pilot operation did not restart until June 13, 2018. HW1 remained shut-in to allow HW3 to produce the high solvent concentration fluid without co-mingling with the other wells.

The pad was shut-in on July 17, 2018 due to planned pipeline cleaning and integrity work, which was unrelated to the previous plugging events of 2018. Complications with pigging program extended the shut-in of pad to late September. The wells were started back online in a sequential manner with HW1 producing again on October 22. HW1 continued production through the end of 2018 with the cycle expected to end in mid-2019.

There was approximately 200 days of shut-in time in 2018 for HW1, with root causes related to malfunctions of the flow-assurance solvent system as well as complications during the pipeline integrity program. The downtime has led to lower cycle performance relative to previous cycles, but the differences are relatively small considering the length of downtime. Higher initial water-cuts with lower bitumen and solvent rates were observed.

4.1.2 HW2 (Cycle 1 to 5)

The injection and production narrative for HW2 is described below:

HW2 Cycle 1 Injection

Injection started on May 5, 2016 and after going through the initial ramp-up period, the target injection rate of 150 [m^3/D] was achieved and sustained until the end of the cycle on May 9, 2016. A total of 507 [m^3] of 100% propane was injected. The maximum sustained bottom-hole pressure was 10.6 [MPa] and the corresponding bottom-hole pressure of the nearest observation well (OB3, ~13m lateral distance from HW2) was 9.2 [MPa].

HW2 Cycle 1 Production

Production started on May 11, 2016 with early production rates were as high as 35 [m³/D] during the flow back period. The bottom-hole pressures of HW2 and OB3 were about 5.2 and 6.3 [MPa], respectively. The expected decline of the downhole pressure during the early stage of production resulted in a gradual drop in production rates. Venting was utilized to increase the pump fillage at lower downhole pressures and consequently to improve production rates at the late stage of the production cycle. The bottom-hole pressure was maintained at about 400 [kPa] during this period and the OB3 pressure was about 2.1 [MPa]. HW2 Cycle 1 was completed on June 30, 2016.

HW2 Cycle 2 Injection

Injection began on July 6, 2016 with a target injection rate of 150 [m³/D] achieved after an initial ramp-up period and was sustained throughout the injection cycle. A total of 599 [m³] of 100% propane was injected with minimal downtime. The bottom-hole pressure stabilized at 8.2 [MPa] and the corresponding OB3 pressure was about 7.6 [MPa]. HW2 Cycle 2 injection was completed on July 10, 2016.

HW2 Cycle 2 Production

Production started on July 13, 2016 with early stage rates that peaked at about 30 [m³/D]. The bottom-hole pressures of HW2 and OB3 were about 4.3 and 4.8 [MPa], respectively. The rate naturally declined along with the bottom-hole pressure until continuous venting began on July 25, 2016. Venting continued to the end of the production cycle to enhance the production rates at lower downhole pressures. The venting was intermittently shut-in to accommodate the required venting of the other wells. Late stage bottom-hole pressures were as low as 550 [kPa] with corresponding OB3 pressures as low as 2.0 [MPa]. HW2 Cycle 2 was completed on September 18, 2016.

HW2 Cycle 3 Injection

The venting system of HW2 was upgraded with a casing pressure control valve installation following the completion of Cycle 2. Injection then started on September 25, 2016 with a target injection rate of 150 [m³/D] achieved during the first day of injection and sustained through the injection period. A total of 1100 [m³] of 100% propane was injected with minimal down time. The bottom-hole pressure stabilized at 7.8 [MPa] and the corresponding OB3 pressure was about 7.4 [MPa]. HW2 Cycle 3 injection was completed on October 2, 2016.

HW2 Cycle 3 Production

Production started on October 4, 2016 with peak rates of about 35 [m³/D] during the early production period. The initial bottom-hole pressures of HW2 and OB3 were about 5.1 and

5.2 [MPa], respectively. Natural decline continued and the rates followed as expected. Continuous venting began on October 19, 2016 to improve the pump fillage during the mid-stage production thereby improving the liquid rates during low-pressure operation. By year-end the bottom-hole pressure was about 900 [kPa] with a corresponding OB3 pressure of about 1.8 [MPa]. Cycle 3 continued through the year-end 2016.

Production of late-stage cycle 3 continued into March 2017. Leading up to the M2 seismic shoot on February 8, 2017 the bottom-hole pressure was held constant at about 600 [kPa]. Thereafter, the BHP was progressively lowered by adjusting the venting pressure control. Cycle 3 production was completed on March 17, 2017.

HW2 Cycle 4 Injection

A pre-injection wellbore treatment was completed using 42.7 [m³] of flow assurance solvent. Injection started on March 21, 2017 with a target injection rate of 150 [m³/D] achieved on the first day of injection. The pressure response was smooth and gradual and the target rate was sustained throughout remainder of the injection cycle. A total of 1963 [m³] of propane solvent was injected for the cycle. HW2 Cycle 4 injection was completed on completed on April 3, 2017. The maximum sustained bottom-hole pressure was 7.4 [MPa] and the corresponding bottom-hole pressure of OB3 was 7.0 [MPa].

HW2 Cycle 4 Production

Production began on April 5, 2017 with below normal rates of about 15 [m³/D]. The bottom-hole pressures of HW2 and OB3 were nearly equal at about 5.2 [MPa]. The well was shut-in after 5 days of production and the pump was replaced on April 19, 2017. Thereafter, peak rates production were achieved at about 38 [m³/D]. The BHP declined naturally and the flowrate followed as expected. Continuous venting began on May 8, 2017 and typical mid-stage production was achieved. A low-pressure mini-blow down test was initiated in October and carried through until December 24, 2017. During this period relatively higher venting rates were observed and bottom-hole pressures less than 500 [kPa] where achieved with a corresponding OB3 pressure of about 1.4 [MPa]. Production was shut-in on December 24, 2017 due to the heavy liquid build-up in the pipeline. The mini-blow down test was effectively terminated due to the shut-in. Cycle 4 production was resumed after the pipeline workover was completed in January of 2018. Production of late-stage cycle 4 continued into 2018 with cycle production completed on March 2, 2018.

HW2 Cycle 5 Injection

A pre-injection wellbore treatment was completed using 30.9 [m³] of flow assurance solvent. Injection started on March 4, 2018 with a target injection rate of 170 [m³/D] achieved on the first day of injection. The pressure response was smooth and gradual and the target rate was sustained throughout remainder of the injection cycle. A total of 3188 [m³] of propane solvent was injected for the cycle. HW2 Cycle 5 injection was completed on completed on March 23, 2018. The maximum sustained bottom-hole pressure was 7.4 [MPa] and the corresponding bottom-hole pressure of OB3 was 6.9 [MPa].

HW2 Cycle 5 Production

Production began on March 25, 2018 with an average rate of about 34 [m³/D]. The bottom-hole pressures of HW2 and OB3 were nearly equal at about 5.0 [MPa]. Thereafter, peak rates were maintained between 45 and 50 [m³/D]. During this period HW2 was the only well producing while HW1 was shut-in for a pressure build-up (as described above) and HW3 was on injection. Higher than normal rates were sustained to produce the early production fluid more rapidly. Such rates would not be possible if HW2 were co-mingled with HW1 because of the volume of flow assurance solvent required to mitigate heavy liquid plugging. On April 4, 2018 production of HW1 resumed. As described with regards to HW1 Cycle 5 production, operational malfunctions led to untreated co-mingled flow within the pipeline. The pipeline was plugged on April 13, 2018. The plug was removed on June 13, 2018 but HW2 was kept shut-in to allow HW3 to produce.

The pad was shut-in on July 17, 2018 due to planned pipeline cleaning and integrity work. Complications with pigging program extended the shut-in of pad to late September. The wells were started back online in a sequential manner with HW2 producing again on September 27. HW2 continued production through the end of 2018 with the cycle expected to end in late 2019.

There was approximately 170 days of shut-in time in 2018 for HW2. There have been minor effects on production metrics for the current cycle. The water cut was higher after shut-in, but has returned to prior cycle tends at the end of 2018.

4.1.3 HW3 (Cycle 1 to 6)

The injection and production narrative for HW3 is described below:

HW3 Cycle 1 Injection

HW3 was the first well come online and there was significant operational learnings from this first cycle. Solvent injection occurred from May 29, 2014 to June 8, 2014. There was intermittent injection at times reaching 150 [m³/day] from May 29, 2014 to June 2, 2014. Interruptions were related to the tuning of the injection control system and the fouling of the solvent filters. Injection was halted from June 3, 2014 to June 6, 2014 while off-spec diluent removed from CSP tanks and replaced with new product. Steady injection began again on June 7, 2014 and continued through June 9, 2014 with rates at 150 [m³/day] for nearly 60 [hrs] until first injection volume target reached. The bottom-hole pressure peaked at 9.7 [MPa] and the corresponding OB3 pressure was about 6.9 [MPa]. HW3 cycle 1 injection was completed on June 8, 2014 with a total of 522 m^3 of solvent injected.

HW3 Cycle 1 Production

Production from HW3 occurred from June 10, 2014 to June 12, 2014. The pad was shut-in from June 13, 2014 to August 11, 2014 due to due to hydrate and heavy hydrocarbon liquid phase formation issues in the surface facilities.

There was intermittent production from August 11, 2014 to August 14, 2014 and August 22, 2014 to August 27, 2104, but limited production due to surface facility issues. To stimulate the well, a mini-injection of 64.9 [m^3] of solvent was completed between September 3, 2014 and September 4, 2014. Production continued intermittently from September 4, 2014 to September 11, 2014, but was hampered by surface facility plugging with heavy liquid. The pilot was subsequently shut-in from September 2014 until April 2015 in order to evaluate challenges related to the facility. During the shut-in period facility improvements were planned and a new flow assurance solvent was sourced to mitigate the surface facility plugging.

HW3 cycle 1 production was restarted on April 8, 2015 following a wellbore treatment with a new flow assurance solvent. Production continued until June 8, 2015. The introduction of the flow assurance solvent resulted in a step change in facility performance. However, the pipeline differential was still a significant bottleneck for future operations. Gas production through the pipeline was limited to impractically low flow rates and future multi-well operation would not be possible. The pipeline was re-rated from an MOP of 1850 to 3675 [kPa] and was successfully hydro-tested prior to cycle 2 injection on June 18, 2015.

HW3 Cycle 2 Injection

Cycle 2 injection then started on June 18, 2015 and continued to June 24, 2015. The initial injection rate was throttled below the 150 [m^3/D] target rate to maintain bottom-hole pressures less than 12 [MPa]. The maximum reservoir pressure observed in the nearest observation well (OB5) was less than 8 [MPa], suggesting the higher than normal bottom-hole pressures were caused by plugging of the ICDs. Pauses during injection indicated near-well pressure drop of about 3 [MPa], much higher than the anticipated pressure drop of 0.5 to 1 [MPa].

The wellbore was not treated prior to the cycle 2 injection and the formation of heavy phase within the wellbore during injection was the suspected cause of the plugging and corresponding elevated bottom-hole pressures. Subsequent injections, performed after a wellbore treatment, were not restricted by the bottom-hole pressure thereby confirming the suspected cause of the plugging for cycle 2.

Injection finished on June 24, 2015 with a total of 601.9 [m^3] of solvent injected.

HW3 Cycle 2 Production

Production began on July 1, 2015 after a pressure-fall period. Production was smooth and continued to September 4, 2015 with no periods of downtime in excess of 8hrs. The total production rates exceeded 30 [m^3/D] and declined with the reservoir pressure over the course of the cycle. The instantaneous water-cut exceeded 50% at times during this cycle. Flow assurance solvent was used at the surface and within the wellbore. Compared to cycle 1 the total flow assurance solvent used was significantly reduced. With the higher trunkline MOP the production was not limited by the pipeline pressure differential, as is was in cycle 1.

HW3 Cycle 3 Injection

Prior to cycle 3 injection the wellbore was treated with flow assurance solvent. Cycle 3 injection began on September 15, 2015 and continued until September 23, 2015. After an initial ramp up period the target injection rate of 150 [m^3/D] was achieved. A planned mid-injection pressure fall-off test was conducted on September 19, 2015. The results showed a small pressure drop (<300 [kPa]) between the well-bore and reservoir, indicating no plugging and positive flow through all of the ICDs. The pre-cycle wellbore treatment was successful in mitigating the plugging issues experienced during the cycle 2 injection.

HW3 Cycle 3 Production

Production commenced on September 25, 2015 and continued uninterrupted until October 18, 2015 at which point production was shut-in for a two-day planned pressure build-up test. Thereafter, production continued until November 25, 2015. The pilot was shut-in to accommodate repairs to an access bridge. Wellhead heat-tracing was also installed during this shut-in. Production resumed on December 11, 2015 and continued until December 26, 2015. The pilot was shut-in at this point for the planned facility upgrades in January of 2016, which included the installation of a compressor skid.

Production was restarted on January 31 after facility modifications were completed during a planned pad shut-in beginning on December 27, 2015. Cycle 3 resumed during the late-stage production with initial rates as high as 14 [m^3/D]. Lower pressure operation was attempted by venting the casing gas through the newly installed compressor package. The gradual reduction of BHP led to a significant increase in the water production, with limited benefit to the hydrocarbon production. In general, HW3 water production through cycles 1 and 2 was higher than the nominal pre-pilot expectations and therefore the observed increase in water production at lower pressures was anticipated. Consequently, the lower pressure operation for HW3 was generally avoided other than a planned test of sustained lower pressure during the late-stage of cycle 4. HW3 Cycle 3 production competed on March 20, 2016.

HW3 Cycle 4 Injection

Injection started on March 23, 2016. A total solvent volume of 1800 [m³] with 12% (by volume) of flow assurance solvent was injected with minimal stoppage. The injection rate ramped up smoothly to the target value of 150 [m³/D] and remained at this level until the end of injection on April 4, 2016. The bottom-hole pressure stabilized at 7.7 [MPa] and the corresponding pressure of the nearest observation well (OB5, ~16m lateral distance from HW3) was about 7.2 [MPa].

HW3 Cycle 4 Production

Production started on April 6, 2016 with early stage rates that peaked at about 37 [m³/D]. The bottom-hole pressures of HW3 and OB5 were both about 5.5 [MPa], respectively. An intermittent venting strategy was applied to the majority of the cycle to maintain the pump fillage as the bottom-hole pressure declined. Continuous venting was trialed starting on October 6, 2016 following the installation of the casing pressure control valve. The bottom-hole pressure was lowered from 2.0 [MPa] to 800 [kPa] by October 24, 2016 and then held constant for the duration of the cycle, which was competed on November 27, 2016. The corresponding late-stage OB5 pressure was 2.0 [MPa].

HW3 Cycle 5 Injection

Injection started on November 27, 2016. A total solvent volume of 2941 [m³] with 6% (by volume) of flow assurance solvent was injected. The injection rate ramped up smoothly to about 162 [m³/D]. Despite the brief shut-ins due to winter operational challenges, the cycle injection was ultimately completed on schedule by December 17, 2016 and the target volumes were achieved. The bottom-hole pressure stabilized at 7.0 [MPa] and the corresponding OB5 pressure was about 6.6 [MPa].

HW3 Cycle 5 Production

Production started on December 19, 2016 with early-stage rates that peaked at about 37 [m³/D]. The bottom-hole pressure of HW3 was initially about 5.5 [MPa]. The cycle 5 production strategy remained similar to previous cycles. HW3 is characterized by higher water production for the same operating pressures than the other wells and thus has operated at higher pressure over the late-stage production. A period of lower pressure operation was tested from October 2017 through November 2017. Higher water-cuts and strong pressure support were observed – again indicating the different production characteristics of HW3 relative to the other wells.

There was minor downtime in from December 25, 2017 to January 9, 2018 due to pipeline plugging. HW3 cycle 5 continued to produce into 2018 with cycle production completed on March 21, 2018.

HW3 Cycle 6 Injection

Injection started on March 23, 2018. A total solvent volume of 4824 [m^3] was injected with 6.9 [m^3] of flow assurance solvent used for wellbore cleaning. The injection rate was about 175 [m^3/D]. The cycle injection was completed on April 22, 2018. The bottom-hole pressure stabilized at 7.7 [MPa] and the corresponding OB5 pressure was about 7.2 [MPa].

HW3 Cycle 6 Production

Production was scheduled to begin after injection on April 25, 2018. However, due to the pipeline plugging issues described in the sub-sections above, HW3 cycle 6 production was delayed until the pipeline plugging was fully mitigated.

The pilot was re-started with HW3 coming online on June 13, 2018. Early production rates peaked at about 55 [m^3/D]. The bottom-hole pressures of HW3 and OB5 had naturally declined to 3.5 [MPa] prior to the restart. Again, high rates were sustained to produce the solvent rich fluid more rapidly and thereby reduce the volume of flow assurance required to mitigate heavy liquid plugging. The rate was lowered to 30 [m^3/D] by July 10, 2018 as the bitumen fraction of the produced stream increased.

Planned pipeline cleaning and integrity work began on July 17, 2018 with all three wells shut-in. Complications with pigging program extended the shut-in of pad until late September. The wells were restarted in a sequential manner with HW3 producing again on October 1, 2018. HW3 production continued through the end of 2018 with minimal downtime.

There was approximately 125 days of shut-in for HW3 cycle 5 in 2018. There has been some off trend behaviour with higher bitumen rates, lower solvent and increased water cuts relative to previous cycles.

HW3 cycle 6 is expected to continue to produce into 2020.

4.2 Composition of Injected and Produced Fluids

By the end of 2018 a total of 13 production cycles had been completed since pilot start up. There are three cycles ongoing into 2019 (HW1 cycle 5, HW2 cycle 5, and HW3 cycle 6). The production characteristics of each well were similar in terms of key performance metrics, such as the total hydrocarbon recovered and the solvent recovery. The water production of the three HWs remains different, as was noted in the past IETP reports. Although the cycles of each well are not synchronized in time, HW3 is an outlier in terms of water production considering that the well has generally operated at higher pressures over late-stage production. The difference in water production is attributed to differences in the local water mobility and strong pressure support.

The injected fluids since start-up have been propane, diluent, and flow assurance solvent. The propane is industrial grade propane with an average of 98 mass% of C3. The diluent composition can vary depending on the source plant however for this pilot the diluent selected is primarily C5 with only a small fraction being above C8. Diluent density is in the range of 650 to 690 [kg/m^3]. The composition of the flow assurance solvent is the subject of patent CA2900178.

Produced fluids can be comprised of methane, propane, diluent, flow assurance solvent, bitumen, and water. Over the course of the production cycle the composition of the produced fluid changes. The determination of composition happens in two parts. The first part is an initial estimate derived from pad measurements of masses, densities, and water-cuts. The estimate requires several assumptions to make a density-based split of propane, diluent, flow assurance solvent and bitumen. The second step happens afterwards once the compositional analysis of physical samples is completed and results are incorporated into the overall analysis. The compositional analysis itself includes gas chromatographs (GC) up to C6 for the volatile gas portion and up to C30+ for the remainder. Individual substances can then be identified from the mixture by their characteristic shapes on the GC outputs. Figure 8 shows examples of the characteristic shapes for each liquid phase substance.

The injection composition was not held constant through the pilot life. Below is a summary of the injection composition per well and cycle:

HW1 Cycle 1 through 3

- The injected solvent was approximately 88 vol% propane and 12 vol% flow assurance solvent

HW1 Cycle 4 Injection

- Nearly 100 vol% propane, with flow assurance used only for pre-injection wellbore treatments

HW1 Cycle 5 Injection

- Nearly 100 vol% propane, with flow assurance used only for pre-injection wellbore treatments

HW2 Cycle 1 through 5 Injection

- Nearly 100 vol% propane, with flow assurance used only for pre-injection wellbore treatments

HW3 Cycle 1 Injection

- The solvent injected was 88 vol% propane and 12 vol% diluent
- During production in September 2014, a mini-injection with 86 vol% diluent and 14 vol% propane was used to stimulate production and alleviate heavy liquid phase issues

HW3 Cycle 2 through 4 Injection

- The injected solvent was approximately 88 vol% propane and 12 vol% flow assurance solvent

HW3 Cycle 5 Injection

- The injected solvent was approximately 94 vol% propane and 6 vol% flow assuranc

HW3 Cycle 6 Injection

- Nearly 100 vol% propane, with flow assurance used only for pre-injection wellbore treatments

4.3 Simulation and Prediction of the Pilot Performance

The CSP simulation capabilities were developed over the course of the pilot program with the pilot data, including the sample analysis program, providing the basis for history matching. The CSP simulation development followed a structure program involving the implementation of key features into the in-house simulation code that aim to represent the physics of the CSP processes followed by the tuning of key parameters to the pilot data. The tuning parameters were consistent across all wells and all cycles in an effort to ensure the model is robust and is also predictive.

The simulation results are compared to the pilot data in terms of key performance indicators, such as the total hydrocarbon recovery, solvent recovery, oil-to-injected solvent ratio and cumulative water-cut. Table 32 shows the percent error of the simulation cumulative bitumen, solvent and water production relative to the pilot. As shown, for each well a suitable match of the key metrics has been achieved. HW1 shows the largest cumulative differences relative to the pilot results. The difference are attributed to a distinct change in the reservoir solvent conformance that occurred in HW1 between cycles 3 an cycle 4. The details of the conformance changes are described in Section 5.4.7, with reference to the 4D seismic results. For brevity here, a new solvent lobe was observed in the 4D seismic results after cycle 4 injection. The new lobe is observed in a previously uncontacted region of the reservoir towards the heel of the well. The uncontacted region would then have production characteristics similar to CSP cycle 1, thereby lowering the overall bitumen and solvent production of the cycle 4. Since the simulation model did not explicitly model a pathway to this uncontacted region, it was not able to predict the performance impact of the newly formed lobe.

Figure 9 shows the monthly averaged pressure data for each horizontal well. The pressures from the history matched simulation model are overlaid for reference. In general, the history matched model is consistent with the pilot measurements, particularly during the production cycles, which is an indicator of that the reservoir solvent conformance and depletion has been adequately modelled. Figure 9 also shows a shortcoming in the model's ability to match the injection pressures. The HM pressure tends to overshoot the pilot measurements during the injection period. The difference in the pressures is thought to be related to the grid size used for the model which not refined enough to fully capture the intricate network of viscous fingers present in the pilot.

4.4 History of Pressure Measurements

Monthly average pressures for the HWs and the corresponding observations wells are shown in Tables 33 through 37. The horizontal well pressures are shown Figure 9 (as noted in Section 4.3).

5 Pilot Data

5.1 Introduction to the Additional Pilot Data

The additional pilot data and corresponding interpretation is discussed in the following sub-sections. The pilot geology is described in Section 5.2 which is followed by a discussion of the pre-start up cross-well borehole tomography. Section 5.4 describes the post-start up subsurface surveillance program. The objective of the post-start up subsurface measurements is to map the reservoir and wellbore solvent conformance.

5.2 Geology

The pilot is being conducted in the Clearwater formation. A cross-section of the reservoir, through the observation wells, is shown in Figure 10. The reservoir consists of two sequences: the lower sequence, between the lower sequence boundary (bright green line in three wells in Figure 10) and the upper sequence boundary (purple line in Figure 10); and, the upper sequence between the upper sequence boundary and the top of the Clearwater formation (red line in Figure 10). The primary target is the lower sequence, with an average thickness of 21 m. The depth of the horizontal wells is shown approximately by the dashed dark green line in Figure 10.

The sands are generally clean, although one noticeable feature on the logs is the calcite cemented zones (colored blue in Figure 10). From core, we believe these features to be limited in areal extent. Observation of similar features elsewhere in the development would suggest their impact on conformance should be limited. Should the calcite zones be more extensive and have zero permeability, they may change the conformance of the solvent-invaded zone, but should not impact our ability to interpret the pilot results. Heterogeneity is higher in OB1 through OB5 than in the first well 14-18, upon which the site was picked. Again, this increase in heterogeneity is not expected to adversely impact the pilot results.

Also noticeable from Figure 10 is that three of the OB wells were drilled shallower than the other three. This was to avoid a higher water saturation zone below the Clearwater formation. Although the wells are cemented, it was decided not to penetrate that sand in the last three wells.

5.3 Cross-Well Borehole Tomography

Pilot surveillance plans include shooting cross-well borehole tomography between the wells in an effort to better identify and quantify the conformance of the solvent injection. An initial base survey has been completed, with two repeat surveys, for solvent mapping, in the plan.

The base survey was completed in April 2012, with processing and interpretation taking place over the rest of the year. Nine lines were shot, as shown in Figure 11. The longer lines used ZTrac sources, the shorter lines used piezo-electric sources. The results of all nine lines are shown in Figure 12. For better illustration of the results, a representative ZTrac line, OB-1 to 14-18, is shown in Figures 13 and 14. A representative piezo-electric line, OB-2 to OB-3 is shown in Figures 15 and 16.

Results of the base cross-well borehole tomography are as follows:

- The surveys were very useful in defining the structure of the Clearwater Formation for use in the geological model. The base 3D seismic survey and the base cross-well borehole tomography survey were complementary.
- The surveys assisted in identifying areas of carbonate concretion deposition. The surveys confirmed initial modeling that the carbonate concretion deposition is not a continuous bed.
- A significant amount of noise was realized in the piezo-electric lines, due primarily to the proximity of the wells, some less than 50 m apart. Initial processing was successful at removing a large amount of the noise, but at the cost of some of the frequency.

The baseline results provide little uplift over 3D surface seismic imaging and therefore improvement methods were evaluated in the subsequent reporting period.

In 2013, methods of improving the cross-well seismic data were evaluated. After additional reviews of the data, it was determined that the value of repeat cross-well surveys was limited and thus was dropped from the surveillance program. Repeat 3D seismic surveys and passive seismic monitoring (in three of six the observation wells) would remain as part of the sub-surface conformance surveillance plan.

5.4 Post-start up Subsurface Surveillance

5.4.1 Introduction to Sub-Surface Surveillance Measurements

The subsurface instrumentation is used to infer the solvent conformance within the reservoir as well as the distribution along the wellbore. The objective of the OB program at the CSP pilot is to monitor and interpret the solvent conformance within the reservoir. A secondary objective was to test the functionality of the different measurement systems as they apply to the CSP process. The solvent distribution along the wellbore during injection, the wellbore conformance, is inferred using the measured temperature distribution.

The following sub-sections include the results and interpretation of solvent conformance. Physical explanations are detailed throughout.

5.4.2 Summary of the OB Well Solvent Detection

The current section summarizes the findings regarding solvent arrival at the OB wells. Sections 5.4.3 and 5.4.5 provide detailed analysis and interpretation that led to the findings below.

Table 38 gives an overall summary of solvent arrival detection for all of the OB wells. As shown, OB2 does not detect solvent arrival. It is not perforated and only has passive seismic instrumentation. The passive seismic instrumentation has not been successful in locating reservoir events associated with fluid movement. Similarly, wells with heated DTS but no perforations, such as OB4 and OB6, do not detect solvent arrival. It is likely that solvent has not reached OB6 as it is located 36 [m] laterally from the HW2. However, OB4 is 20 [m] from HW3 and is within the reach of the solvent during Cycles 4 or 5. A response has not been measured on OB4 during injection.

OB3 is the only well that is both perforated and instrumented with a heated DTS system. Since the ERD and DTS systems measure a response on OB3 it provides the most information for interpretation. Section 5.4.3 and 5.4.5 utilize the OB3 measurements to interpret the solvent arrival in general. The learnings are applied to the other wells were applicable. For instance, OB1 and OB5 are perforated and have passive seismic geophones. Solvent arrival is inferred from the BHP response and not the passive seismic system.

5.4.3 Design Intent of OB Well Instrumentation

The OB well instrumentation was designed to map or at least provide insights into the reservoir solvent conformance – a key technical objective of the pilot. Prior to pilot start-up the chance of success of the different OB instrumentation was largely unknown. The OB instrumentation was informally considered an instrumentation pilot within the overall CSP pilot. The learnings of the OB program are important for the instrumentation selection for the OB wells in a commercial program. In the present section, the design objectives for each type of instrumentation are detailed. The subsequent sections then describe the measurement interpretation and the relation to the original design intent.

ERD (Electrical Resonating Diaphragm) sensor: The objective is to measure the pressure and temperature of a perforated OB well. The perforations allow communication with the reservoir and therefore the ERD sensor is a point measurement of the reservoir temperature and pressure – assuming the pressure drop through the perforations is small. By design a BHP response of the OB well during injection is interpreted as the arrival of the advancing solvent front. The BHP then provides the minimum lateral extent of the solvent chamber.

DTS thermal fiber is a distributed fiber optic string that measures temperature along the vertical direction of the OB well at 1m increments. The fiber is affixed to the tubing and the casing annulus is water filled or cemented. A distributed heater is also affixed to the tubing on OB3, OB4 and OB6 which increases the nominal temperature of the fiber relative to the surround reservoir, thereby increasing the sensitivity of the sensor to small temperature changes.

By design the DTS fiber was intended to map the vertical distribution of the solvent chamber. An illustration is shown in Figure 17 and depicts two scenarios in which a perforated OB well may respond. In scenario (1) the solvent fingers contact the outer casing causing a cooling effect that is measured by the DTS string along the tubing, thereby yielding a 2D interpretation of the solvent conformance in the reservoir. In scenario (2) the solvent finger moves into the tubing through the perforations and the fluid movement within the tubing causes a temperature response. In scenario (2) only fluid arrival is measured. Scenario (1) represents the design intent of the DTS system while the following sub-sections will show scenario (2) is what actually occurs at the CSP pilot.

Passive seismic geophones are distributed in the vertical direction within the tubing of the OB well. Passive seismic systems have commercial uses in Cold Lake for monitoring casing integrity and fluid excursion events. The technology was adopted to the CSP OB program to monitor events occurring within the reservoir during injection. Events that generate a distinct P and S wave are locatable in three-dimensional space. The design intent of the passive seismic system was to generate a 3D map of events created during the injection period, whereby the map is representative of the solvent fingering through the native pore space. In general, the CSP process occurs at relatively low pressures (compared to CSS) and the recorded events of the PS systems have not been distinguishable from the background noise.

5.4.4 Passive Seismic Subsurface Solvent Conformance

The follow sub-section describes the observations collected with CSP passive seismic (PS) system. The CSP pilot has three passive seismic (PS) OB wells (one located close to each horizontal well) with geophones in the Clearwater to detect the small micro-seismic event cause by solvent movement and gain a quantitative understanding of solvent conformance. This is a novel application of PS geophone typically employed to detect events of much larger magnitude such as casing failures. Two factors that make the CSP micro-seismic events particularly difficult to detect are their extremely low energy level and the tendency of the Clearwater formation to dampen the signal. Figure 18 shows two views of the detected events plotted in three dimensions relative to HW3, OB4, and OB5. The majority of the detected events are clustered around the toe of HW3 and reach towards OB5.

The combined pressure, temperature, and passive seismic data from HW3 and OB5 (approximately 16 [m] from HW3) present strong evidence a solvent finger passed by OB5. Near the end of HW3 injection, there was a step change in the previously slow pressure response at OB5. Several hours later, the PS events detected by OB5 transitioned from primarily reservoir type events to Stoneley wave type evens (vibrations along the wellbore) indicating fluid reaching the well. Finally, there was also a small but notable change in the OB5 bottom-hole temperature. The corroboration between these three observations helps to both establish solvent conformance as well as successfully demonstrate the use of PS to detect CSP fluid movement.

During Q4 of 2014, there was a significant effort to better understand, quantify, and ultimately resolve the heavy liquid phase facility plugging issues. Several solvents were assessed through bench tests, EOS modeling, and PVT experiments. Based on effectiveness, availability, and cost, a catalytic distillate with high aromatics content was selected as the best solvent for CSP facility flow assurance.

In 2015, after the pilot restart, the PS of next injection cycles did not lead to effective mapping of the solvent chamber. HW3 cycle 2 injection did not yield locatable events as observed during cycle 1 injection. In fact, only lower energy events were observed within the vicinity of OB5. The low energy events are similar in magnitude to the background noise and are not locatable. Thus, for the purpose of determining the solvent conformance the observed events were not useful. Comparing to cycle 1, the lower energy level and number of reservoir events is attributed to the lower reservoir pressures achieved during injection. Also, the solvent would likely travel through channels created during cycle 1, thereby leading to a lower number of detectable events.

Secondary events, termed Stoneley waves, are formed when a wave generated from a reservoir event hits the perforations of OB5. The Stoneley waves then “ring” (travel) up the tubing and casing. Stoneley waves and the corresponding reservoir events were observed near the end of the injection cycle and for two days after. A few of these reservoir events were locatable to OB5 at 460mTVD, suggesting the solvent had reached OB5 and was continuing to move within the reservoir after the injection had stopped.

The PS results for cycle 3 injection are similar to those of cycle 2. Moderate energy locatable events were not detected. Again, similar to cycle 1, the lower reservoir pressures led to lower energy events which were masked by the background noise. Stoneley waves were also observed and are again evidence of the solvent finger reaching OB5.

5.4.5 OB Fluid Arrival Interpretation using OB temperature and Pressure Measurements

The present section documents the typical response of a perforated OB well during an injection cycle. Measurements from OB3 and HW2 Cycle 3 are used as an example to aid the general interpretation.

A summary of HW2 Cycle 3 injection is shown in Figure 19. The injection rate, HW BHP and the OB3 BHP is shown in sub-figure (a) while the thermal response of the DTS system is shown in sub-figure (b). As shown, the heater was activated on Sept. 16, 2016 prior to the start of cycle 3 injection. Sufficient time is required to allow the OB well to reach a pseudo-steady temperature. Primary solvent injection began on Sept. 25, 2016, thereafter a steady increase in the HW BHP is observed. As shown, the bottom-hole pressure of OB3 follows the HW BHP, and lags slightly as expected. A distinct cooling response is observed on Sept. 27, 2016. The cooling is coincident with the rise in the OB BHP, suggesting that injectant has arrived at the OB well.

Figure 20 (a) shows a color flood of the temperature measured from the DTS fiber as function of the depth and relative time, where the time zero is set just before the cooling response. The corresponding OB pressure response is also plotted below the color flood for reference. Important depths such as the HW, OB perforations and the heater top are indicated.

The color flood in Figure 20 (a) shows a lower temperature region near the perforations that is coincident with the OB BHP pressure rise. The cool region extends vertically away from the bottom of the DTS fiber up to about ~25m above the HW. Considering scenario 1 of the two possible sensing scenarios described in Section 5.4.3, it is unlikely that solvent would travel to this height within the reservoir at this stage of the CSP process. Scenario 2 may be more likely – that the solvent would move through the tubing causing cooling along the interior of the tubing.

To further investigate Scenario 2 consider Figure 20 (b). Here the color flood represents the temperature difference relative to the time zero temperature at each depth location. Two distinct regions are evident – one that is cooler than the initial condition and one that is warmer. As shown a cooling signal initially occurs at the bottom of the fiber, as labelled. Cooling in this region (near the perforations) is caused by inflow of colder solvent or a mixture of solvent bitumen and water. When fluid moves into the perforations and up the tubing the original fluid within the tubing is displaced vertically. The displaced fluid is warm due to the heating that occurs prior to inflow. As the warm tubing fluid moves above the heater top and into a cooler section of the tubing a heating signal is measured, as shown in Figure 20 (b). Heating is also observed slightly below the heater because the time-zero vertical temperature distribution is not uniform.

The OB BHP is also shown in Figure 20 (b). As the fluid moves into the tubing the pressure rises gradually at first. The headspace above the fluid is gradually compressed. Eventually the fluid level reaches the top of tubing causing the pressure to rise rapidly. The rapid pressure rise is coincident with both the peak cooling signal near the perforations and the peak heating signal near the heater top. Effectively, the tubing fluid stagnates and heat transfer reverses. The cooler fluid that had moved into perforations begins to heat up, as indicated. The warm fluid that was displaced above the heater top begins to cool down, as indicated. The rebound of the temperatures back to the pseudo-steady state is depicted clearly in Figure 19 (b).

For brevity only HW2 cycle 3 is shown here, but similar results were measured for the other cycles.

In summary, the DTS measurements of OB3 are consistent with Scenario 2. Fluid moves through the perforations and up the tubing causing a response of DTS system. The response is correlated in time with the pressure response. Therefore, the learnings from OB3 can be transferred to other perforated OB wells without a heated DTS system. A sharp pressure response that lags the HW BHP is indicative of fluid arrival at the OB well. Furthermore, OB wells without perforations have not shown a DTS response during injection (see Table 38), suggesting that a signal arriving at the casing through the reservoir is too subtle to detect through the annulus. Effectively, the water filled annulus insulates the sensor that is affixed to the tubing. The present design is more appropriate for thermal process with large temperature gradients. In a cold process like CSP, the design should consider the following:

- On perforated wells the fluid influx into the tubing dominates the DTS response if the fiber and heat are affixed to the tubing
- The pressure response is correlated with fluid arrival
- The water filled annulus insulates any response from reservoir and perhaps the heater and DTS should be affixed to the casing
- The noise level of the current heater and DTS is too high to detect subtle changes to the reservoir. Cementing the annulus may be an option for noise reduction.

Lastly, in the present interpretation the composition of the fluid inflow was not identified. The sensed change in temperature and pressure does not directly indicate the fluid composition, only that a fluid has arrived. Although it seems obvious the fluid is likely solvent, thereby allowing the extent of the solvent chamber to be inferred, another possibility exists. During injection it is possible the inflowing fluid is simply mobile water that is displaced to the OB well by the solvent front. In this situation the breadth of the water front is unknown, which adds to the uncertainty to the inferred extent of the solvent chamber. However, other measurements such as the 4D seismic have been useful in visualizing the solvent conformance, which was consistent with the lateral extents of the chamber inferred by the OB well measurements. The overall conclusion is that the OB wells show a rapid rise in pressure that characterizes the arrival of fluid at the OB well. The fluid composition is expected to a combination of solvent and reservoir fluids, and provides an indication of the lateral extent of the solvent chamber.

5.4.6 HW Wellbore Utilization

Wellbore conformance is also referred to as the wellbore utilization. It is a measure of the capability of a well to deliver solvent uniformly along its length during injection. The conformance can be interpreted from the HW temperature. As described previously, HW3 did not have a functional thermocouple string, so wellbore analysis herein only pertains to HW1 and HW2.

The mass distribution of the injection fluid along the wellbore can be inferred from the measured temperature distribution. An analytical convective heat transfer model is used to match the measured temperature along the wellbore for a specific mass flow distribution. The relative mass flow ratio of the injection fluid along the wellbore is tuned such that the predicted temperature profile matches the measured data. An example is shown in Figure 21. The horizontal axis is the position along the wellbore length (~100m) and the vertical axis represents the wellbore temperature. The symbols are the measured thermocouple data and the solid lines are the results of the analytical model. The blue line represents the hypothetical uniform conformance case, such that each of the five ICDs receives 20% of the injected mass flow. As shown, the predicted temperature of the uniform distribution is too high at the toe of the wellbore. The tuned case is also shown, as indicated. The mass flow is reduced at the toe ICD such that the measured temperature profile is matched. The implication is that during this particular cycle, less solvent was delivered to the toe of the well.

Similar examples were observed for the other cycles of both HW1 and HW2. A summary of the utilization results is given in Table 39 for all of the completed cycles. As shown, early cycles have non-uniform utilization, while later cycles become more uniform cycle over cycle. HW1 cycle 4 and 5 have unphysical temperature distributions which were likely caused by poor quality thermocouple measurements. The analysis results are therefore not included here. In summary, the pilot has demonstrated sufficient wellbore utilization that is aligned with the project goals and technical objectives. The information here is also important for the wellbore design of potential commercial project.

5.4.7 4D Seismic

As described in Section 2.2.5, three seismic shoots were completed to image the sub-surface solvent conformance. The timing of the shoots is given below and was selected to capture an array of operating conditions for each of the three wells.

- Monitor 1 (M1) shoot on December 18, 2016
- Monitor 2 (M2) shoot on February 8, 2017
- Monitor 3 (M3) shoot on December 10, 2017

The three shoots named above are complimentary to the baseline shoot preformed in 2010, prior to the pilot start-up. Difference maps in time show the distribution of solvent relative to the native reservoir. The ability to successfully visualize the solvent chamber at both high and low pressure operating conditions was uncertain prior to performing the shoots. Figure 22 shows the inferred solvent chamber boundary for the three shoots. As shown, HW3 has a solvent chamber that had spread farther away from the wellbore in the horizontal plane than the other two wells – a result that is consistent with the observed higher water-mobility. HW2 showed nearly uniform conformance from heel to toe, while HW1 showed a distinct change in conformance from cycle 3 to cycle 4. In cycle 3, the conformance was uniform and similar in magnitude to the HW2 chamber. In cycle 4 an additional solvent lobe was detected towards the heel of the well at the same vertical depth as the well. Further investigation has indicated that during injection the solvent may have found a path to this region; however the exact cause has not been determined. HW1 cycle 4 was also characterized by a rapid pressure decline, which is consistent with the solvent chamber extending to a previously unswept region. In cycle 5, the additional lobe was again apparent on the M3 shoot. The bottom-hole pressure declined more slowly than cycle 4 indicating that the new lobe may becoming a more mature chamber. It is unclear if cycle 5 will show improved performance relative to the other cycles at the time of writing the present report.

The seismic results are also consistent with the solvent detection results discussed in Section 5.4. As shown, the solvent chambers overlap all of the OB well bottom-hole locations, with the exception of OB6. The detection of solvent arrival in the perforated wells with ERD sensors (OB1, OB3 and OB5) is reconfirmed by the seismic imaging.

6 Pilot Economics

6.1 Introduction to CSP Pilot Economics

CSP Pilot economics are calculated based the pilot costs and the estimated revenue associated with the produced solution gas, bitumen and solvent. CSP pilot revenue can only be estimated because the CSP pilot is part of Imperial Oil's Cold Lake Production Project and production volumes are blended with Mahihkan plant volumes.

Price data of bitumen and solvent is required to estimate the pilot revenue. The following assumptions apply:

- Bitumen/natural gas pricing is based on actual prices from Imperial Oil's annual 10-K filing
- The propane and flow assurance solvent prices are estimated based on the average prices paid by the CSP pilot in each year for each product respectively

The price information for each reporting year is summarized in Table 40.

6.2 Sales volumes of oil, natural gas and by-products

Annual sales volumes are the basis for the revenue calculation and are given in Table 41.

6.3 Revenue

This section provides the methodology to estimate the pilot revenue.

Revenue is derived from five sources: sale of the produced bitumen, the theoretical sale of produced solution gas, the theoretical sale of recovered propane and the theoretical sale of recovered flow assurance solvent.

A summary of the annual revenues over the project life is given in Table 42.

6.4 Costs

6.4.1 Capital Costs: Drilling, completions, and facilities costs

Annual drilling, completions, facilities costs incurred over the project life are shown in Table 43.

6.4.2 Direct and indirect operating costs

The direct and indirect operating costs are summarized in Table 44.

6.4.3 Injectant costs

Table 45 summarizes the annual injectant costs. Trucking costs associated with transporting each product to site are included.

6.4.4 Total Costs

A summary of the annual costs incurred over the project life is given in Table 46. Annual credits, such as those received from Emissions Reduction Alberta (formerly known as CCEMC), are deducted from the total costs for cash flow calculations, as shown in Table 47.

6.5 Crown royalties

This pilot is part of Imperial Oil's Cold Lake Production Project, with revenue and costs impacting the total Cold Lake payable royalty. An estimation of the impact on the payable royalty is shown in Table 47.

6.6 Cash flow

The annual cash flow is estimated from the annual revenue, credits received, costs and estimated royalties. The following calculation is an example of the cash flow estimate for the year 2018. Similar calculations were performed for each year of the IETP reporting period and are summarized in Table 47.

Revenue 2018 = Bitumen + Solution Gas + Propane + Flow Assurance Solvent
= 638 + 3 + 1,469 + 188
= 2,298 k$

Credits 2018 = ERA Credit (received in February 2019)
= 2,000 k$

Costs 2018 = Drilling & Facilities Costs + Operating Costs + Injectant Costs - ERA Credit
= 0 + 615 + 3,112 - 2,000
= 1,727 k$

Before Royalty = Revenue - Costs
Cash Flow 2018 = 2,298 - 1,727
= 571 k$

Royalties 2018 = Before Royalty Cash Flow x Cold Lake Royalty Rate
= 571 k$ x 31.9%

= 182 k$

Cash Flow 2018 = Revenue - Costs - Royalties
= 2,298 - 1,727 - 182
= 389 k$

6.7 Total Costs and Net Revenue

The cash flow calculation including total costs and revenue is given in Table 47.

6.8 Deviations from budgeted costs

The total budget of the project was 100, 154 k$. The actual cumulative costs for the project over the IETP reporting periods was 92, 243 k$, as shown in Table 46.

Lower solvent costs and operational costs led to the difference between the budgeted and actual costs. Three factors led to the lower solvent costs: (1) the pilot moved towards eliminating flow assurance solvent as a co-injected solvent, (2) flow assurance solvent for utility purposes was reduced and (3) the lower solvent price. Operational cost saving were achieved with a reduction in the required operational support. As the pilot matured operations became smoother since the facility was largely de-bottlenecked during the early pilot life. Also, the cycle length for each well increases which means the process changes more gradually. As a result, operational intervention is less frequent. Lastly, the seismic shoots were completed with cost savings relative to the plan.

7 Facilities

7.1 Description of Major Capital Items

The following subsection describes the major capital items incurred in each year of the project. For reference a photograph of the pilot facilities is shown in Figure 23.

2012

Engineering design of surface facilities was completed by August 2012. Pad equipment skids fabrication began in August 2012, following the completion of detailed design for all mechanical & piping system on the main injection/production pad, as well as, for the production pipeline back to the Mahihkan P4 plant site. The key task of skid fabrication was construction of the solvent injection building, multiphase pump building, and propane transfer skid and associated piping, including:

- Construction and erection of skid frames, walkways, piping and equipment supports
- Construction and installation of piping and valves
- Installation / mounting of packaged equipment on skids
- Surface preparation, painting and insulation of structural steel and piping

Five observation wells were drilled in 2011 with completions finishing in early 2012. These wells are equipped with passive seismic geophones, thermal fiber heaters, and pressure and temperature sensors, in various configurations to assist in monitoring the pilot. This was in addition to OV well 14-18, which was drilled in 2009 and used for selecting the pilot location.

The three pilot horizontal wells were drilled in March 2012. All wells met their directional requirements. Final time was 27.7 days rig release to rig release, 21.0 days spud to rig release. Completions of the horizontal wells began in late 2012, with two problems experienced that have prevented finishing the work.

- On HW-02, problems installing the heater and instrumentation string were experienced. With the heater and instrumentation string at depth, the electrical test of the heater failed. The completion should be finished in late 2013, as the facilities construction schedule permits.
- On HW-03, problems getting a seal on the second casing string packer were experienced. A new packer will be re-run into the well in 2013, as facilities construction permits.

2013

All skids were completed and received on site in the spring of 2013. Major pad facility construction started in February 2013, including the following activities:

- Construction and installation of lease piping and supports
- Pad pipeline construction to bring the pipeline onto the lease and pipeline installation
- Installation of shop fabricated skids on pile foundations
- Installation of equipment and buildings on pile foundations
- Installation of valves
- Pressure testing, inspection and non-destructive examination, draining and flushing of piping

The three horizontal wells began completions in January 2013. This included: installation of the tubing string with attached thermocouples, heater, ERD sensor, and bubble tubes. The installation was completed successfully with full function tests on Horizontal Well #1. At Horizontal Well #2 all tubing and equipment was placed at the final setting position; at this point the final heater function test was not successful and the equipment was retrieved to surface. As Completions ran out its allocated time in 2013, installation of instrumented tubing strings in wells HW2 and HW3 was rescheduled to Q1 2014.

2014

Surface facilities construction was complete by year end of 2013, with only some minor activities such as cleanup, insulation, and hydro-testing to be completed in 1Q 2014. This included major milestones of:

- Fabrication of skids completed and received on site: injection, separator and MCC building
- Construction and installation of equipment, piping, instrumentation and electrical

Facility pre-commissioning started in the third week of February 2014 following the completion of well work and continued until the end of April. Facility was turned over to Cold Lake Operations at the end of April 2014 with final commissioning complete by end of May 2014.

The second phase of the horizontal well completions commenced from January to early February 2014. The objectives were to complete the tubing and instrumentation installation activities at HW2 and HW3 in finalizing the wellbores for pilot operations. HW2 had issues with bottom hole heater functionality, the decision was made to leave tubing with instrumentation attached in well due risk of damage to other instrumentation. All other lines (bubble tubes, ERD sensor, and thermocouple) are functioning properly.

HW3 successfully installed all instrumentation at target depth with full functionality.

Downhole rod insert pumps were installed on all three horizontal wells by early February after all surface facilities and pump jack installations were complete, putting the final equipment in place for production pumping operations. The final status HW completions is summarized in Table 27 and the status of the OB well completions is summarized in Table 28.

2015

The MOP of the underground pipeline was too low for the conditions encountered during pilot operation. After the completion of HW3 cycle 1 in June 2015 the pipeline MOP was re-rated from 1850 to 3675 [kPa]. Effectively, the operating differential pressure, between the pilot site and plant, was increased from approximately 650kPa to 2100kpa. In addition to the pipeline re-rating, the methanol pump was replaced with a higher capacity pump capable of operating at the increased MOP.

Another facility upgrade completed in 2015 was the installation of wellhead heat tracing for HW3. In late November 2015 freezing was experienced at the well-head. The freezing was caused by the lower ambient temperatures and a small section of unheated line near the wellhead. Heat tracing for HW1 and HW2 was installed during Q1 of 2016.

2016

The key facility modifications in Q1 2016:

- A new vent gas compressor with a discharge pressure equal to the re-rated MOP of the pipeline.
- A utility solvent manifold for the independent downhole distribution of flow assurance solvent to multiple wells
- A demulsifying chemical injection system for the test separator to improve the water separation efficiency
- Heat tracing for HW1 and HW2

Multi-well operation began in February 2016. Simultaneous and continuous venting of multiple wells was not possible due to a common venting manifold shared between the HWs. An intermittent venting strategy was applied until casing pressure control valves were installed for each well from September 20 to October 13. Thereafter, continuous venting was achieved for all wells.

The installation of the demulsifying chemical injection system improved the separation of the oil and water phases. However, the separated free-water was not completely dumped from the water leg, causing by-pass into the oil-leg. Installation of a weir was recommended but not logistically possible for the current design. As an alternative, the oil-leg piping was extended into the test separator and set at a pre-determined height above the floor in Q4 2016. The free-water by-pass has been reduced and the reliability of test measurements improved with the oil-leg extension.

2017 and 2018

In 2017 and 2018 there were no major facility modifications.

7.2 Capacity Limitation and Operational Issues

Capacity limitations and operational issues are described below for the active years of the pilot.

2014

Operational issues encountered to date are grouped as either injection system related or production system related. The major facility limitation that could not be sufficiently mitigated and ultimately caused the decision to shut in production was excessive pressure difference in the underground buried trunkline to Mahihkan plant. The factors contributing to this limitation are the relatively low pressure operating ceiling of the pipeline, low temperature leading to increased liquid phase splitting and viscosity, low velocity of flow in the line, and differential velocity between the two hydrocarbon liquid phases which leads to continuous accumulation of the heavier phase. These conditions and subsequent impacts were previously untested and present a challenge unique to CSP. Below is a list of issues that impacted injection and production.

Injection

- Plugging of solvent injection filters (FIL-0051/52) by black colored solids caused intermittent shutdown of injection
- Due off-spec batch of diluent and possibly residual solids from tank construction
- Resolved by switching diluent and cleaning the tank interior

Production

- Wellhead high pressure shutdown due to extreme viscosity heavy liquid phase formation
- Temporary resolution through flushing with diluent
- Test separator (V-0011) oil and water legs plugged with heavy liquid phase on several occasions
- Smaller valves make the separator particularly susceptible to plugging
- Separator design is such that high density heavy liquid phase or asphaltene tends to settle into the water leg and cause frequent flow impairment or plugging
- Flushing with diluent was generally sufficient to unplug flows, however in an extreme case, xylene was needed to first dissolve the heavy hydrocarbon before flushing
- Pad pressure control valve (XV-410) unable to properly actuate or becoming plugged due to heavy liquid phase formation – diluent flush used to remove blockage

- Trunkline to Mahihkan plant shut down due to high pressure differential
- Commissioning water released into pipeline during initial production formed hydrates with propane – resolved through depressurization
- High viscosity heavy liquid phase, insolvent in diluent, caused excessive pressure difference
- Nitrogen gas released into pipeline becomes trapped in pipeline and causes sufficient increase to pressure difference that production is shut in until gas can be flushed out

2015

Injection

- Plugging of the wellbore ICDs during injection (HW3 cycle 2)
- No wellbore treatment prior to injection which allowed late-stage reservoir fluid within the wellbore to contact propane rich solvent during injection
- For future cycles the wellbore is treated prior to injection

Production

- Production rate limited due to pressure differential of the trunkline to Mahihkan plant (HW1 cycle 1 restart)
- Pipeline re-rated to a higher MOP
- Minor plugging of test-separator (V-0011) water leg
- Resolved by flushing with flow assurance solvent
- Degradation of the separation efficiency of the test separator (V-0011)
- Oil leg density fluctuating in response to water dumping
- Low water leg density indicating oil is present
- Installation of demulsifier chemical injection skid planned for Q1 2016
- Wellhead high pressure shutdown due to freezing during low ambient temperatures (November 2015)
- Heat tracing installed on HW3 in December 2015. HW1 and HW2 heat tracing installation planned for Q1 2016
- Low pressure production limited by vent gas system
- Casing gas could not be vented using the MPP system (P-0030/40) after the pipeline was re-rated as the discharge pressure was insufficient
- New gas compressor installation planned for Q1 2016

2016

Injection

- No major limitations or issues were identified

Production

- An intermittent venting strategy was applied during low-pressure operation of HW1 and HW2. Intermittent venting affects the liquid density, liquid rates and the water-cut – ultimately complicating the production allocation process. Continuous steady operation is desirable and therefore casing pressure control valves were installed on each well in September and October of 2016.
- The installation of the demulsifying chemical injection skid improved the test separator efficiency. However, free water by-pass to the oil leg was still observed. Installation of weir was not possible for the current test separator design, so as an alternative the oil-leg piping was extended vertically within the test separator. The vertical pipe has reduced the by-pass of free water into oil-leg; however, the issue has not been fully mitigated.
- HW1 experienced a pump failure on December 1, which was characterized by low wellhead pressure and no liquid delivery. The pump was replaced and the operation resumed on December 5.
- Pipeline pressure was managed with utility flow assurance solvent. During multi-well operation the co-mingled flow may lead to undesirable phase behavior and heavy liquid buildup. Treating with pipeline with flow assurance solvent can mitigate the heavy liquid buildup and restore the pipeline pressure to a normal operating level.

2017

Injection

- No major limitations or issues were identified

Production

- Test separator efficiency remains a challenge for the pilot operation in 2017. Free water by-pass to the oil leg was still observed despite the mitigations described in the 2016 IETP report. The limitations of the test-separator are largely related to the design of the unit and further facility modifications were not attempted in 2017.
- The HW1 pump was replaced four times in 2017. The replacements were required to address poor sealing of the pump. The root cause was determined to be a damaged PSN (pump seating nipple). The final replacement in 2017 implemented an anchor-style pump that was landed above the PSN. The sealing issues were resolved thereafter. The damaged PSN was not specific to CSP.
- The HW2 pump replacement was required due to a pump seizure. This event is not uncommon in rod-pumps and is not specific to CSP.
- Pipeline pressure was managed with utility flow assurance solvent. During multi-well operation the co-mingled flow may lead to undesirable phase behavior and heavy liquid buildup – particularly when early cycle streams are mixed with later cycle streams. Treating with pipeline with flow assurance solvent can mitigate the heavy liquid buildup.

A pipeline plugging event occurred on December 24, 2017. It was fully mitigated in early January 2018.

2018

Injection

- No major limitations or issues were identified

Production

- Test separator efficiency remains a challenge for the pilot operation in 2018. Free water by-pass to the oil leg was still observed despite the mitigations described in the 2016 IETP report. The limitations of the test-separator are largely related to the design of the unit and further facility modifications were not attempted in 2018.

Pilot was challenged in 2018 with pipeline facilities issues. During multi-well operation the co-mingled flow may lead to undesirable phase behavior and heavy liquid buildup. It was expected that multi-well operation during this period would be challenging due to the phase behavior of the co-mingled flow from the three wells. HW1 production at this time was solvent rich, while HW2 and HW3 were late-stage production with higher bitumen cuts. The combination of the early production of HW1 with late stage production of HW2 and HW3 leads to unfavorable phase behavior that must be treated with flow-assurance solvent. Operational interruptions led to periods of low-treatment levels, which consequently deposited heavy liquid within the pipeline and then an eventual plugging. A pipeline plugging event occurred on December 24, 2017, the pipeline was cleaned and production resumed on January 9, 2018.

Production continued until a planned pressure build-up from March 21, 2018 to April 4, 2018, which coincides with the early production period of HW2 cycle 5. The shut-in was longer than typical to mitigate the unfavorable co-mingled phase behavior with HW2 early production. Efforts were made at the time to reduce consumption due to an interruption in shipments of the flow assurance solvent to site. By shutting in HW1, HW2 was the only well producing at the time, thereby reducing the flow assurance solvent requirements. Production resumed on April 4, 2018; however, operational malfunctions led to untreated co-mingled flow within the pipeline. The pipeline was plugged on April 13, 2018. In this instance a more significant work-over was required and pilot operation did not restart until June 13, 2018.

Starting July 13 the pad was shut-in due to pipeline integrity pigging work. The program was scheduled to last approximately one month, but due to complications with cleaning, the program was not completed. The pipeline was cleared when two stuck PIGs were removed on September 9. Pad production restarted on September 27 with no further pipeline issues through remainder of year.

7.3 Surface equipment

Engineering design of the surface facilities was completed by August 2012. The process flow diagrams (PFDs) in Appendix A provide a high-level overview of the surface facilities and are representative of the pilot facilities as of December 31, 2018. Table 48 provides a list of major equipment and their design basis. Below is a description of the major equipment and how they are used in the injection and production system. Please refer to the Process Flow Diagrams (PFDs) in Appendix A.

<u>Solvent Preparation & Blending (Injection)</u>

Propane supplied via truck is stored in two storage vessels, V-0061/62. Propane transfer pumps, P-0061/62, supply liquid propane to the primary injection pumps P-0051/52. Flow assurance solvent is also supplied via truck and is stored in two atmospheric storage tanks, T-0071/72. Transfer pumps, P-0071/72 will boost the pressure for blending with the propane upstream of the static mixer, filters and primary injection pumps. The basket strainer, FIL-0071 is installed on the filling line of diluent tanks removes debris suspended in the diluent supply. The tanks are blanketed by low pressure nitrogen supplied by a LP nitrogen skid.

The blended injection fluid is mixed in an in-line static mixer and then filtered via fine mesh filters (FIL-0051/52) to remove basic sediment. Filtered solvent is routed to the primary injection pumps, P-0051/52 and electric solvent heaters, H-0051/52 before injecting into the wells.

<u>Production System</u>

After each injection cycle is completed, the injected well then starts producing. Production flows through ROV-401 where it is directed either to the electric production fluid heater (H-0054) and subsequently the group production line or to the electric test fluid heater (H-0053) and subsequently the test separator (V-0011). In January of 2016, a demusifying chemical injection skid was installed. The demulsifying agent is injected through a static mixer upstream of the test-separator.

Any gas which may pressure up the casing is vented through the compressor (PK-0031) and re-routed back to the group line. PK-0031 was installed in January 2016 and replaced the MPP system that was originally in place. The common vent gas manifold prevented simultaneous and continuous venting of multiple wells. Casing pressure control valves were installed on the vent line of each well, thereby allowing the wells to operate at independent casing pressures.

Methanol injection into the pipeline is required for hydrate mitigation. The methanol injection system consists of a metering methanol pump (P-0022) and a chemical methanol tank (T-0022).

With the exception of the propane storage and transfer pump area, all site PSVs will discharge to an atmospherically vented pop tank (T-0001). PSV releases from the propane vessels, V-0061/62, and the propane transfer pumps will be discharged to atmosphere through a vent stack located at southwest corner of K-50 pad.

8 Environmental/Regulatory/Compliance

A copy of any approvals mentioned in the following sections, as well as amendments made, can be supplied upon request.

8.1 Regulatory Compliance

The project is operating under ERCB scheme approval 11604. To date, the pilot has been in full compliance, and no regulatory issues have arisen.

8.2 Environmental Considerations

The CSP pilot (construction, operation and reclamation) has been planned to align with the environmental objectives as outlined in the Cold Lake Expansion Project (CLEP) Environmental Impact Assessment (EIA) (Imperial Oil Resources, 1997) as well as with the requirements outlined in operating approval No. 73534-01-00 (as amended) issued by Alberta Environment and Sustainable Resources Development (ESRD) under the Alberta Environmental Protection and Enhancement Act (AEPEA). Numerous other directives and codes of practice have also been reviewed during the planning phase to ensure full compliance. Imperial has an internal database system populated with commitments, requirements and responsibilities as outlined in applicable regulations.

8.3 Air Quality

The CSP pilot has not resulted in any change to air emissions as considered in the EIA discussed previously. Imperial presently conducts air quality monitoring in the Cold Lake Operations (CLO) area outside of regulatory mandates and as a measure of due diligence, Imperial actively monitors the air quality of the CLO area air shed through placement of eleven passive air quality monitoring stations targeting H_2S and SO_2 gas emissions associated with operating CLO facilities. CSP is a sweet oil process and therefore H_2S and SO_2 are not emitted from the current pilot.

8.4 Aquatic Resources

Imperial regularly conducts monitoring programs involving aquatic resources located within the CLO area including surface water, wetlands and groundwater. These programs are regularly expanded and modified as a consequence of field expansion. Imperial presently reports its water diversion volumes in response to corresponding regulations and is in full compliance with water diversion reporting requirements. The addition of the CSP pilot did not generate an increase in water demand.

A Wetland Monitoring Program (Imperial Oil Resources 2005) was implemented in 2006 in which wetland vegetation, water quality and flow dynamics are evaluated on a regular basis. Groundwater monitoring instrumentation is utilized proximal to wetland areas to monitor water flow and drainage performance as well as to monitor water quality/chemistry. Setback requirements associated with environmentally sensitive areas have been maintained in proposed pad and facilities designs.

8.5 Wildlife

Imperial develops its project schedules in a manner consistent with applicable regulations. Environmental aspects are considered and evaluated during the pre-construction planning phase of all Cold Lake projects with special attention paid to wildlife habitat and movement issues. The CSP development was conducted with the objective of minimizing disturbance to wildlife habitat and movement.

During production, Imperial personnel adhere to the Wildlife Mitigation and Monitoring Plan which outlines specific actions and responsibilities designed to reduce operations-related risks to wildlife and wildlife habitat in the CLO area.

Reclamation plans are developed and implemented with particular attention paid to returning the land to an equivalent land capability. Wildlife use of reclaimed sites is a key aspect of reclamation success and will be monitored through the Cold Lake Reclamation Monitoring Program.

8.6 Noise

Through direct consultation with regulators and other stakeholders, Imperial has developed a noise prediction model to meet the requirements of ERCB Directive 038 (ERCB 2007). The entire Cold Lake Expansion Project has shown to be significantly below the allowable p sound level (PSL).

8.7 Reclamation

The CSP pilot decommissioning and reclamation activities will be addressed in accordance with EPEA Approval 73534-0-00, as amended.

9 Summary – Operating Plan

9.1 Project schedule

The project schedule is categorized into pre- and post-start up activities. The pre-start up project schedule is shown in Figure 1 and the post-start up pilot progress is shown in Figure 2.

In the post-start up schedule, the injection and production cycles are identified along with key activities during periods of pilot downtime. The pilot operations timeline is divided into an early, middle and late-stage activities, as indicated. The early phase is from the start-up in May 2014 to August 2015; the middle phase is from September 2015 to November 2016; and the last stage is from December 2016 to June 2018. The progress during each phase is described below:

9.1.1 Pre-start up Phase

The pre-start up project schedule is shown in Figure 1. As shown, the pre-start up activities include detailed engineering, material fabrication, facility construction and facility commissioning. The details of the construction and manufacturing were described previously in Section 7.1

9.1.2 Early Pilot Operations Phase

The pilot was started in May 2014 with HW3 coming online. A key objective of the early pilot phase was to assess the operability of the facility. Significant operational learnings were developed during this period. Two flow assurance challenges led to prolonged shut-ins during HW3 cycle 1 production, as shown in Figure 2. In the first instance, inadequate methanol treatment and residual water from commissioning activates led to hydrate formation within the production pipeline in June 2014. The hydrate removal procedure ensued and the hydrate was successfully removed. Production then continued for a brief period in August 2014, but was subsequently shut-in due to facility plugging with heavy liquid production. Diluent had been selected as the co-injection and utility solvent for the pilot. However, the resulting phase behavior was found to be more severe than anticipated through the laboratory studies. As such, the pilot was shut-in in September 2014, so that debottlenecking studies could be completed prior to continuing operation. During the 8 month shut-in period, a new flow assurance solvent was sourced and additional equipment modifications were planned.

HW3 was resumed in January 2015. Cycles 1 and 2 were completed by September 2015, marking the end of the early pilot phase.

9.1.3 Mid-Pilot Operations Phase

The mid-pilot phase began in September 2015. The focus of this period was on achieving stable operation of all three wells. Facility modifications were completed for multi-well operation in January of 2016. Thereafter, HW3 resumed cycle 3 production while HW1 and HW2 were started in February and May 2016, respectively. The remainder of 2016 would progress HW3 to the end of cycle 4, while HW1 and HW2 would continue cycle 3 production through the year end. The mid-pilot stage was significant progress for the CSP pilot. High quality surveillance data was measured for all three wells over multiple cycles. The initial struggles for the pilot facility were overcome and smooth and stable operation was achieved.

9.1.4 Late Pilot Operations Phase

The late stage of the pilot was focused on continued stable operation and the additional collection of high quality surveillance data. A key deliverable was to demonstrate the repeatability of the reservoir performance metrics. More specifically, the larger cycles tested during this period are influential to the cumulative performance metrics of the overall process. Therefore, the capturing of the cycle 4 and cycle 5 performance for each well was necessary to understand the larger cycle performance. Form a surveillance perspective the focus was the on the successful execution and interpretation of the three 4D seismic shoots. By the end of the Late Pilot phase HW3 had progressed into cycle 6, while HW1 and HW2 were progressing cycle 5.

The pilot will continue to operate past the current reporting period. The focus of the pilot will shift from testing the base CSP technology as described herein to testing CSP enhancement concepts.

9.2 Optimization Strategies

Optimization or improvements are documented below for each year of the pilot operation.

2014

The pilot will test the high-aromatics catalytic distillate as the primary flow assurance solvent to replace diluent. If successful, it will replace diluent both for surface flow assurance and subsurface injection with propane.

2015

In 2015, production on HW3 was restarted. Initially, a conservative approach was taken with regards to the use of flow assurance solvent in order to maintain stable operation of the pilot. As the year progressed and operational experience developed the conservative approach transitioned to a more optimized approach. Once the facility modifications planned for Q1 2016 are complete the facility will better equipped to further test the operational boundaries of the

CSP process. In particular, limiting the use of flow assurance solvent, methanol and downhole heating are planned for 2016. In fact, there is a unique opportunity to test the effects of downhole heating with HW2. Unlike HW1 and HW3, HW2 is not equipped with active downhole heaters. Also, the requirement for co-injected flow assurance solvent could be tested with HW1 or HW2. Selectively using flow assurance solvent to address symptoms of heavy liquids, opposed to continuously flowing, would be a more optimized mode of operation. Eliminating the use of flow assurance solvent downhole would significantly streamline the sample analysis process and further optimize the pilot surveillance. Lastly, with the installation of the new vent gas compression system in Q1 of 2016, the pilot will be able to operate wells at lower bottom-hole pressures. Testing the well performance with low pressure production is an optimization goal of 2016.

2016

In 2016, the CSP pilot focussed on operational stability as the pilot transitioned to a multi-well operation. Initially, a conservative approach was applied to the use of flow assurance solvent, methanol and downhole heating to ensure operational stability. As the pilot progressed through the first cycles of HW1 and HW2 the focus shifted to limiting the use of downhole flow assurance solvent. Selective use of downhole flow assurance resulted in improvements to production allocation and sample analysis program. Continuous delivery of flow assurance solvent to the pipeline was only required during specific periods when the co-mingled flow of multiple wells led to undesirable heavy liquid build up in the pipeline.

HW2 was brought online and tested two different operational variables. The solvent composition was changed to 100% propane injection, thereby eliminating downhole co-injection of the flow assurance solvent. Also, HW2 does not have active downhole heaters, so the operation of HW2 had to proceed without additional downhole heating. To date, the performance of HW2 is similar to HW1 and HW3 suggesting that HW2 strategy is a more optimized approach to operate CSP. The performance of HW2 was one factor that led to a change of the injectant composition for HW3 cycle 5. Eliminating flow assurance solvent from HW1 is a possibility for cycle 4 in Q1 2017.

Lastly, the installation of the new vent gas compression system allowed the wells to be operated at lower bottom-hole pressures. HW1 and HW2 realized the benefits of low pressure operation which aimed to extend the cycle life and improve the hydrocarbon recovery. As described previously, the pressure support experienced on HW3 limited the low-pressure operation range of HW3. Further testing of low-pressure operation is planned for 2017. In particular, a mini-blowdown is planned for HW2 in Q4 of 2017.

2017

In 2017, the CSP pilot focussed on operational stability of the larger cycle operation. A late-cycle low pressure mini-blow down was attempted with HW2. The test was terminated prematurely due to a PAD shut-in and pipeline work-over. Further testing of low-pressure operation is planned for 2018.

2018

In 2018, operations were interrupted due to pipeline facilities issues, as described in Section 7.2. After returning the pilot to steady state operations, the focus was on the successful operation of the current cycles.

9.3 Salvage update

Currently, no plans to salvage any of the equipment on site have been developed.

10 Interpretations and Conclusions

10.1 Overall Performance Assessment

The field testing or piloting of the technology represents an important contribution to technology development as it bridges the gap from lab-scale experiments to full field deployment. The overall goal of the CSP pilot project was to test the technology at a representative field scale with the intention of addressing uncertainty that cannot be delineated at the lab scale or with numerical simulation. The specific pilot goals are given below:

- Safely acquire high-quality data to allow for definitive interpretation of pilot results
- Provide sufficient information to assess whether CSP is a commercially viable recovery process at Cold Lake
- Gain necessary operation experience with CSP to enable future design of a cost-effective commercial application

The Project Outcomes are summarized below with respect to the pilot goals given above:

- Safely acquired high-quality data to allow for definitive interpretation of pilot results.
    - The pilot achieved high quality data across its surveillance plan such that the results could be interpreted for technical assessments of the CSP process. Examples include the successful metering of the injection and production fluids that were validated with a comprehensive sample analysis program. Sub-surface surveillance was successful in detecting and visualizing the solvent conformance for all three wells. In addition learnings were gained regarding the usefulness of the measurement instruments.

- Provide sufficient information to assess whether CSP is a commercially viable recovery process at Cold Lake
    - High-quality production data (rates, pressure, etc.) and sample data (fluid properties such as density, viscosity, and composition) provided a deep understanding of the process. The pilot results were then the basis for a predictive simulation model development. The model is calibrated to the pilot results and then used to extrapolate the performance of CSP for a commercial development.

- Gain necessary operation experience with CSP to enable future design of a cost-effective commercial application
    - The pilot provided valuable learnings from an Operational & Surveillance perspective. The early pilot phase had challenges that were overcome with novel solutions. Encountering these challenges at the pilot project has led to a

technology that is commercially viable not only from a reservoir perspective but also operationally. In addition, important learnings have been obtained regarding the challenging phase behavior of the process, which will directly influence future commercial design choices.

The CSP pilot was successful in accomplishing the pre-project goals. The CSP technology has been deemed commercially viable through Imperial's internal technology development system. The GHG reductions that are inherent to the process will be realized as the technology is deployed commercially.

10.2 Difficulties Encountered

Difficulties encountered during the pilot were largely related to the production pipeline design and the flow assurance solvent selection. Significant operational learnings were developed during the early phase of the pilot, as described in Section 9.1.2. Continuous methanol treatment of the produced fluid was required to prevent hydrate formation within the pipeline. Furthermore, during certain periods of production (depending on the production composition) the continuous use of the flow-assurance solvent, opposed to diluent, was required to prevent heavy liquid plugging. Future applications of CSP would look to avoid hydrate and heavy liquid formation with a different production pipeline design.

10.3 Technical and Economic Viability

The CSP pilot, in combination with the previous field trials, laboratory work and simulation development, has demonstrated the technical viability of the process. High quality data was acquired which was then the basis for the development of a predictive simulation model. Showstoppers were not identified during the pilot which could generally be related to low performance indicators, such as the bitumen and solvent recovery levels.

The predictive simulation model is used to generate long term CSP flow streams and forecast the performance of the commercial development. Imperial is continuing to evaluate the feasibility of a commercial development and is continuing to evaluate the economic viability of the process. Section 10.5.2 provides a description of a commercial concept and additional information regarding the widespread application of CSP technology.

The commercial deployment of CSP considers many factors. For context some of the considerations are discussed below.

CSP can be applied to any resource that is recoverable by CSS, with limitations on top gas, bottom water and there must be a competent top seal. In addition, CSP can economically target lower quality resource that is either too lean and/or too thin to yield favourable steam-to-oil ratios (SOR) when deploying traditional steam-based processes. Since CSP is a non-thermal process, it is robust over a wide range of resource quality.

The first application of the CSP technology will develop additional resource within Imperial's Cold Lake Development. The resource is characterized as thick-lean with a thickness of approximately 30 [m] and bitumen saturations ranging from 6 to 8 wt%. The value of CSP is clear in that low quality resource can be economically developed, while also providing an industry-wide step change in the reduction of GHG emissions intensity.

The first application of CSP bridges the gap between the field pilot and widespread development of CSP at the commercial scale. The present field pilot has demonstrated the viability of the technology to recover bitumen at performance levels required to be competitive at the commercial scale. The first commercial application will also provide additional learnings in number of areas, not limited to the reservoir geology, wellbore design, and surface facility design. Operational learnings will be key to the commercial project and will lead to future efficiencies and long term cost-competitiveness.

The present application of CSP not only paves the way for wide-spread application but also opens the door for the application of enhancements to the base CSP process. Imperial has developed improvements to the base concept that reduce the solvent required, improve the bitumen recovery, accelerate and maximize the resource recovery. As such, the first application of this breakthrough technology will only serve to improve upon a process with significant benefits in its base form.

10.4 Overall Effect on Gas/Bitumen Recovery

As described in Section 2.4, the ratio of the produced bitumen during the pilot life relative to the bitumen-in-place in the pilot area is not representative of the recovery factor of a commercial development. The wells have been purposefully spaced farther apart in the pilot to avoid interaction, which is different than in a commercial project. The bitumen recovery of the CSP base process is estimated to be between 20-50% depending on a number of factors, such as the well spacing, resource thickness, resource quality and terminal cut-off of the individual wells.

10.5 Future expansion or commercial field application

The CSP pilot has tested the base CSP process. Like any technology there are areas of improvement in which the process can be enhanced. Imperial has an active CSP enhancement research program. It is recommended that pilot operation continue with the focus shifting from the base process to enhancement concepts.

10.5.1 Next Steps for Commercial Deployment

The commercial readiness of the CSP technology has been demonstrated through the integrated research program at Imperial. Imperial's development team is currently progressing the first commercial concept. The first commercial concept is described below and further widespread adoption of the technology is described in Section 10.5.2.

The first commercial concept is a 10kbd facility with an initial single pad design that will see a second productivity maintenance pad come online about 4 years after the first. It will be located adjacent to the pilot site within Imperial's Cold Lake lease. Each pad will consist of up to 30 wells, the propane will be trucked to site, and produced fluids will be piped to the Mahihkan plant in Cold Lake for processing. The performance of the commercial development will be evaluated technically using key performance metrics similar to those used to evaluate the pilot performance, examples include: the bitumen and solvent recovery and the oil-to-solvent ratio.

The commercial concept will aim to leverage the learnings of the CSP pilot. Many decisions related the process will remain unchanged. For example: propane is the solvent of choice for the first commercial application. It is selected to balance both the technical requirements of CSP and the commercial applicability. Propane is a relatively good viscosity reducing agent and thereby sufficiently mobilizes the native bitumen. The vapor pressure is also favorable allowing gas-drive to occur after the post injection pressure-drive. From the commercial applicability perspective propane is abundantly available and inexpensive compared other solvents.

The key milestones are shown below with key start dates. The project is progressed using a staged-gate system. At each successful gate the project is refined such that the financial commitment can be increased, eventually reaching a full-funding commitment. In 2018 preliminary engineering studies were underway which focus on the refinement of the commercial concept. A full funding decision is expected to occur in 2020. Thereafter, capital expenditures are related to the detailed design and engineering, facilities construction, drilling and the required commissioning. Start-up of the facility occurs in 2023 and the facility will continue to operate for approximately 18 years. The dates and timelines provided herein are best estimates at the present time, but are subject to change based on the external business conditions and internal priorities.

2018	Preliminary Engineering
2020	Detailed Design and Engineering
2020	Construction and Drilling
2021	Construction of the surface facilities and Commissioning
2023	Start-up

10.5.2 Widespread deployment of the technology

In the success case of the first commercial application, CSP will be an economically competitive alternative to CSS and SAGD for the bulk of Alberta's bitumen resources that require an in-situ recovery process.

CSP can be applied anywhere CSS is applicable, such as Cold Lake, provided there is no significant top gas or bottom water and there is a reasonable top seal to the reservoir. Additionally, it is expected that the technology will enable the efficient recovery of resources that are too thin or low in bitumen saturation for thermal processes to be economic. Within Imperial's lease holdings in Alberta, CSP is targeting several billion bbls of resource in both Athabasca and Cold Lake, predominately thin or lower bitumen saturation reservoir. Expected recovery from those resources is more than 1 billion bbls. More broadly, Alberta has 785 billion bbls of bitumen in reservoirs with an average bitumen saturation of between 6 and 8 wt% or with an average pay less than 10 metres thick. These reservoirs are largely considered uneconomic to recover using current thermal processes, yet are targetable by CSP.

The value proposition of CSP is clear in that bitumen can be delivered to market with a significantly reduced environmental footprint. The pace of the commercial development of CSP is dependent on factors including first commercial application results, oil price, availability of resources and other opportunities.

The key uptake potential is that CSP allows growth of the oil sands through bitumen production from lean reservoirs where no other technology exists, while resulting in a significant reduction in greenhouse gas emissions.

Figures

Figure 1: Pre-start up pilot schedule

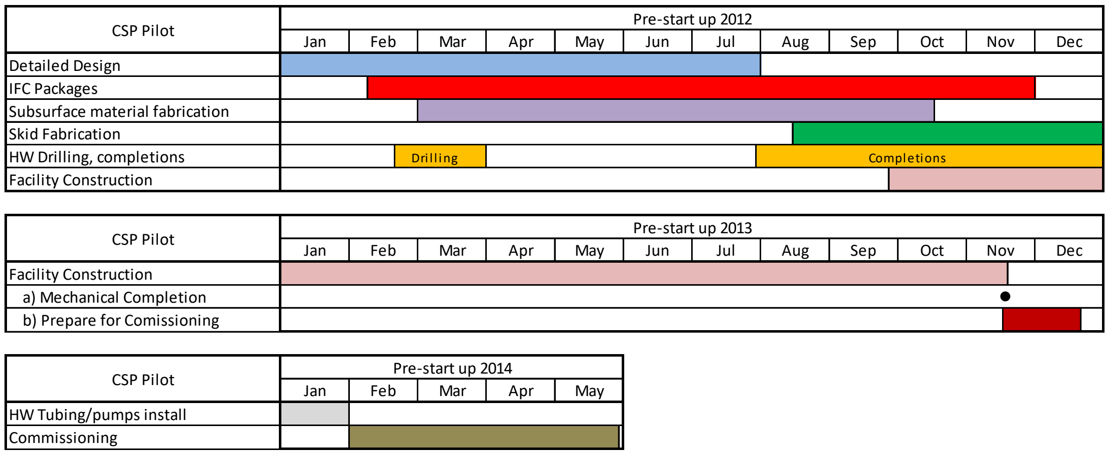


Figure 2: Post-start up pilot schedule

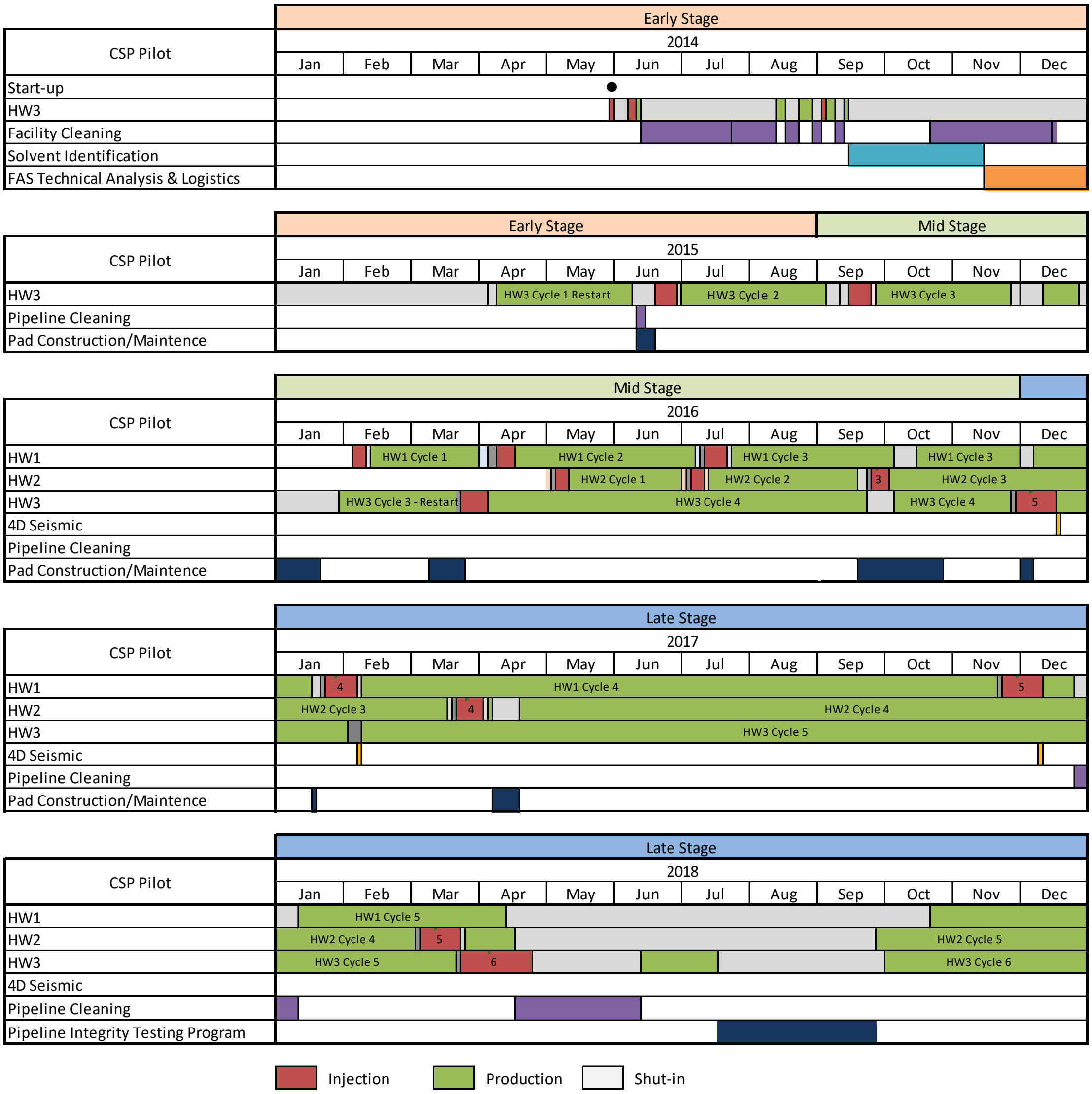


Figure 3: SHW Pilot Production Profile – IETP Proposal 2011

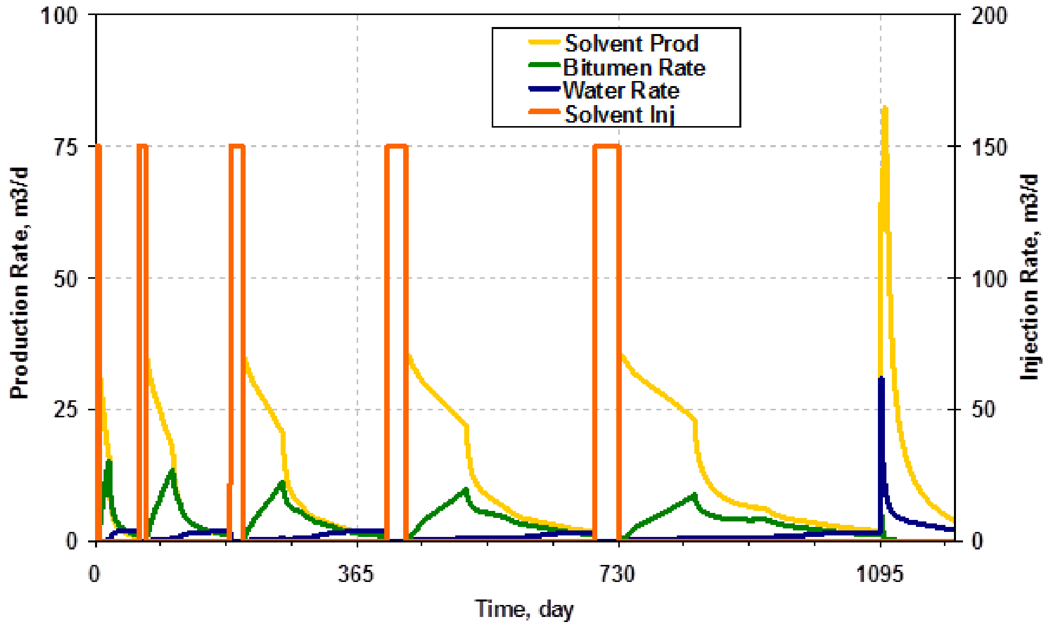


Figure 4: Well Layout

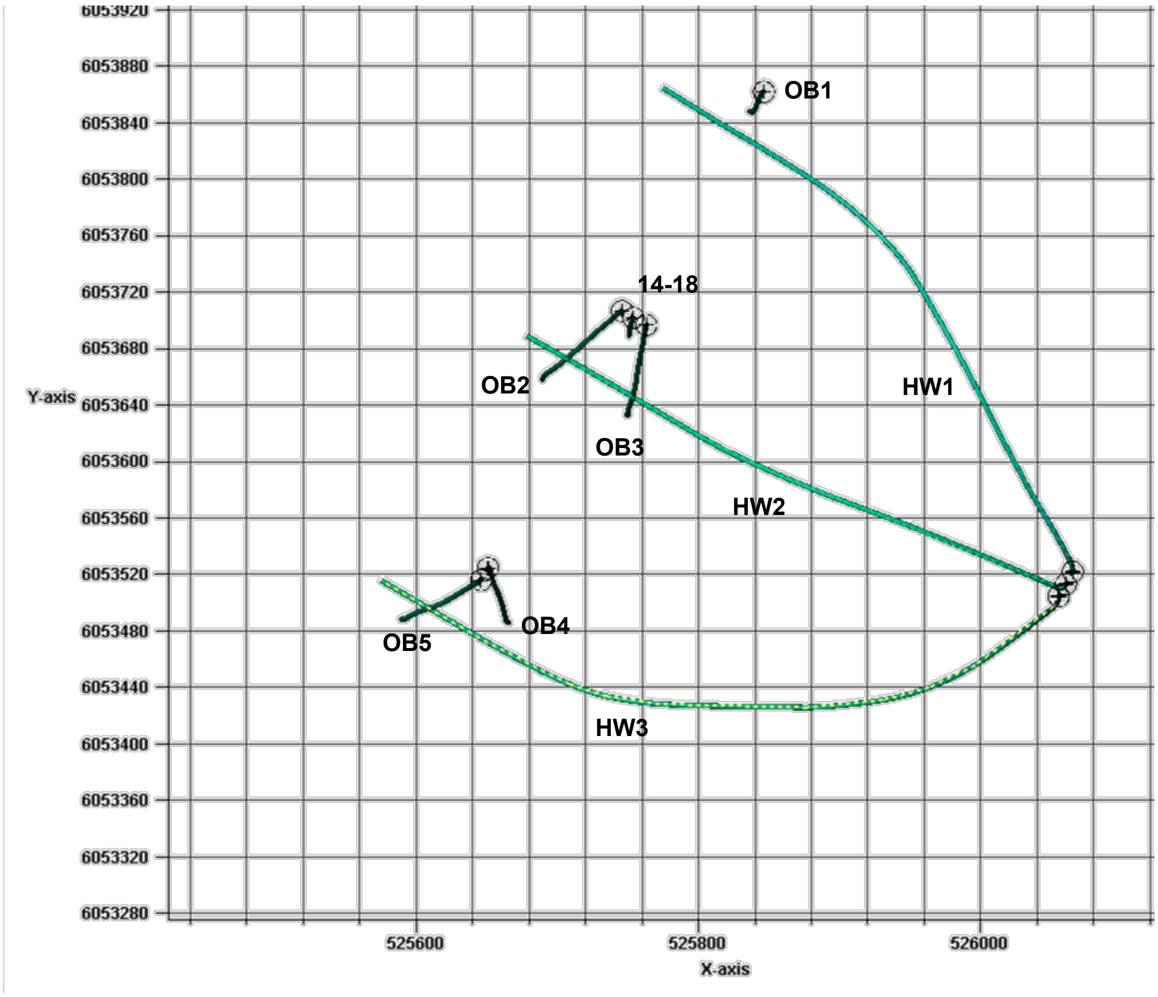


Figure 5: Surface Facility and Pad Locations

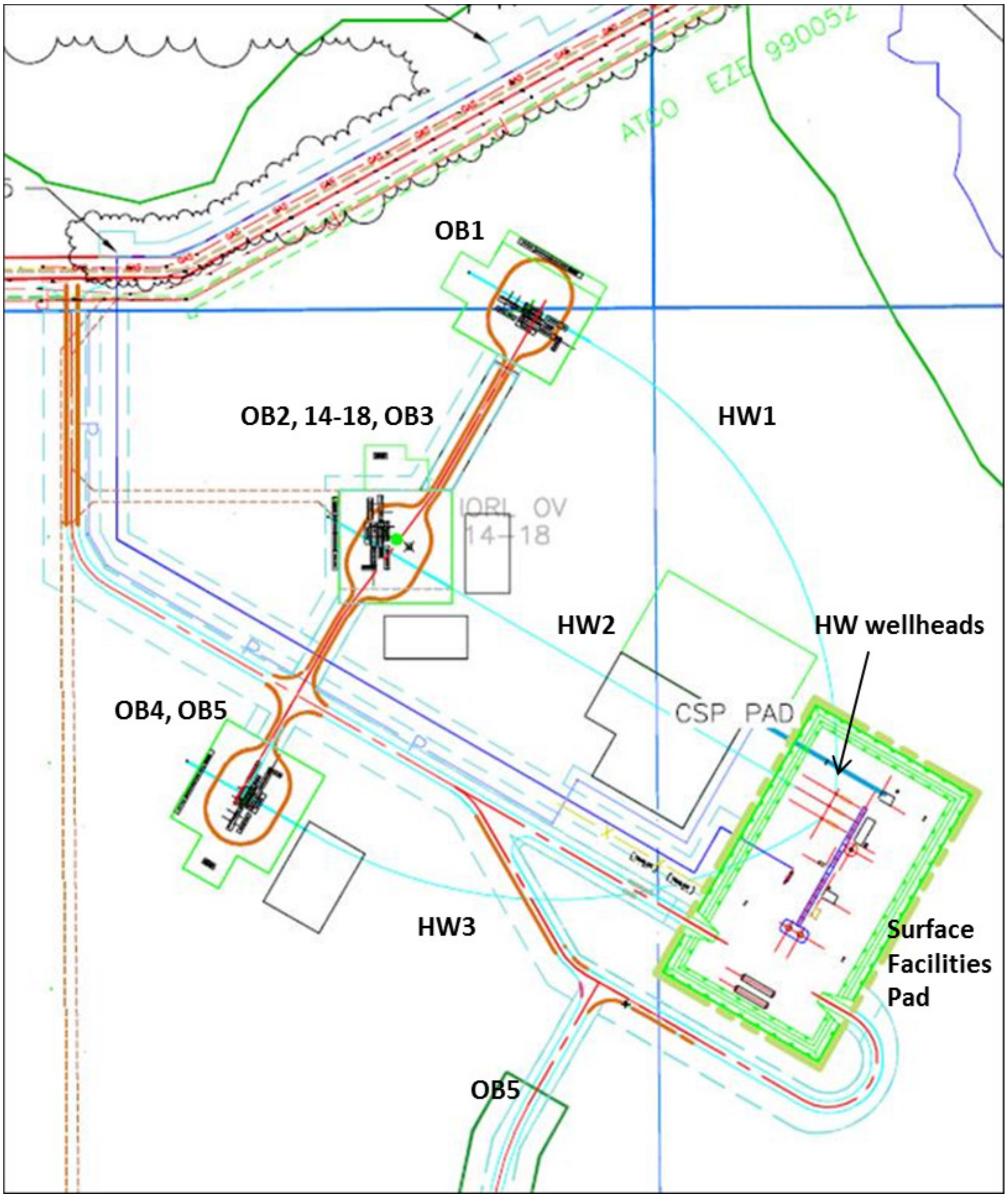
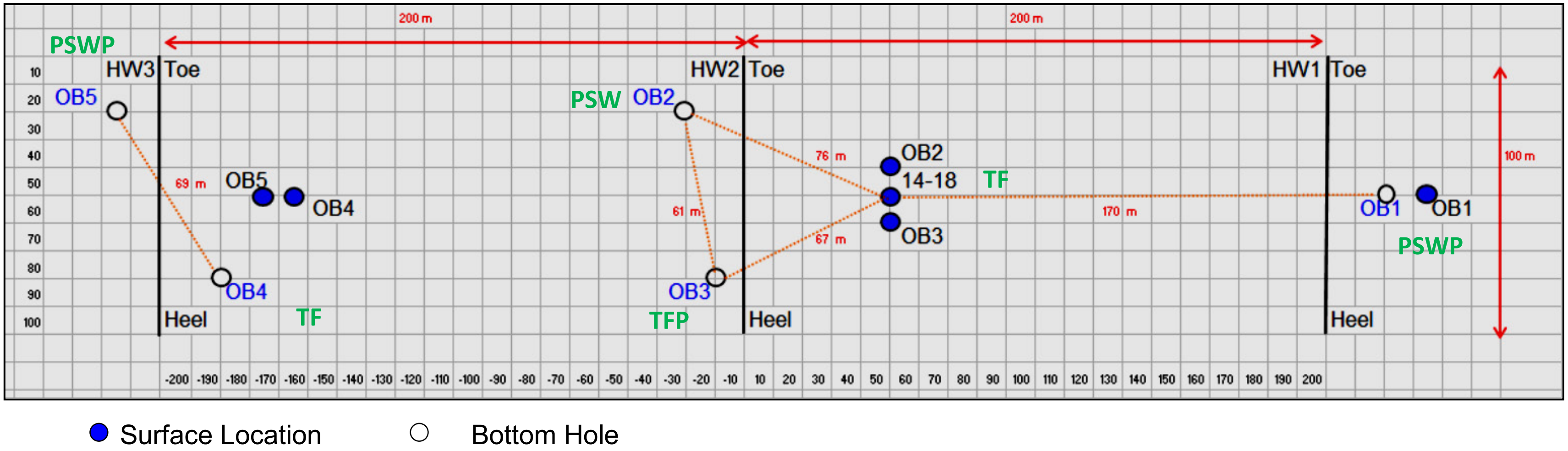


Figure 6: OB Wells Location and Surveillance Instrumentation



PSW – Passive Seismic Well (with evacuated tubing)

PSWP – Hybrid PSW (Passive Seismic Well with BHP measurement)

TF – Thermo Fiber Well with Heater

TFP – Thermo Fiber Well with Heater and BHP measurement

Figure 7: CSP Horizontal Well Schematic

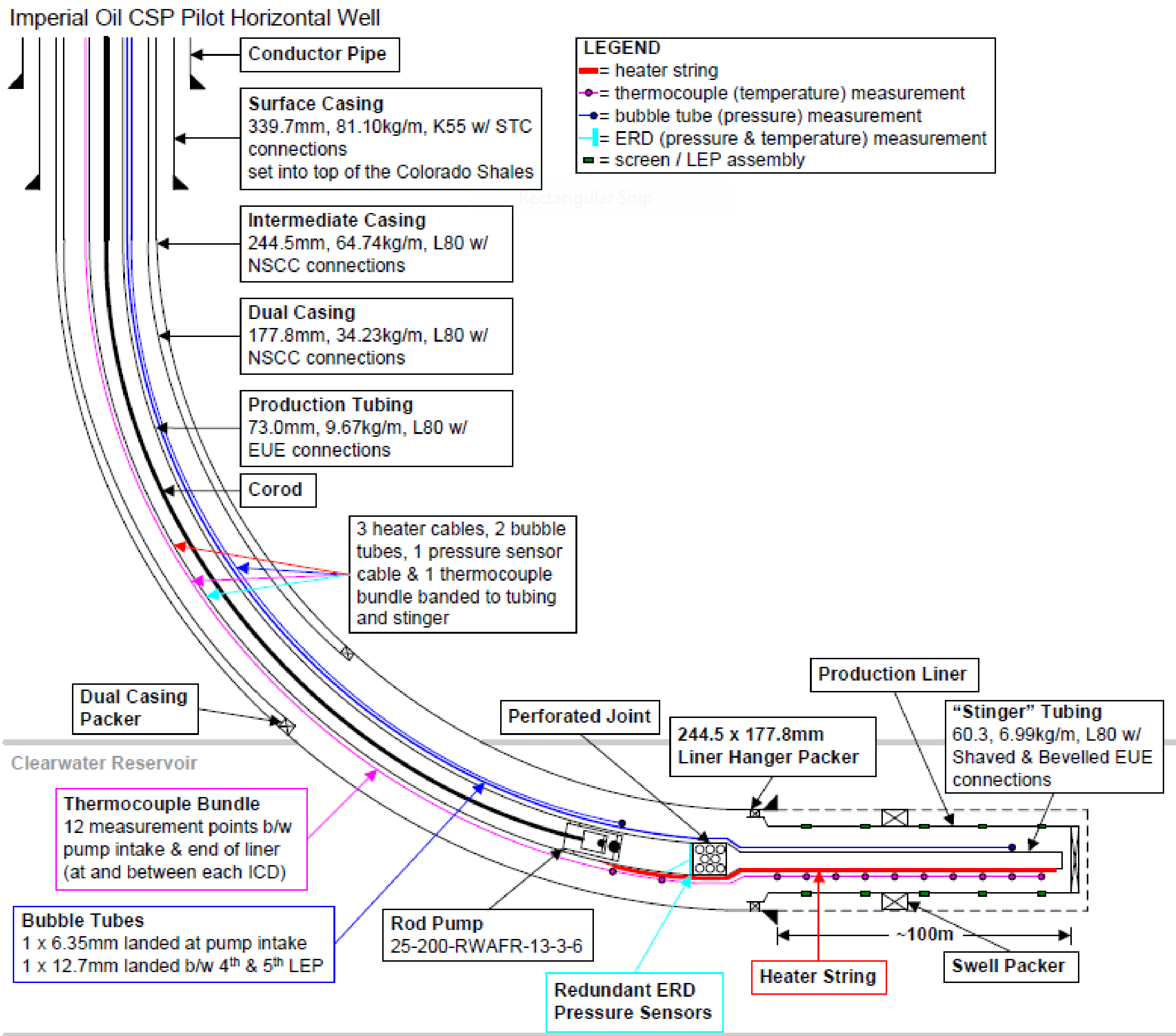


Figure 8: Characteristic Curve Shapes of CSP Components in C30+

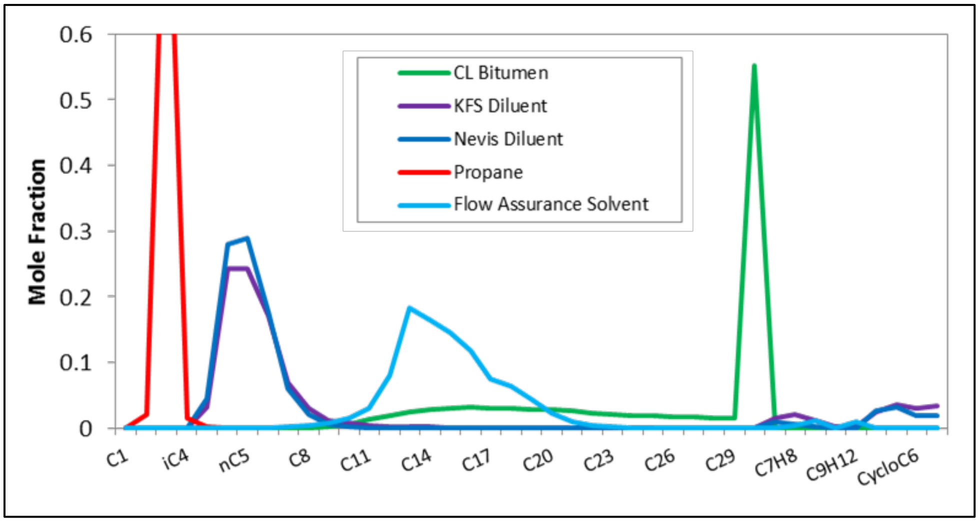


Figure 9: Pressure Comparison between simulation and pilot

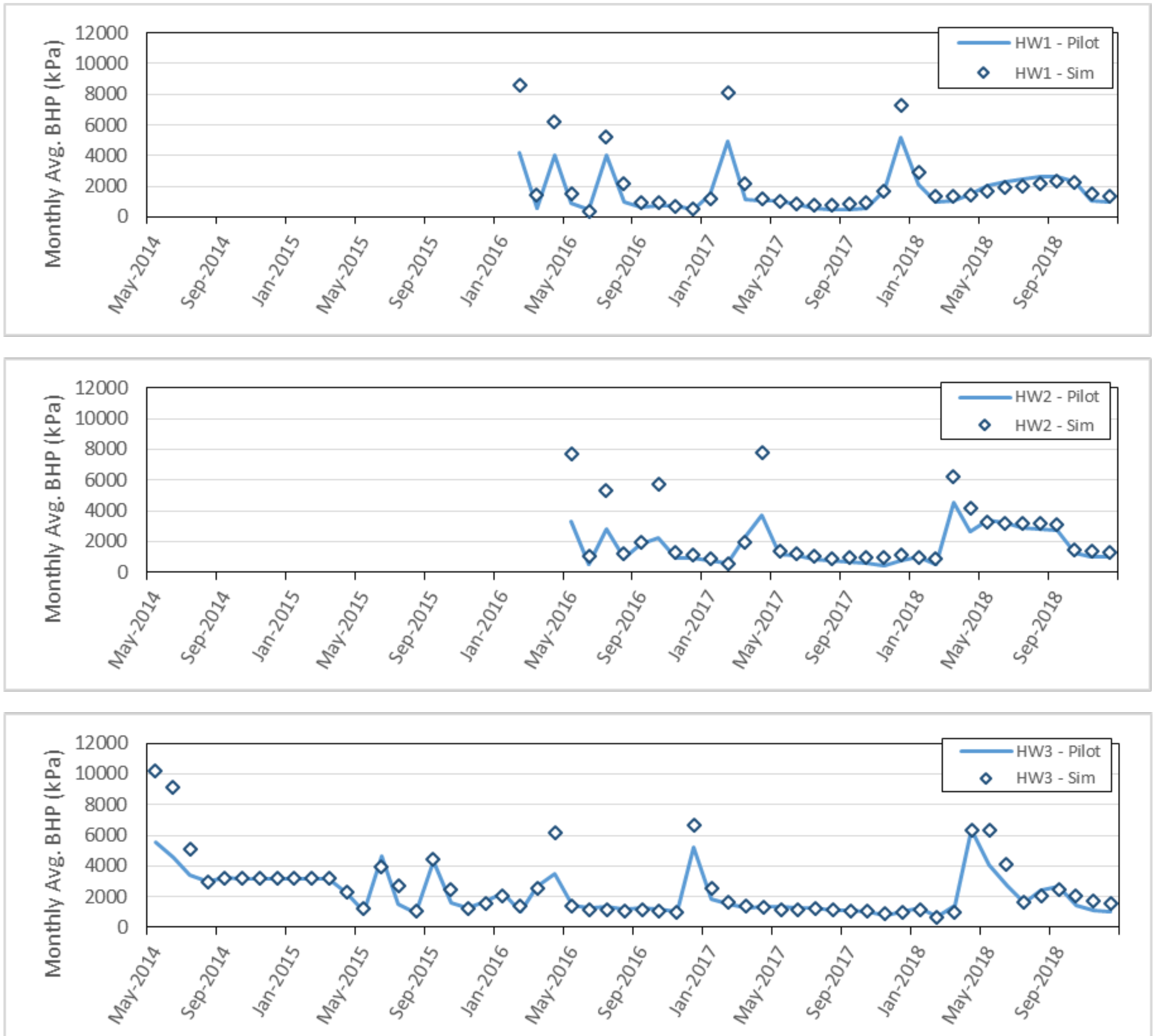


Figure 10: Log Cross Section of Pilot Area through OB Wells

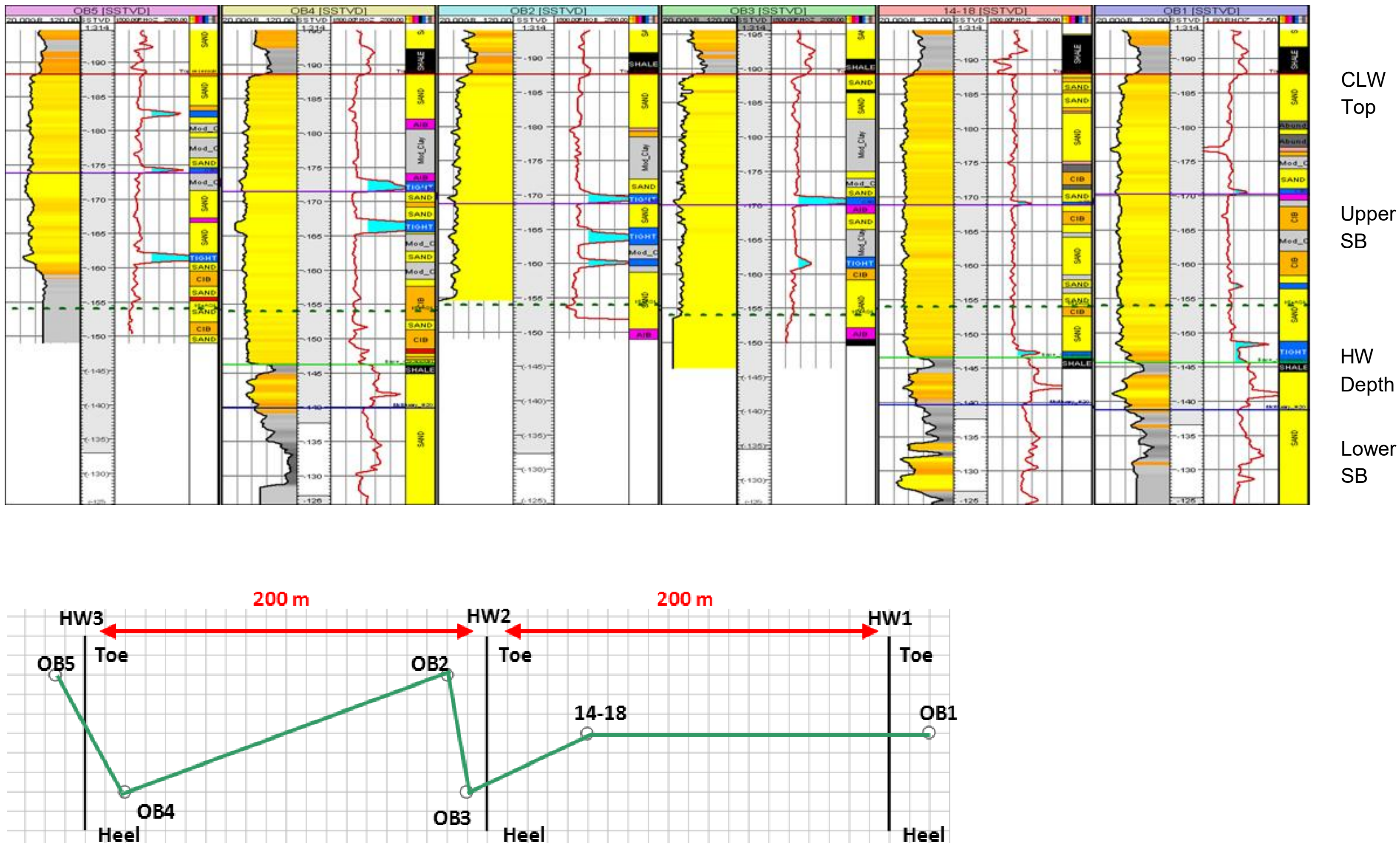


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Figure 11: Cross-well Borehole Tomography Lines

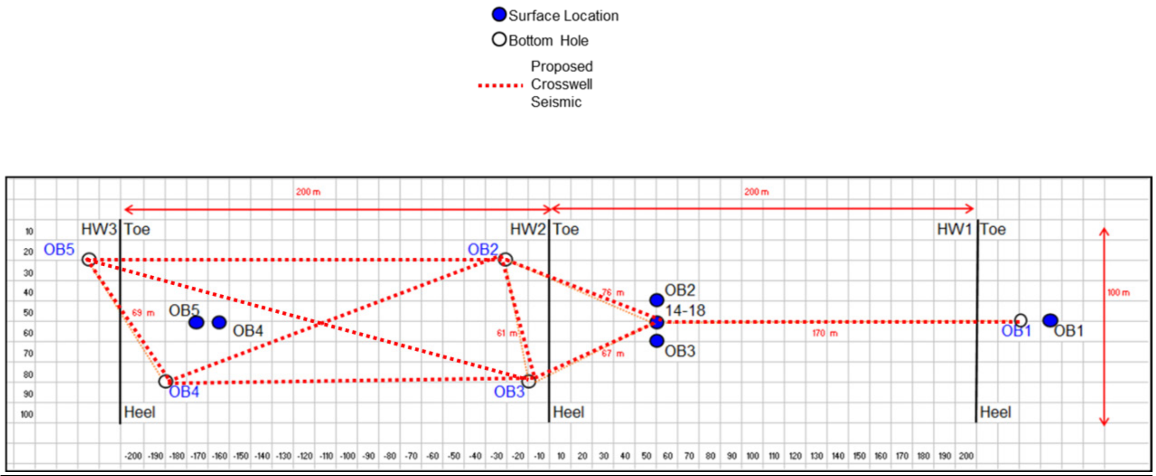
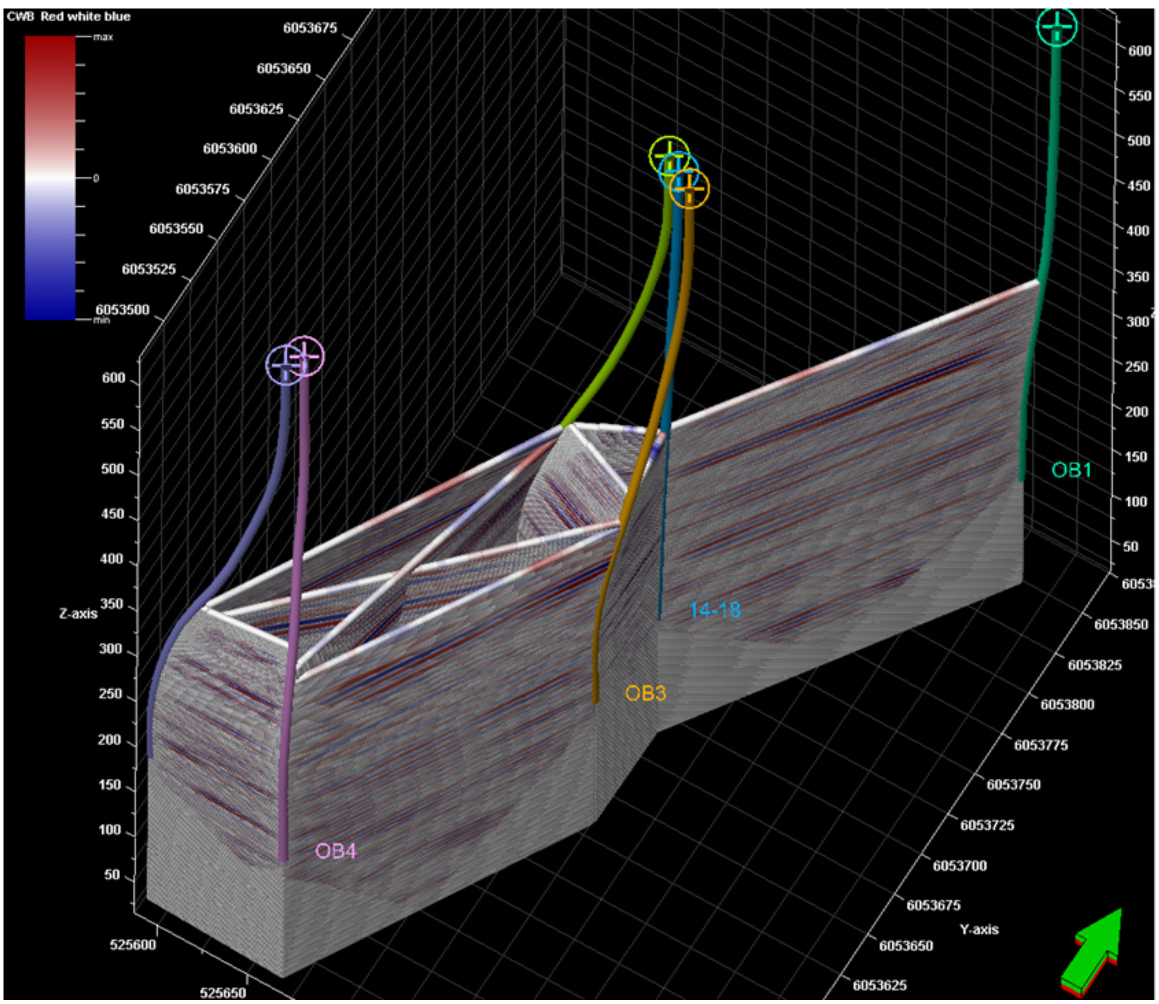


Figure 12: Results of Base Cross-Well Borehole Tomography



<u>Figure 13: Representative ZTrac Survey – OB1 to 14-18</u>

(Clearwater Formation shown by orange bar)

OB1 **14-18**

ILD **ILD**

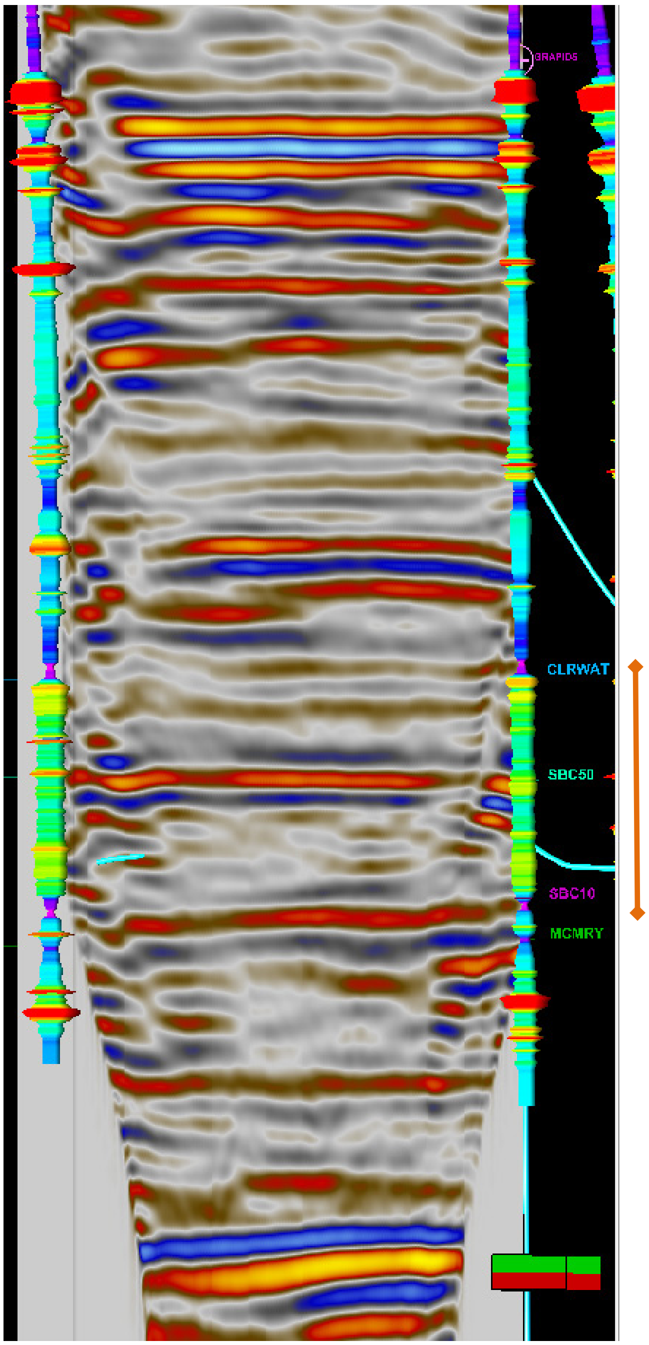


Figure 14: Representative ZTrac Survey – OB1 to 14-18 Clearwater Only

(Clearwater Formation shown by orange bar)

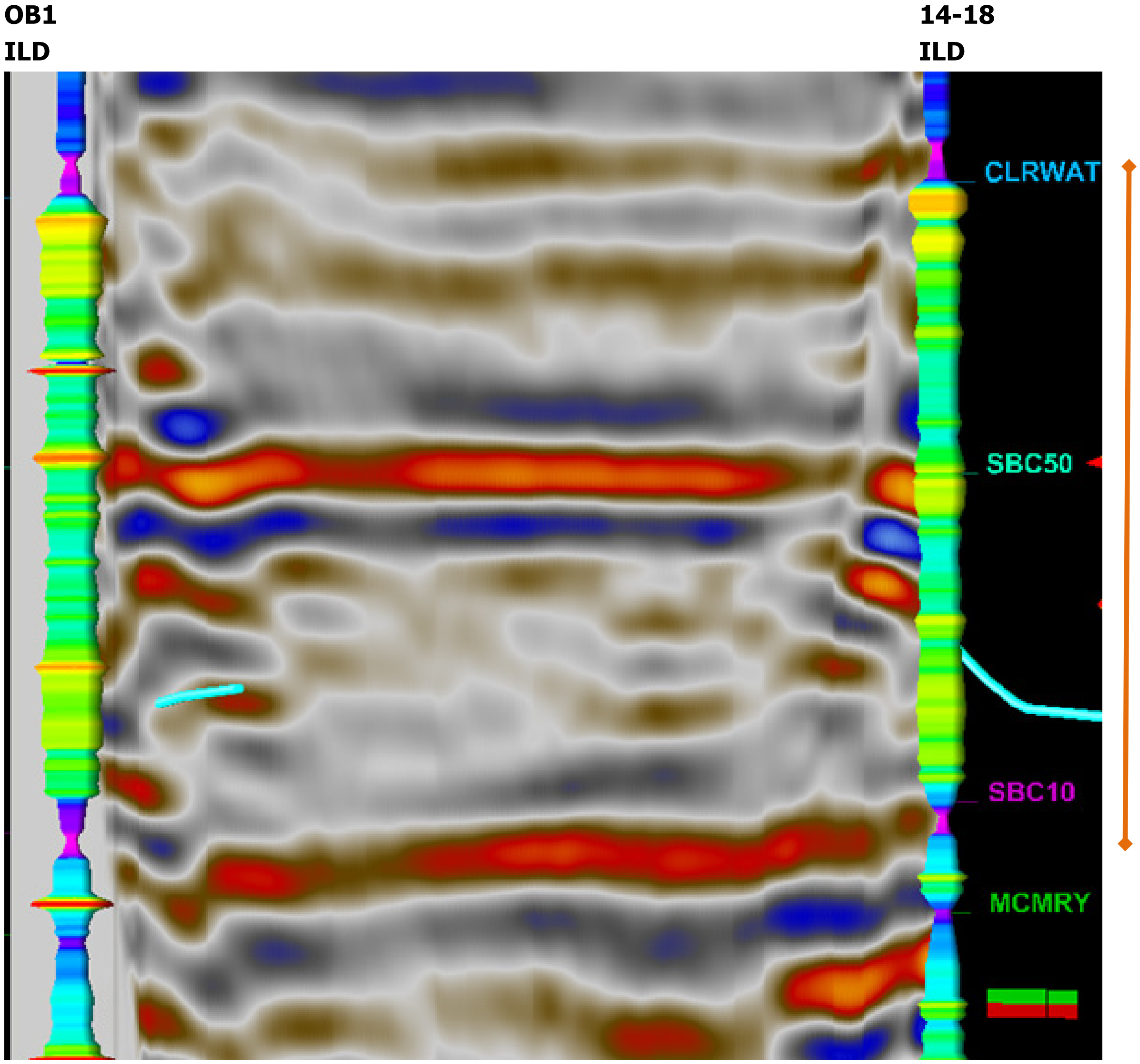


Figure 15: Representative Piezo Electric Survey – OB2 to OB3

(Clearwater Formation shown by orange bar)

OB2 **OB3**
ILD **ILD**

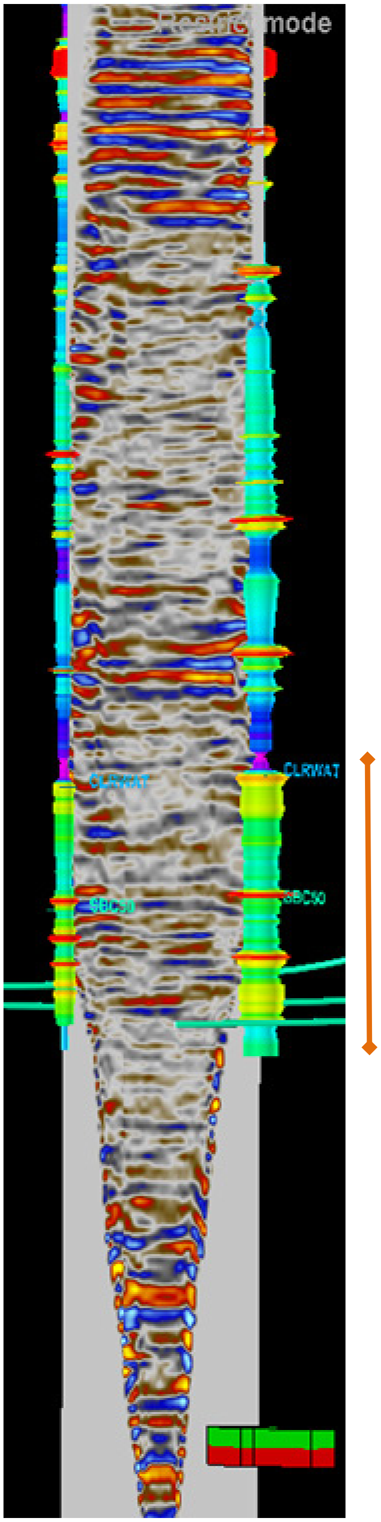


Figure 16: Representative Piezo Electric Survey – OB2 to OB3 Clearwater Only

(Clearwater Formation shown by orange bar)

OB-2
ILD

OB-3
ILD

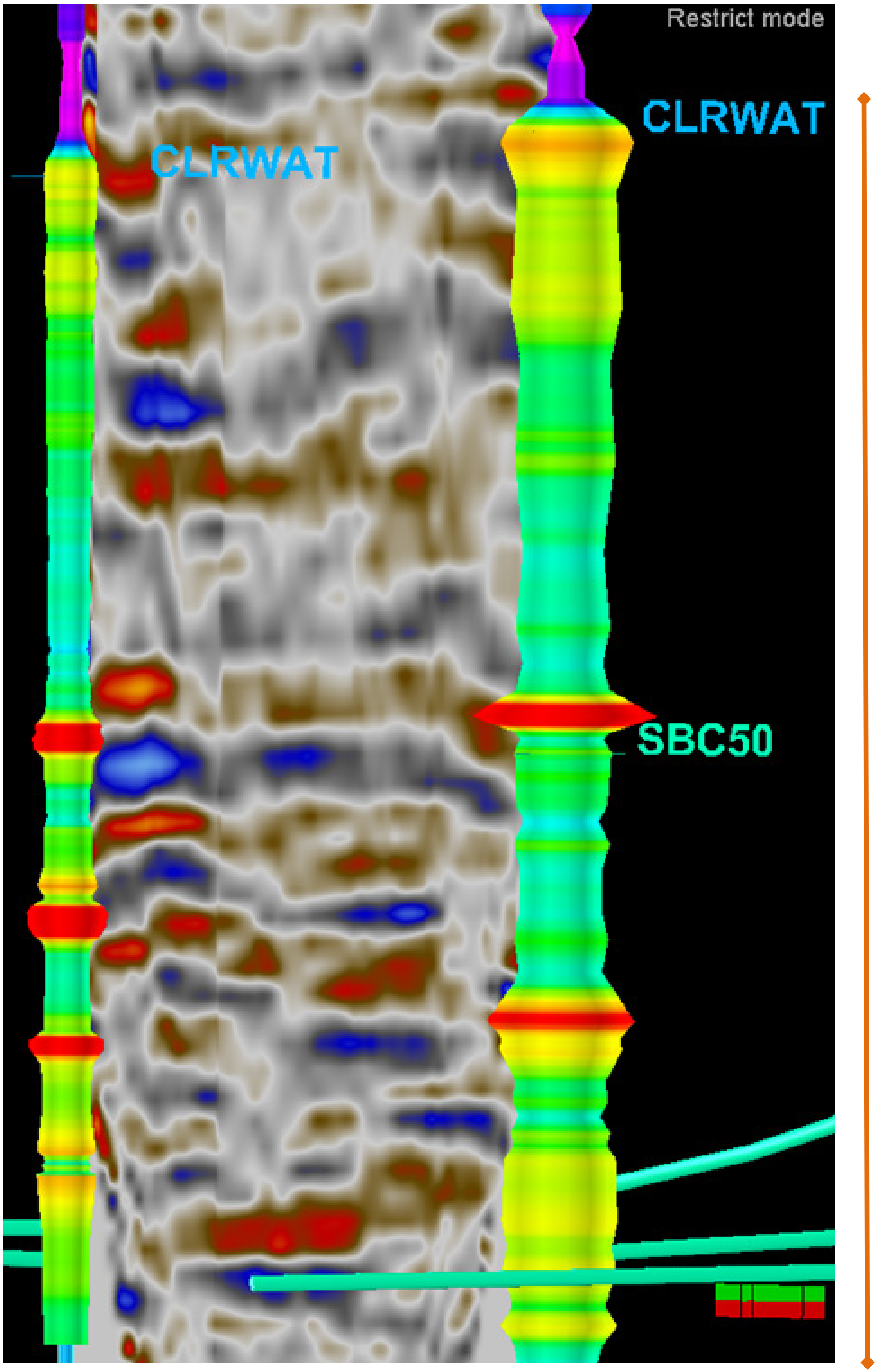


Figure 17: Solvent Detection scenarios for the DTS fiber

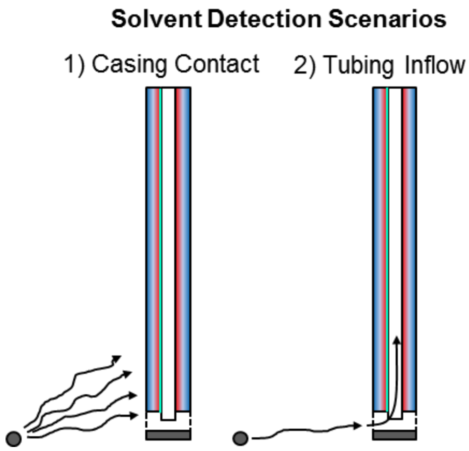


Figure 18: Passive Seismic Event Locations for HW3 Cycle 1

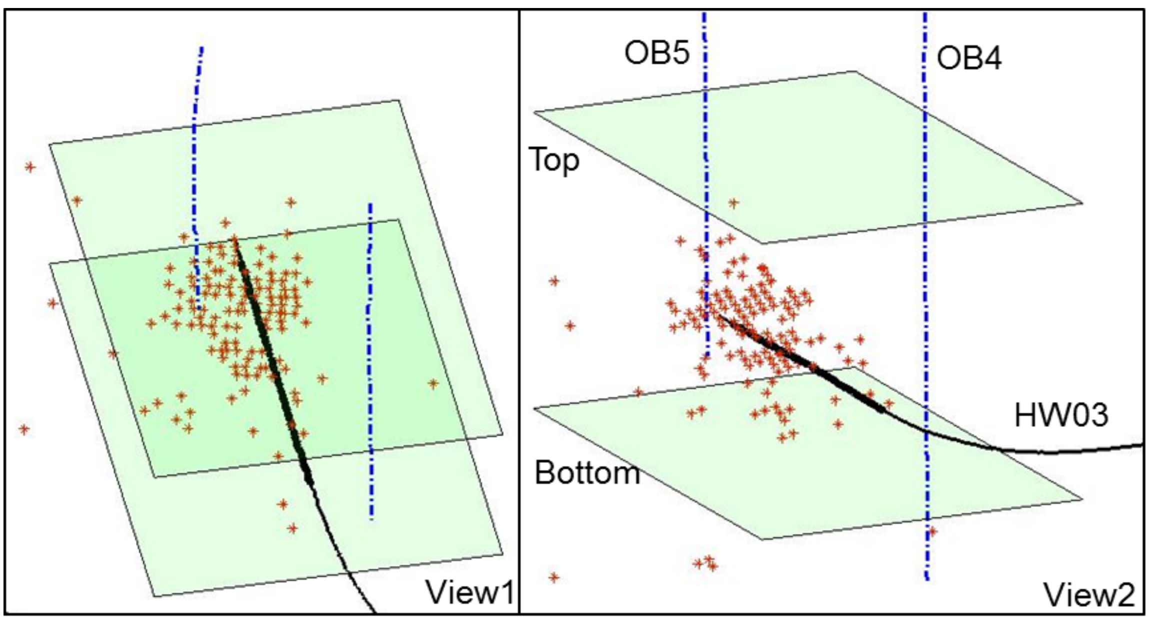


Figure 19: HW2 Cycle 3 Injection Summary with OB3 response

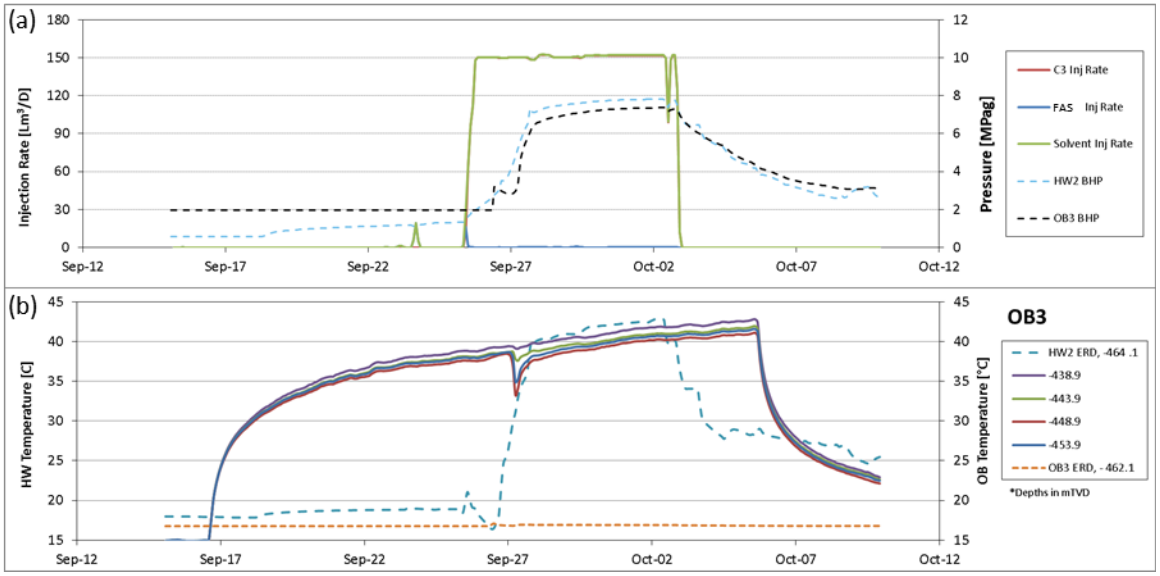


Figure 20: OB3 HW2 Cycle 3 temperature response and tubing inflow interpretation

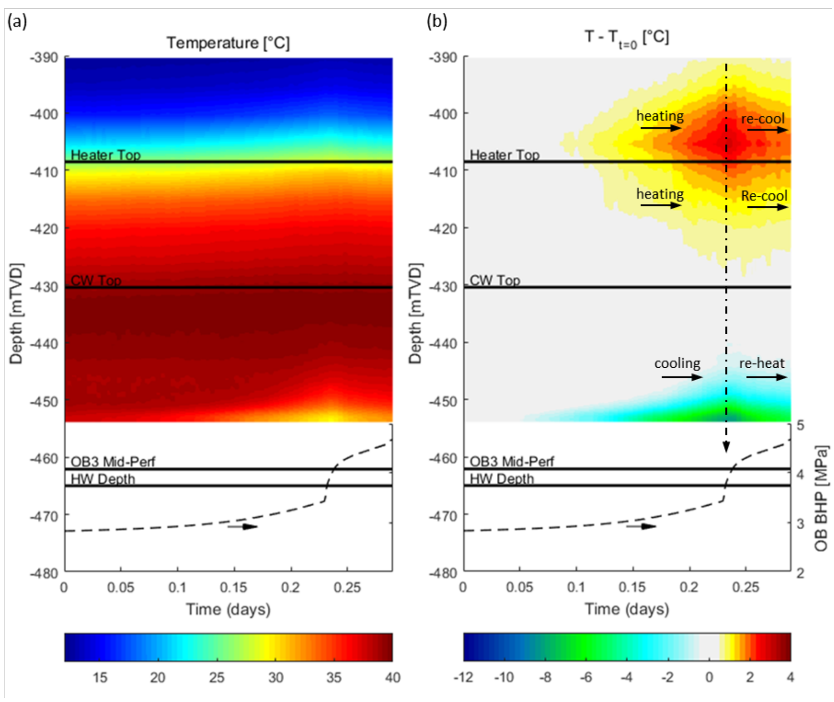


Figure 21: Examples of Wellbore Utilization for HW2

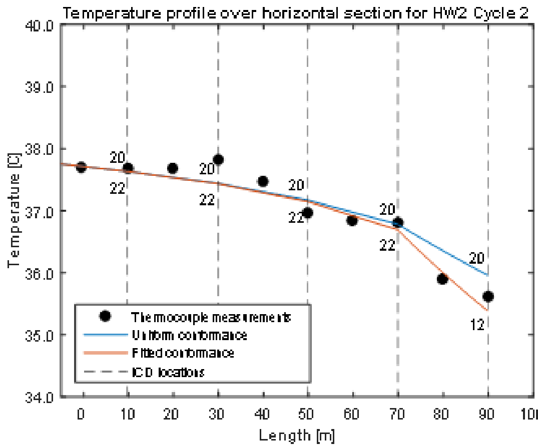


Figure 22: Solvent Chamber Boundary Inferred from the 4D Seismic Results

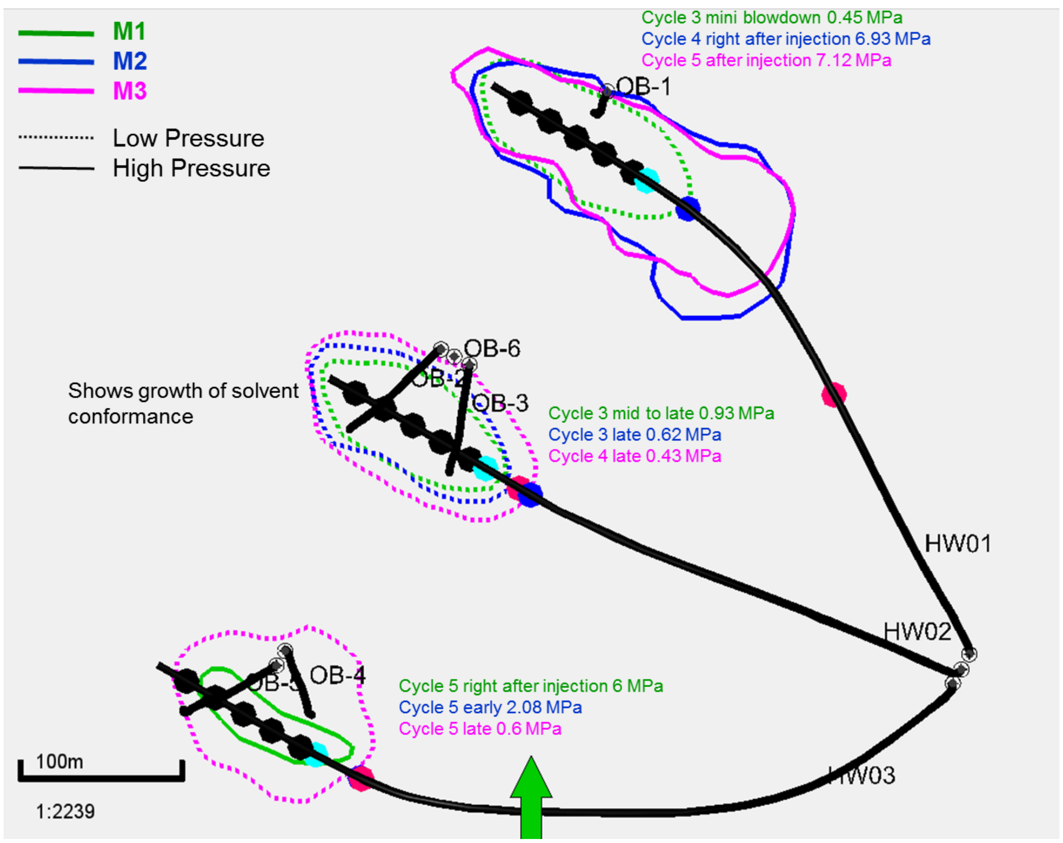


Figure 23: CSP Pilot Site View

Tables

Table 1: Material Balance Data – Injection 2014

Injected Volumes[2] (m³)	HW1 Propane	HW1 FAS[1]	HW2 Propane	HW2 FAS[1]	HW3 Propane	HW3 Diluent	HW3 FAS[1]	TOTAL Propane	TOTAL Diluent	TOTAL FAS[1]
January	-	-	-	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	149.5	4.7	-	149.5	4.7	-
June	-	-	-	-	315.5	52.4	-	315.5	52.4	-
July	-	-	-	-	-	-	-	-	-	-
August	-	-	-	-	-	-	-	-	-	-
September	-	-	-	-	10.6	54.3	-	10.6	54.3	-
October	-	-	-	-	-	-	-	-	-	-
November	-	-	-	-	-	-	-	-	-	-
December	-	-	-	-	-	-	-	-	-	-
Total 2014	**-**	**-**	**-**	**-**	**475.6**	**117.5**	**-**	**475.6**	**117.5**	**-**

[1]Flow assurance solvent (FAS)

[2]Injectant volumes indicate delivered to the reservoir and do not include 315.9 [m³] of diluent / flow assurance solvent used in the surface facilities or the within the wellbore

Table 2: Material Balance Data – Injection 2015

	HW1		HW2		HW3		Total	
Injected Volumes[2] (m^3)	**Propane**	**FAS[1]**	**Propane**	**FAS[1]**	**Propane**	**FAS[1]**	**Propane**	**FAS[1]**
January	-	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-
June	-	-	-	-	526.8	75.1	526.8	75.1
July	-	-	-	-	-	-	-	-
August	-	-	-	-	-	-	-	-
September	-	-	-	-	895.3	118.8	895.3	118.8
October	-	-	-	-	-	-	-	-
November	-	-	-	-	-	-	-	-
December	-	-	-	-	-	-	-	-
Total 2015	**-**	**-**	**-**	**-**	**1422.1**	**193.9**	**1422.1**	**193.9**

[1]Flow assurance solvent (FAS)

[2]Injectant volumes indicate delivered to the reservoir and do not include 545.8 [m^3] of flow assurance solvent used in the surface facilities or the within the wellbore

Table 3: Material Balance Data – Injection 2016

	HW1		HW2		HW3		Total	
Injected Volumes[2] (m^3)	**Propane**	**FAS[1]**	**Propane**	**FAS[1]**	**Propane**	**FAS[1]**	**Propane**	**FAS[1]**
January	-	-	-	-	-	-	0.0	0.0
February	439.5	62.2	-	-	-	-	439.5	62.2
March	-	-	-	-	1178.0	158.5	1178.0	158.5
April	599.9	78.1			406.9	55.9	1006.8	134.0
May	-	-	507.2	8.0	-	-	507.2	8.0
June	-	-	-	-	-	-	0.0	0.0
July	1109.2	152.7	598.6	6.9	-	-	1707.8	159.3
August	-	-	-	-	-	-	0.0	0.0
September	-	-	827.4	8.7	-	-	827.4	8.7
October	-	-	272.4	-	-	-	272.4	0.0
November	-	-	-	-	356.8	90.9	356.8	90.9
December	-	-	-	-	2401.9	90.9	2401.9	90.9
Total 2016	**2148.6**	**293.0**	**2205.6**	**23.6**	**4343.5**	**396.2**	**8697.8**	**712.8**

[1]Flow assurance solvent (FAS)

[2]Injectant volumes indicate delivered to the reservoir and do not include 446.6 [m^3] of flow assurance solvent used in the surface facilities or the within the wellbore

Table 4: Material Balance Data – Injection 2017

	HW1		HW2		HW3		Total	
Injected Volumes[2] (m^3)	**Propane**	**FAS[1]**	**Propane**	**FAS[1]**	**Propane**	**FAS[1]**	**Propane**	**FAS[1]**
January	1158.2	25.6	-	-	-	-	1158.2	25.6
February	1016.1	0.0	-	-	-	-	1016.1	0.0
March	-	-	1587.1	37.6	-	-	1587.1	37.6
April	-	-	375.8	5.1	-	-	375.8	5.1
May	-	-	-	-	-	-	-	-
June	-	-	-	-	-	-	-	-
July	-	-	-	-	-	-	-	-
August	-	-	-	-	-	-	-	-
September	-	-	-	-	-	-	-	-
October	-	-	-	-	-	-	-	-
November	1657.0	27.1	-	-	-	-	1657.0	27.1
December	1521.0	0.0	-	-	-	-	1521.0	0.0
Total 2017	**5352.3**	**52.7**	**1962.9**	**42.7**	**-**	**-**	**7315.2**	**95.4**

[1]Flow assurance solvent (FAS)

[2]Injectant volumes indicate delivered to the reservoir and do not include 283.1 [m^3] of flow assurance solvent used in the surface facilities or the within the wellbore

Table 5: Material Balance Data – Injection 2018

	HW1		HW2		HW3		Total	
Injected Volumes[2] (m³)	**Propane**	**FAS[1]**	**Propane**	**FAS[1]**	**Propane**	**FAS[1]**	**Propane**	**FAS[1]**
January	-	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-
March	-	-	3188.1	30.9	1291.6	6.9	4479.7	37.8
April	-	-	-	-	3525.7	0.0	3525.7	0.0
May	-	-	-	-	-	-	-	-
June	-	-	-	-	-	-	-	-
July	-	-	-	-	-	-	-	-
August	-	-	-	-	-	-	-	-
September	-	-	-	-	-	-	-	-
October	-	-	-	-	-	-	-	-
November	-	-	-	-	-	-	-	-
December	-	-	-	-	-	-	-	-
Total 2018	**-**	**-**	**3188.1**	**30.9**	**4817.3**	**6.9**	**8005.4**	**37.8**

[1]Flow assurance solvent (FAS)

[2]Injectant volumes indicate delivered to the reservoir and do not include 493.3 [m³] of flow assurance solvent used in the surface facilities or the within the wellbore

Table 6: Material Balance Data – Injection Total

	HW1		HW2		HW3			TOTAL		
Injected Volumes[2] (m^3)	Propane	FAS[1]	Propane	FAS[1]	Propane	Diluent	FAS[1]	Propane	Diluent	FAS[1]
2014	-	-	-	-	475.6	117.5	-	475.6	117.5	-
2015	-	-	-	-	1422.1	-	193.9	1422.1	-	193.9
2016	2148.6	293.0	2205.6	23.6	4343.6	-	396.2	8697.8	-	712.8
2017	5352.3	52.7	1962.9	42.7	-	-	-	7315.2	-	95.4
2018	-	-	3188.1	30.9	4817.3	-	6.9	8005.4	-	37.8
Total	**7500.9**	**345.7**	**7356.6**	**97.2**	**11058.6**	**117.5**	**597.0**	**25916.1**	**117.5**	**1040.0**

[1]Flow assurance solvent (FAS)

[2]Injectant volumes indicate delivered to the reservoir and do not include 2084.5 [m^3] of diluent / flow assurance solvent used in the surface facilities or the within the wellbore

Table 7: Material Balance Data – Total Production 2014

Produced Volumes[1] (m^3)	Bitumen	Water	Sol'n Gas	Propane	Diluent	Flow Assurance Solvent
January	0.0	0.0	0.0	0.0	0.0	0.0
February	0.0	0.0	0.0	0.0	0.0	0.0
March	0.0	0.0	0.0	0.0	0.0	0.0
April	0.0	0.0	0.0	0.0	0.0	0.0
May	0.0	0.0	0.0	0.0	0.0	0.0
June	5.7	0.0	23.5	23.8	3.6	0.0
July	0.0	0.0	0.0	0.0	0.0	0.0
August	16.5	1.5	118.3	28.6	12.9	0.0
September	5.7	0.0	68.3	8.1	31.0	0.0
October	0.0	0.0	0.0	0.0	0.0	0.0
November	0.0	0.0	0.0	0.0	0.0	0.0
December	0.0	0.0	0.0	0.0	0.0	0.0
Total 2014	**27.9**	**1.5**	**210.1**	**60.4**	**47.4**	**0.0**

[1]Produced volumes indicate recovered from the reservoir and do not include 315.9 [m^3] of diluent and flow assurance solvent used for the surface facilities or the within the wellbore

Table 8: Material Balance Data – Total Production 2015

Produced Volumes[1] (m^3)	Bitumen	Water	Sol'n Gas	Propane	Diluent	Flow Assurance Solvent
January	0.0	0.0	0.0	0.0	0.0	0.0
February	0.0	0.0	0.0	0.0	0.0	0.0
March	0.0	0.0	0.0	0.0	0.0	0.0
April	52.3	12.5	212.1	32.2	23.6	0.0
May	77.5	75.4	382.4	37.8	18.8	0.0
June	13.4	24.6	153.6	6.2	2.6	0.0
July	205.3	51.4	1832.1	235.2	10.5	28.2
August	113.1	93.3	780.2	57.9	4.5	5.5
September	16.9	14.9	597.7	112.9	0.4	24.5
October	197.3	68.4	2508.4	292.9	0.0	54.7
November	130.1	80.0	1146.4	77.5	0.0	10.4
December	74.7	78.2	645.3	41.1	0.0	5.5
Total 2015	**880.4**	**498.7**	**8258.2**	**893.7**	**60.4**	**128.8**

[1]Produced volumes indicate recovered from the reservoir and do not include 545.8 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 9: Material Balance Data – Total Production 2016

Produced Volumes[1] (m^3)	Bitumen	Water	Sol'n Gas	Propane	Flow Assurance Solvent
January	0.2	2.0	1.3	0.1	0.0
February	219.0	262.6	2694.9	157.9	20.3
March	133.5	174.8	1748.4	68.6	6.5
April	231.2	21.8	1473.5	711.3	119.5
May	566.5	177.8	5000.3	443.0	57.0
June	333.2	272.5	4582.5	185.6	21.0
July	325.9	187.9	1953.1	570.4	45.9
August	604.4	308.0	5252.2	436.2	65.7
September	278.0	260.6	3611.0	166.1	19.0
October	395.6	377.0	3915.6	567.3	14.1
November	312.6	359.0	3888.3	175.0	10.6
December	249.7	187.8	2606.3	496.2	32.6
Total 2016	**3649.8**	**2591.9**	**36727.5**	**3977.8**	**412.2**

[1]Produced volumes indicate recovered from the reservoir and do not include 446.6 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 10: Material Balance Data – Total Production 2017

Produced Volumes[1] (m^3)	Bitumen	Water	Sol'n Gas	Propane	Flow Assurance Solvent
January	300.0	183.4	2724.3	689.2	62.3
February	262.1	252.4	2363.9	609.9	32.6
March	512.6	252.2	4176.6	528.9	33.7
April	469.3	177.1	3591.5	616.4	16.7
May	604.7	229.8	4625.9	589.7	10.3
June	484.6	268.6	7878.5	305.4	6.7
July	392.7	358.8	9130.5	242.1	5.1
August	324.6	399.2	8585.5	189.5	4.2
September	252.7	410.6	7081.9	145.8	3.3
October	245.5	445.9	7028.7	136.6	2.9
November	203.8	414.9	6788.4	103.3	2.4
December	93.6	251.4	2958.2	350.7	6.4
Total 2017	**4146.2**	**3644.3**	**66933.8**	**4507.4**	**186.7**

[1]Produced volumes indicate recovered from the reservoir and do not include 283.1 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 11: Material Balance Data – Total Production 2018

Produced Volumes[1] (m^3)	Bitumen	Water	Sol'n Gas	Propane	Flow Assurance Solvent
January	149.1	484.2	2235.6	617.5	7.9
February	309.3	553.8	5932.4	379.6	4.7
March	197.6	241.1	4353.6	410.4	1.7
April	121.4	17.2	1017.9	473.7	0.7
May	0.0	0.0	0.0	0.0	0.0
June	72.3	0.0	959.8	704.2	0.0
July	137.8	1.4	219.4	449.5	0.0
August	0.0	0.0	0.0	0.0	0.0
September	19.9	0.0	0.0	72.4	0.0
October	547.9	185.1	2811.9	759.5	0.0
November	610.1	332.6	6250.9	422.1	0.0
December	536.1	301.3	6634.5	338.0	0.0
Total 2018	**2701.5**	**2116.6**	**30415.9**	**4626.9**	**15.1**

[1]Produced volumes indicate recovered from the reservoir and do not include 493.3 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 12: Material Balance Data – Total Production Total

Produced Volumes[1] (m³)	**Bitumen**	**Water**	**Sol'n Gas**	**Propane**	**Diluent**	**Flow Assurance Solvent**
2014	27.9	1.5	210.1	60.4	47.4	0.0
2015	880.4	498.7	8258.2	893.7	60.4	128.8
2016	3649.8	2591.9	36727.5	3977.8	0.0	412.2
2017	4146.2	3644.3	66933.8	4507.4	0.0	186.7
2018	2701.5	2116.6	30415.9	4626.9	0.0	15.1
Total	**11405.8**	**8853.0**	**142545.5**	**14066.3**	**107.8**	**742.8**

[1]Produced volumes indicate recovered from the reservoir and do not include 2084.5 [m³] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 13: Material Balance Data – HW1 Production 2016

Produced Volumes[1] (m^3)	**Bitumen**	**Water**	**Sol'n Gas**	**Propane**	**Flow Assurance Solvent**
January	0.0	0.0	0.0	0.0	0.0
February	102.3	17.2	473.9	96.0	13.1
March	90.2	42.7	1213.8	46.2	4.4
April	119.7	7.4	588.7	197.0	29.2
May	226.3	47.1	3505.4	123.3	19.2
June	93.9	65.8	2255.6	44.2	7.9
July	34.6	12.2	567.4	238.9	37.3
August	331.7	25.0	3599.0	298.6	58.0
September	156.5	51.2	2569.7	105.7	14.5
October	83.7	60.8	876.4	46.1	9.7
November	66.5	74.9	653.8	37.1	7.6
December	89.7	104.4	1067.4	51.1	7.0
Total 2016	**1395.2**	**508.8**	**17371.0**	**1284.2**	**208.0**

[1]Produced volumes indicate recovered from the reservoir and do not include 446.5 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 14: Material Balance Data – HW1 Production 2017

Produced Volumes[1] (m^3)	Bitumen	Water	Sol'n Gas	Propane	Flow Assurance Solvent
January	19.7	41.3	197.2	13.7	1.2
February	10.2	0.0	181.7	407.7	15.2
March	266.0	13.7	1370.9	365.3	19.2
April	241.9	29.6	1677.6	145.5	6.9
May	165.3	51.6	1924.4	98.0	2.2
June	146.9	65.5	3989.0	94.8	0.2
July	128.5	72.4	4114.0	80.9	0.0
August	108.2	66.3	3023.8	59.3	0.0
September	79.8	75.0	2235.4	44.6	0.0
October	77.5	61.3	1303.6	39.3	0.0
November	31.8	39.2	499.5	14.0	0.0
December	0.7	0.0	155.4	304.6	4.8
Total 2017	**1276.3**	**516.0**	**20672.5**	**1667.6**	**49.6**

[1]Produced volumes indicate recovered from the reservoir and do not include 283.0 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 15: Material Balance Data – HW1 Production 2018

Produced Volumes[1] (m^3)	Bitumen	Water	Sol'n Gas	Propane	Flow Assurance Solvent
January	50.1	0.0	757.0	572.5	6.5
February	198.0	39.6	2591.0	320.8	3.6
March	140.4	33.5	2368.4	102.8	1.0
April	82.2	17.2	474.2	59.8	0.7
May	0.0	0.0	0.0	0.0	0.0
June	0.0	0.0	0.0	0.0	0.0
July	0.0	0.0	0.0	0.0	0.0
August	0.0	0.0	0.0	0.0	0.0
September	0.0	0.0	0.0	0.0	0.0
October	80.4	22.1	267.9	50.3	0.0
November	202.0	71.8	1733.6	116.9	0.0
December	169.6	61.9	2250.8	94.5	0.0
Total 2017	**922.8**	**246.0**	**10442.8**	**1317.6**	**11.8**

[1]Produced volumes indicate recovered from the reservoir and do not include 493.3 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 16: Material Balance Data – HW1 Production Total

Produced Volumes[1] (m^3)	Bitumen	Water	Sol'n Gas	Propane	Flow Assurance Solvent
2014	0.0	0.0	0.0	0.0	0.0
2015	0.0	0.0	0.0	0.0	0.0
2016	1395.2	508.8	17371.0	1284.2	208.0
2017	1276.3	516.0	20672.5	1667.6	49.6
2018	922.8	246.0	10442.8	1317.6	11.8
Total	**3594.3**	**1270.8**	**48486.3**	**4269.4**	**269.4**

[1]Produced volumes indicate recovered from the reservoir and do not include 2084.5 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 17: Material Balance Data – HW2 Production 2016

Produced Volumes[1] (m³)	**Bitumen**	**Water**	**Sol'n Gas**	**Propane**	**Flow Assurance Solvent**
January	0.0	0.0	0.0	0.0	0.0
February	0.0	0.0	0.0	0.0	0.0
March	0.0	0.0	0.0	0.0	0.0
April	0.0	0.0	0.0	0.0	0.0
May	117.2	15.7	455.8	105.8	3.7
June	72.6	65.4	1754.3	42.5	0.0
July	168.6	16.1	895.7	265.8	0.0
August	155.9	68.8	1164.9	78.8	0.0
September	53.3	52.0	811.4	26.6	0.0
October	228.2	13.6	1613.4	479.2	0.0
November	173.7	40.4	1593.8	104.2	0.0
December	137.7	83.4	1019.6	69.2	0.0
Total 2016	**1107.2**	**355.4**	**9308.9**	**1172.1**	**3.7**

[1]Produced volumes indicate recovered from the reservoir and do not include 446.6 [m³] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 18: Material Balance Data – HW2 Production 2017

Produced Volumes[1] (m³)	Bitumen	Water	Sol'n Gas	Propane	Flow Assurance Solvent
January	108.8	137.0	1279.1	53.5	0.0
February	69.6	190.5	1102.9	31.9	0.0
March	27.7	115.3	653.3	15.5	0.0
April	50.0	2.6	518.4	371.6	0.0
May	276.5	31.8	1489.4	408.6	0.0
June	199.4	51.2	2023.8	139.0	0.0
July	161.2	105.9	3155.3	102.7	0.0
August	119.4	130.5	2740.5	74.9	0.0
September	91.9	129.5	2088.8	54.3	0.0
October	91.6	153.1	2434.8	50.9	0.0
November	79.7	141.3	1925.2	40.8	0.0
December	36.3	99.9	554.2	16.8	0.0
Total 2017	**1312.2**	**1288.6**	**19965.8**	**1360.6**	**0.0**

[1]Produced volumes indicate recovered from the reservoir and do not include 283.1 [m³] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 19: Material Balance Data – HW2 Production 2018

Produced Volumes[1] (m^3)	**Bitumen**	**Water**	**Sol'n Gas**	**Propane**	**Flow Assurance Solvent**
January	54.9	265.8	569.1	25.5	0.0
February	68.0	206.2	1215.9	33.5	0.0
March	29.0	7.8	433.7	290.3	0.0
April	39.2	0.0	543.7	413.9	0.0
May	0.0	0.0	0.0	0.0	0.0
June	0.0	0.0	0.0	0.0	0.0
July	0.0	0.0	0.0	0.0	0.0
August	0.0	0.0	0.0	0.0	0.0
September	19.9	0.0	0.0	72.4	0.0
October	247.7	36.3	1300.7	444.5	0.0
November	219.1	111.1	2349.2	157.8	0.0
December	181.3	92.0	2194.7	117.5	0.0
Total 2018	**859.1**	**719.1**	**8607.2**	**1555.3**	**0.0**

[1]Produced volumes indicate recovered from the reservoir and do not include 493.3 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 20: Material Balance Data – HW2 Production Total

Produced Volumes[1] (m³)	Bitumen	Water	Sol'n Gas	Propane	Flow Assurance Solvent
2014	0.0	0.0	0.0	0.0	0.0
2015	0.0	0.0	0.0	0.0	0.0
2016	1107.2	355.4	9308.9	1172.1	3.7
2017	1312.2	1288.6	19965.8	1360.6	0.0
2018	859.1	719.1	8607.2	1555.3	0.0
Total	**3278.5**	**2363.1**	**37881.8**	**4088.1**	**3.7**

[1]Produced volumes indicate recovered from the reservoir and do not include 2078.6 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 21: Material Balance Data – HW3 Production 2014

Produced Volumes[1] (m^3)	Bitumen	Water	Sol'n Gas	Propane	Diluent	Flow Assurance Solvent
January	0.0	0.0	0.0	0.0	0.0	0.0
February	0.0	0.0	0.0	0.0	0.0	0.0
March	0.0	0.0	0.0	0.0	0.0	0.0
April	0.0	0.0	0.0	0.0	0.0	0.0
May	0.0	0.0	0.0	0.0	0.0	0.0
June	5.7	0.0	23.5	23.8	3.6	0.0
July	0.0	0.0	0.0	0.0	0.0	0.0
August	16.5	1.5	118.3	28.6	12.9	0.0
September	5.7	0.0	68.3	8.1	31.0	0.0
October	0.0	0.0	0.0	0.0	0.0	0.0
November	0.0	0.0	0.0	0.0	0.0	0.0
December	0.0	0.0	0.0	0.0	0.0	0.0
Total 2014	**27.9**	**1.5**	**210.1**	**60.4**	**47.4**	**0.0**

[1]Produced volumes indicate recovered from the reservoir and do not include 315.9 [m^3] of diluent and flow assurance solvent used for the surface facilities or the within the wellbore

Table 22: Material Balance Data – HW3 Production 2015

Produced Volumes[1] (m^3)	Bitumen	Water	Sol'n Gas	Propane	Diluent	Flow Assurance Solvent
January	0.0	0.0	0.0	0.0	0.0	0.0
February	0.0	0.0	0.0	0.0	0.0	0.0
March	0.0	0.0	0.0	0.0	0.0	0.0
April	52.3	12.5	212.1	32.2	23.6	0.0
May	77.5	75.4	382.4	37.8	18.8	0.0
June	13.4	24.6	153.6	6.2	2.6	0.0
July	205.3	51.4	1832.1	235.2	10.5	28.2
August	113.1	93.3	780.2	57.9	4.5	5.5
September	16.9	14.9	597.7	112.9	0.4	24.5
October	197.3	68.4	2508.4	292.9	0.0	54.7
November	130.1	80.0	1146.4	77.5	0.0	10.4
December	74.7	78.2	645.3	41.1	0.0	5.5
Total 2015	**880.4**	**498.7**	**8258.2**	**893.7**	**60.4**	**128.8**

[1]Produced volumes indicate recovered from the reservoir and do not include 545.8 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 23: Material Balance Data – HW3 Production 2016

Produced Volumes[1] (m^3)	Bitumen	Water	Sol'n Gas	Propane	Diluent	Flow Assurance Solvent
January	0.2	2.0	1.3	0.1	0.0	0.0
February	116.7	245.3	2221.0	61.9	0.0	7.2
March	43.3	132.0	534.6	22.4	0.0	2.2
April	111.5	14.4	884.9	514.4	0.0	90.2
May	223.0	115.0	1039.1	213.8	0.0	34.1
June	166.7	141.3	572.5	98.9	0.0	13.1
July	122.7	159.6	490.1	65.8	0.0	8.6
August	116.8	214.2	488.3	58.7	0.0	7.6
September	68.2	157.4	229.9	33.8	0.0	4.5
October	83.8	302.6	1425.8	42.0	0.0	4.4
November	72.4	243.6	1640.7	33.8	0.0	3.0
December	22.3	0.0	519.3	375.9	0.0	25.6
Total 2016	**1147.4**	**1727.6**	**10047.7**	**1521.5**	**0.0**	**200.5**

[1]Produced volumes indicate recovered from the reservoir and do not include 446.6 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 24: Material Balance Data – HW3 Production 2017

Produced Volumes[1] (m^3)	Bitumen	Water	Sol'n Gas	Propane	Diluent	Flow Assurance Solvent
January	171.5	5.0	1248.0	622.0	0.0	61.1
February	182.3	61.9	1079.3	170.3	0.0	17.4
March	219.0	123.2	2152.4	148.1	0.0	14.5
April	177.4	144.9	1395.4	99.4	0.0	9.8
May	162.9	146.4	1212.1	83.1	0.0	8.1
June	138.3	151.8	1865.7	71.5	0.0	6.6
July	103.0	180.6	1861.3	58.5	0.0	5.1
August	97.0	202.4	2821.2	55.3	0.0	4.2
September	81.1	206.0	2757.7	46.9	0.0	3.3
October	76.4	231.5	3290.3	46.4	0.0	2.9
November	92.3	234.4	4363.7	48.5	0.0	2.4
December	56.6	151.6	2248.7	29.3	0.0	1.6
Total 2017	**1557.7**	**1839.8**	**26295.6**	**1479.3**	**0.0**	**137.0**

[1]Produced volumes indicate recovered from the reservoir and do not include 283.1 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 25: Material Balance Data – HW3 Production 2018

Produced Volumes[1] (m^3)	**Bitumen**	**Water**	**Sol'n Gas**	**Propane**	**Diluent**	**Flow Assurance Solvent**
January	44.1	218.5	909.4	19.5	0.0	1.5
February	43.3	308.0	2125.5	25.4	0.0	1.2
March	28.3	199.8	1551.4	17.3	0.0	0.7
April	0.0	0.0	0.0	0.0	0.0	0.0
May	0.0	0.0	0.0	0.0	0.0	0.0
June	72.3	0.0	959.8	704.2	0.0	0.0
July	137.8	1.4	219.4	449.5	0.0	0.0
August	0.0	0.0	0.0	0.0	0.0	0.0
September	0.0	0.0	0.0	0.0	0.0	0.0
October	219.8	126.8	1243.2	264.7	0.0	0.0
November	188.9	149.6	2168.2	147.4	0.0	0.0
December	185.1	147.4	2189.1	126.0	0.0	0.0
Total 2018	**919.7**	**1151.5**	**11365.9**	**1753.9**	**0.0**	**3.3**

[1]Produced volumes indicate recovered from the reservoir and do not include 493.3 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 26: Material Balance Data – HW3 Production Total

Produced Volumes[1] (m³)	Bitumen	Water	Sol'n Gas	Propane	Diluent	Flow Assurance Solvent
2014	27.9	1.5	210.1	60.4	47.4	0.0
2015	880.4	498.7	8258.2	893.7	60.4	128.8
2016	1147.4	1727.6	10047.7	1521.5	0.0	200.5
2017	1557.7	1839.8	26295.6	1479.3	0.0	137.0
2018	919.7	1151.5	11365.9	1753.9	0.0	3.3
Total	**4533.0**	**5219.1**	**56177.4**	**5708.8**	**107.8**	**469.7**

[1]Produced volumes indicate recovered from the reservoir and do not include 2084.5[m³] of diluent and flow assurance solvent used for the surface facilities or the within the wellbore

Table 27: Horizontal Well Completions

Well	Liner	Dual Casing	Instrumentation	Pump
CSP HW-01	Installed	Installed	Installed	Installed
CSP HW-02	Installed	Installed	Installed[1]	Installed
CSP HW-03	Installed	Installed	Installed	Installed

[1]HW-02 well downhole heater not functioning

Table 28: Observation Well Completions

	OB1	OB2	OB3	OB4	OB5	14-18
Tubing OD (mm); Grade	73, J-55	73, J-55	73, J-55	73, J-55	73, J-55	60.3, L-80
Casing OD (mm); Grade	177.8, L-80	177.8, L-80	177.8, L-80	177.8, L-80	177.8, L-80	139.7, J-55
Well PBTD Deepened	N	N	N	N	Y	Y
Wellbore Fluids Upon Completion	Annular Cemented	Annular Cemented	Water Filled	Water Filled	Annular Cemented	Water Filled
Fiber Optics Depth (mKB)	459.9	475.2	462.0	483.0	464.2	484.4
Installation Hardware:	Geophones	Geophones	Heater	Heater	Geophones	Heater
Bottom Geophone or Heater Set Depth (mKB)	459.4	474.4	463.0	484.0	459.2	484.1
Well Perforated	Y	N	Y	N	Y	N
Packer Set Downhole (Y/N)	N	N	Y	N	N	N

Table 29: Observation Well Instrumentation

Well	Completion				Status
	Thermal Fiber Heater	Passive Seismic Geophones	Pressure Measurement	Temperature Measurement	
14-18	✓			✓	Completed
OB-1		✓	✓	✓	Completed
OB-2		✓			Completed
OB-3	✓		✓	✓	Completed
OB-4	✓			✓	Completed
OB-5		✓	✓	✓	Completed

Table 30: Horizontal Well Casing Set Depths

	CSP H-01		CSP H-02		CSP H-03	
	(m MD)	(m TVD)	(m MD)	(m TVD)	(m MD)	(m TVD)
Surface Casing	181	181	183	183	183	183
Intermediate Casing	707	465.4	670	465.2	758	465.3
Total Depth	817.3	465.4	780.5	465.2	867.6	465.3

Table 31: Horizontal Well Cement Bond Log Quality Summary

	CSP H-01	CSP H-02	CSP H-03
Good Quality (%)	94.5	98.1	95.9
Adequate Quality (%)	0.1	0.2	0.2
Low Quality (%)	5.4	1.7	3.9
Probable Cement Top (m KB)	14.3	15.0	17.7

Table 32: Cumulative Production Comparison between Simulation and Pilot

Relative Cumulative Production (% error)[1]	HW1	HW2	HW3	Total
Bitumen	10%	-8%	-1%	0%
Solvent	-7%	3%	0%	-1%
Water	15%	1%	-7%	-2%

[1]Perecent error is defined here as: % error = (Sim cum – Pilot cum)/Pilot cum. Cumulative volumes are for cycles completed by year-end 2018.

Table 33: Average Monthly Pressures 2014

Average Monthly Pressures [kPa]	HW1	OB1	HW2	OB3	HW3	OB5
January	-	-	-	-	-	-
February	-	-	-	-	-	-
March	-	-	-	-	-	-
April	-	-	-	-	3037	3038
May	-	-	-	-	5546	3045
June	-	-	-	-	4557	4153
July	-	-	-	-	3374	3356
August	-	-	-	-	2978	3145
September	-	-	-	-	3220	3189
October	-	-	-	-	3162	3098
November	-	-	-	-	3160	3086
December	-	-	-	-	3135	3066

Table 34: Average Monthly Pressures 2015

Average Monthly Pressures [kPa]	HW1	OB1	HW2	OB3	HW3	OB5
January	-	-	-	-	3149	3062
February	-	-	-	-	3143	3061
March	-	-	-	-	3141	3061
April	-	-	-	-	2253	3012
May	-	-	-	-	1037	2620
June	-	-	-	-	4616	4042
July	-	-	-	-	1504	3004
August	-	-	-	-	975	2644
September	-	-	-	-	4280	4405
October	-	-	-	-	1565	2484
November	-	-	-	-	1305	2179
December	-	-	-	-	1677	2188

Table 35: Average Monthly Pressures 2016

Average Monthly Pressures [kPa]	HW1	OB1	HW2	OB3	HW3	OB5
January	2998	2984	2969	3141	2270	2237
February	4225	5056	2969	3141	1055	2255
March	576	2322	2969	3141	2647	3110
April	3998	5615	2969	3141	3515	3886
May	895	3638	3278	4130	1411	2076
June	458	1402	554	2084	1256	3248
July	4070	5513	2815	3486	1358	2310
August	1027	5931	887	1990	1210	1945
September	624	1868	1862	2729	1282	1953
October	762	1662	2244	2827	1156	1964
November	744	1610	913	1864	1029	2106
December	525	1615	910	1802	5202	5888

Table 36: Average Monthly Pressures 2017

Average Monthly Pressures [kPa]	HW1	OB1	HW2	OB3	HW3	OB5
January	1458	2237	794	1663	1839	2443
February	4964	5016	609	1804	1514	1936
March	1175	1679	2311	2907	1261	2068
April	1056	1580	3723	3701	1356	1830
May	1059	1540	1200	1666	1323	1827
June	828	1475	1124	1622	1256	1819
July	578	1398	860	1571	1248	1810
August	489	1345	722	1475	1140	1797
September	496	1309	692	1481	1091	1780
October	578	1284	567	1407	1003	1764
November	1694	1927	425	1330	760	1744
December	5158	5036	769	1350	1012	1725

Table 37: Average Monthly Pressures 2018

Average Monthly Pressures [kPa]	HW1	OB1	HW2	OB3	HW3	OB5
January	2122	2222	1002	1381	1281	1729
February	973	1456	492	1368	683	1728
March	1040	1420	4531	4224	1461	1960
April	1506	1552	2665	2580	6369	6031
May	2056	1874	3387	3278	4087	4204
June	2303	2133	3222	3130	2756	3086
July	2444	2302	2891	2810	1630	1830
August	2596	2471	2823	2738	2392	2243
September	2664	2560	2751	2693	2694	2602
October	2265	2326	1237	1597	1410	1955
November	1067	1499	1041	1515	1072	1752
December	968	1429	1000	1467	1029	1819

Table 38: Summary of OB well layout and instrumentation

		HW1	HW2			HW3	
		OB1	OB2	OB3	OB6	OB4	OB5
Position to HW		Mid	Toe	Heel	Mid	Heel	Toe
Distance from HW [m]		18	21	13	37	20	16
Instrumentation ID		PSWP	PSW	TFP	TF	TF	PSWP
Solvent detection equipment	ERD	✓		✓			✓
	DTS w. heater			✓	✓	✓	
	PS Geophone	✓	✓				✓
Solvent Arrival Summary							
Cycle 1		**Detected**	**N**	**Detected**	**N**	**N**	**Detected**
Cycle 2		**Detected**	**N**	**Detected**	**N**	**N**	**Detected**
Cycle 3		**Detected**	**N**	**Detected**	**N**	**N**	**Detected**
Cycle 4		**Detected**	**N**	**Detected**	**N**	**N**	**Detected**
Cycle 5		**Detected**	**N**	**Detected**	**N**	**N**	**Detected**
Cycle 6						**N**	**Detected**

Table 39: Summary of Wellbore Utilization

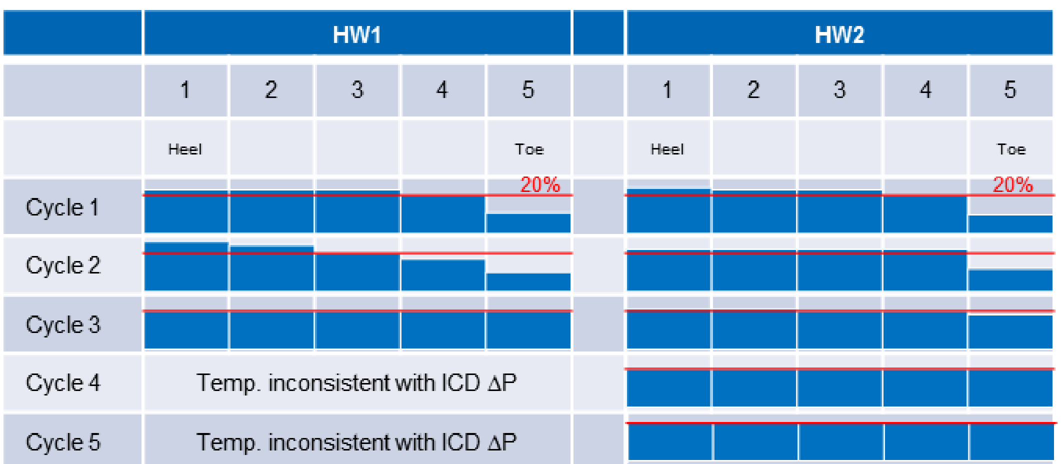


Table 40: Price Assumptions for Revenue Calculations

	2014	2015	2016	2017	2018
Bitumen ($/bbl)[1]	$ 67.20	$ 32.48	$ 26.52	$ 39.13	$ 37.56
Natural Gas ($/mcf)[1]	$ 4.54	$ 2.78	$ 2.41	$ 2.58	$ 2.43
Propane ($/bbl) [2]	$ 53.42	$ 21.21	$ 22.58	$ 49.83	$ 50.47
Flow Assurance Solvent ($/bbl) [2]		$ 105.59	$ 58.14	$ 72.74	$ 58.80
Diluent ($/bbl)[3]	$ 101.08	$ 65.72			

[1]Unit Sales Price (Imperial Annual Form 10-k)

[2]Average price paid for the CSP pilot per year

[3]Based on average Diluent sales price for Imperial CL Royalty Calculation, PST-7a

Table 41: Cumulative Project Revenue

Sales Volumes	2014	2015	2016	2017	2018
Bitumen (m^3)	27.9	880.4	3649.8	4146.2	2701.5
Solution Gas (Sm^3)	210.1	8258.2	36727.5	66933.8	30415.9
Recovered Propane (m^3)	60.4	893.7	3977.8	4507.4	4626.9
Flow Assurance Solvent[1] (m^3)	0.0	674.6	858.7	469.7	508.4
Recovered Diluent[2] (m^3)	363.4	60.4	0.0	0.0	0.0

[1]Includes recovered flow assurance solvent and that used for the surface facilities or the within the wellbore

[2]Includes recovered diluent and that used for the surface facilities or the within the wellbore

Table 42: Cumulative Project Revenue

Cumulative Revenue (k$)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
Bitumen	0	0	0	0	0	12	180	609	1,020	638	2,459
Solution Gas	0	0	0	0	0	0	1	3	6	3	13
Recovered Propane	0	0	0	0	0	20	119	565	1,413	1,469	3,586
Recovered Flow Assurance Solvent	0	0	0	0	0	0	448	314	215	188	1,165
Recovered Diluent	0	0	0	0	0	231	25	0	0	0	256
Total Revenue	**0**	**0**	**0**	**0**	**0**	**263**	**773**	**1,392**	**2,655**	**2,298**	**7,381**

[1] Estimated, see section 8.2 for assumptions

Table 43: Drilling and Facilities Costs

Drilling and Facility Costs (k$)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
Preliminary Engineering	563	802	11	0	0	0	0	0	0	0	1,376
Surface Facilities	0	535	4,659	20,378	20,985	3,279	191	0	0	0	50,027
OB Well Drilling	0	294	4,254	-117	-1	-4	0	0	0	0	4,426
HW Drilling	0	0	67	6,232	2,638	1,316	12	0	0	0	10,265
Completions	0	0	0	1,475	-139	0	0	0	0	0	1,336
Geo Surveillance	0	0	0	5,289	-707	0	-126	-7	0	0	4,449
Total	**563**	**1,631**	**8,991**	**33,257**	**22,776**	**4,591**	**77**	**-7**	**0**	**0**	**71,879**

Table 44: Operating Costs

Operating Costs (k$)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
Total	**0**	**0**	**0**	**0**	**0**	**1,649**	**2,103**	**3,385**	**3,245**	**615**	**10,997**

Table 45: Injectant Costs

Injectant Costs (k$)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
Propane	0	0	0	0	0	343	241	1,500	2,426	2,836	7,347
Flow assurance solvent	0	0	0	0	0	0	605	527	180	275	1,587
Diluent	0	0	0	0	0	433	0	0	0	0	433
Total	**0**	**0**	**0**	**0**	**0**	**776**	**846**	**2,027**	**2,606**	**3,112**	**9,367**

Table 46: Cumulative Project Costs

Cumulative Costs (k$)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
Drilling & Facilities Costs	563	1,631	8,991	33,257	22,776	4,591	77	-7	0	0	71,879
Operating Costs	0	0	0	0	0	1,649	2,103	3,385	3,245	615	10,997
Injectant Costs	0	0	0	0	0	776	846	2,027	2,606	3,112	9,367
Total	**563**	**1,631**	**8,991**	**33,257**	**22,776**	**7,016**	**3,026**	**5,405**	**5,851**	**3,727**	**92,243**

Table 47: Estimated Crown Royalty Calculation

Estimated Royalties (k$)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
Pilot Revenue[1]	0	0	0	0	0	263	773	1392	2655	2298	7,381
Pilot Costs[2]	563	1631	8991	33257	22776	7016	3026	5405	5851	3727	92,243
CCEMC Credit[3]				2,400	2,480	480	960	1,680	0	2,000[5]	10,000
Before Royalty Cash Flow	-563	-1,631	-8,991	-30,857	-20,296	-6,273	-1,293	-2,333	-3,196	571	-74,862
Cold Lake Royalty Rate[4]	27.8%	30.9%	33.8%	34.2%	35.4%	36.8%	27.2%	25.2%	27.4%	31.9%	
Cold Lake Royalty Impact	-156	-504	-3039	-10553	-7185	-2308	-352	-587	-876	182	-25,379
Total Cold Lake Royalties[4]	4,382,405	6,286,055	9,356,655	6,789,645	599,433	772,086	228,198	247,787	440,408	359,903	

[1] Estimated, see Section 8.2 for assumptions

[2] Based on IETP claim form submissions, see Sections 8.3, 8.4 and 8.5

[3] Grant received from Climate Change and Emissions Management Corporation (CCEMC), now ERA, offsetting pilot costs. Credit is shown in year earned, independent of when it was received.

[4] Total Cold Lake rate and royalties paid, which include CSP Pilot costs and revenue. Values may change from previous submissions due to revisions.

[5]Holdback payment received in February 2019

[6]Amendments to prior years were processed therefore the royalties for these years have been revised

Table 48: Major Equipment and Design Basis

	Tag number	Equipment Description	Quantity	Size
1	V-0061/62	Propane vessel	2	4420 mm ID X 24282 mm S/S (working capacity 250 m^3 each)
2	T-0071/72	Diluent tank	2	4648 mm OD X 7315 mm H (750 BBL)
3	P-0071/72	Diluent transfer pumps	2 (2 x 100%)	67 m^3/day each
4	P-0061/62	Propane transfer pumps	2 (2x100%)	175 m^3/day each
5	P-0051/52	Injection pumps	2 (2x100%)	7.5 m^3/hr
6	H-0051/52	Electric solvent heater	2 (2x50%)	200 KW each
7	FIL-0071	Diluent filter	1	100 Microns
8	FIL-0051/52	Solvent filter	2	5 Microns
9	P-0030/40	Multiphase vent gas pumps	2 (2x100%)	153 m^3/h
10	V-0003	Liquid separator	1	736 mm ID X 2550 mm S/S
11	E-0005	Recycle liquid cooler	1	203 KW
12	P-0023	Make up water pumps	1 (1x100%)	100 LPH per pump
13	T-0023	Make up water tank	1	1830 mm OD X 3518 mm H (capacity 8 m^3)
14	H-0053	Electric test fluid heater	1	13 KW
15	H-0054	Electric production heater	1	40 KW
16	V-0011	Test separator	1	1219 mm ID X 3600 mm S /S, Boot 508 mm ID X 1200 mm L
17	P-0024	Purge Liquid Pump	1 (1X100%)	0-1000 LPH
18	PK-001	Instrument air package	1	110 sm^3/hr
19	T-0022	Methanol tank	1	2413 mm ID X 3048 mm H (90 BBL)
20	P-0022	Methanol injection pump	1 (1X100%)	5000 LPD
21	P-0073	Utility diluent pump	1 (1X100%)	8000 LPD
22	T-0001	Pop tank	1	2896 mm ID X 3658 mm High (150 BBL)
23	T-0002/0003	Closed Drain Tank	2	1256 mm OD X 3517 mm OAL
24	K50-1/ K50-2/ K50-3	Pump Jack	3	22.2 KW
25	PK-0031	Portable Compressor	1	1007-3029 Sm^3/D

Appendix A: Process Flow Diagrams (PFDs)

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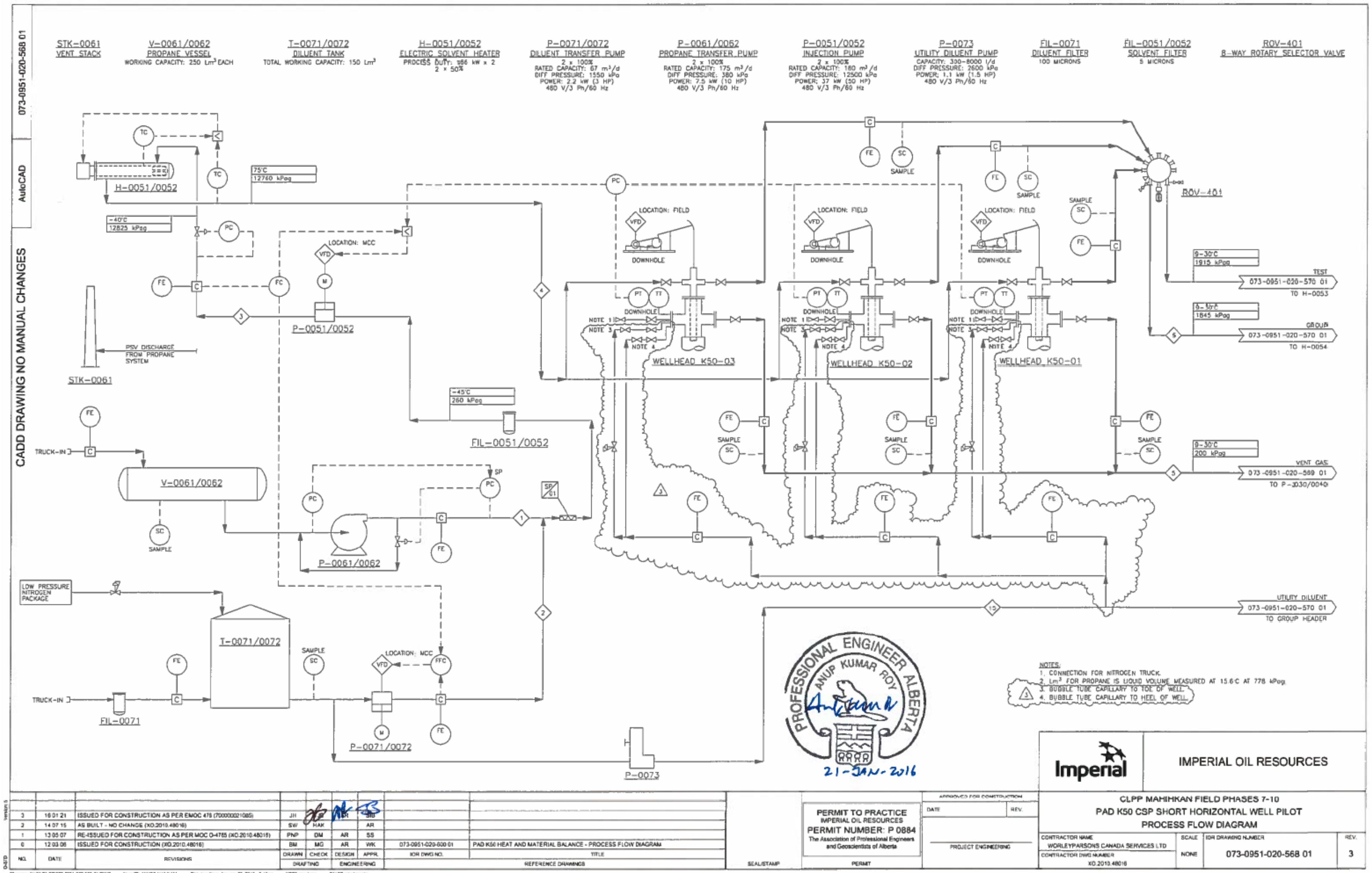
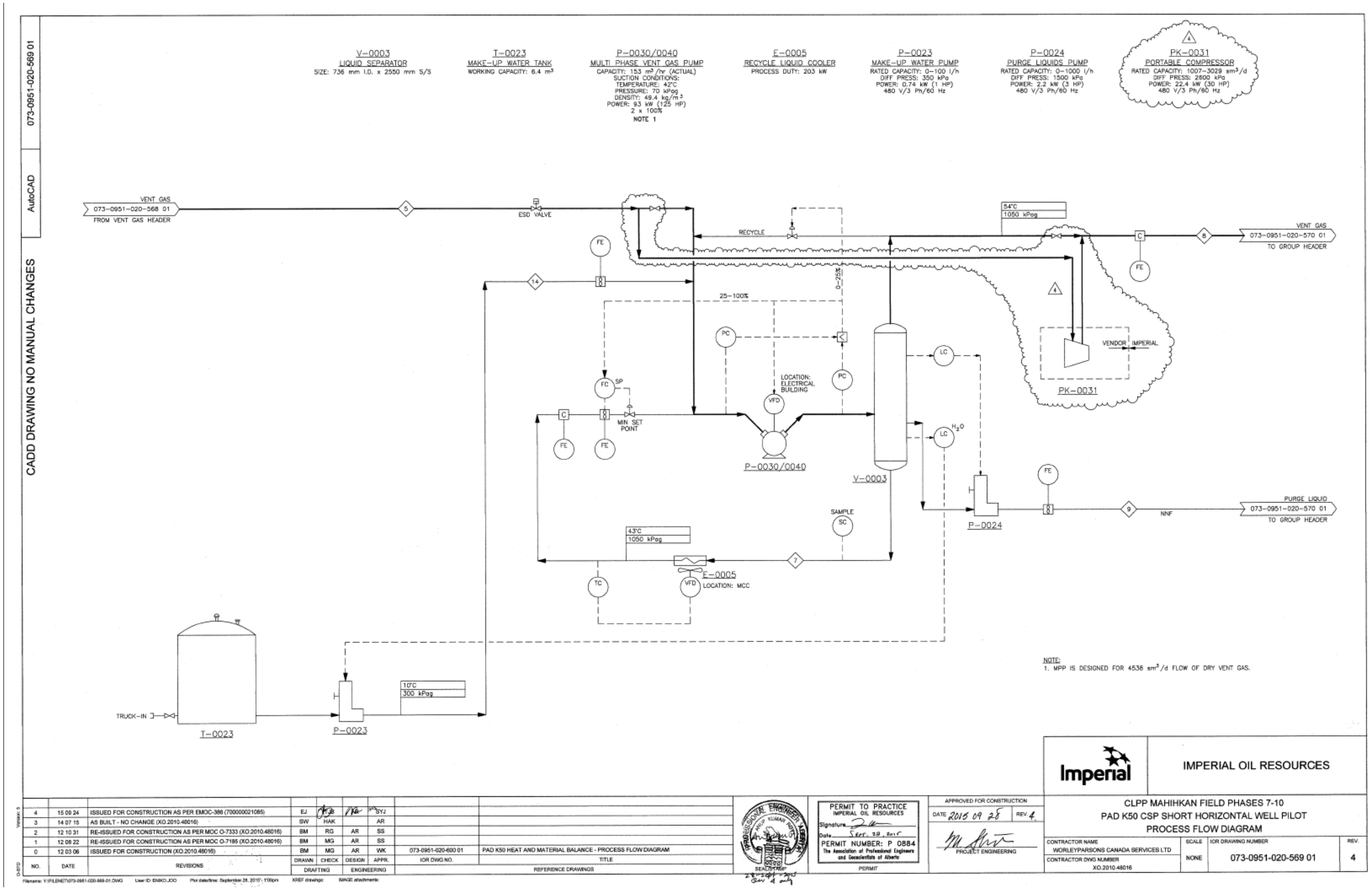
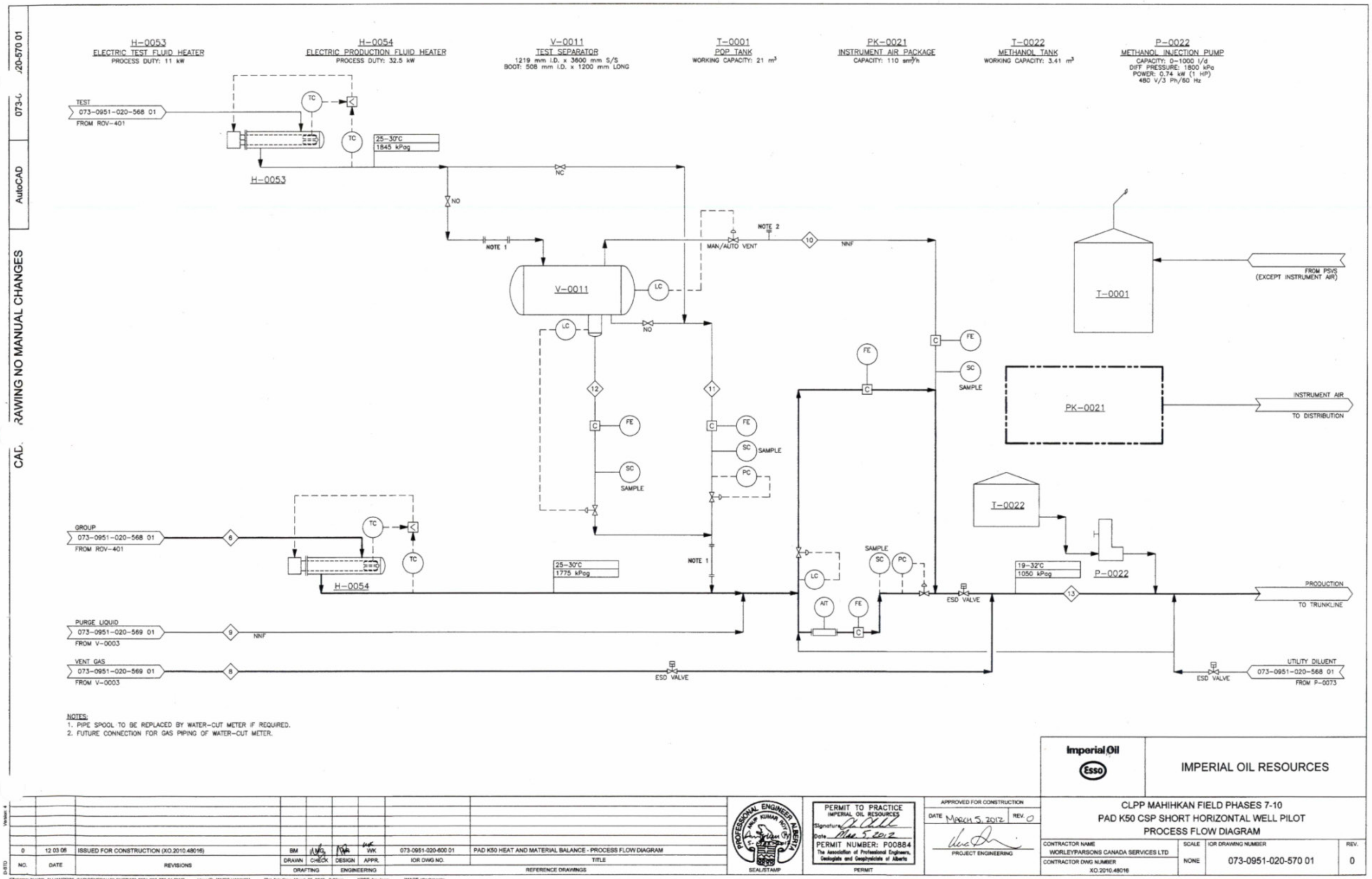


121


V-0003
LIQUID SEPARATOR
SIZE: 736 mm I.D. x 2550 mm S/S
T-0023
MAKE-UP WATER TANK
WORKING CAPACITY: 6.4 m³
P-0030/0040
MULTI PHASE VENT GAS PUMP
E-0005
RECYCLE LIQUID COOLER
PROCESS DUTY: 203 kW
P-0023
MAKE-UP WATER PUMP
P-0024
PURGE LIQUIDS PUMP
PK-0031
PORTABLE COMPRESSOR
VENT GAS
073-0951-020-568 01
FROM VENT GAS HEADER
ESD VALVE
RECYCLE
VENT GAS
073-0951-020-570 01
TO GROUP HEADER
PURGE LIQUID
073-0951-020-570 01
TO GROUP HEADER
TRUCK-IN
NOTE:
1. MPP IS DESIGNED FOR 4538 sm³/d FLOW OF DRY VENT GAS.
CADD DRAWING NO MANUAL CHANGES
AutoCAD
073-0951-020-569 01
Imperial
IMPERIAL OIL RESOURCES
CLPP MAHIHKAN FIELD PHASES 7-10
PAD K50 CSP SHORT HORIZONTAL WELL PILOT
PROCESS FLOW DIAGRAM
WORLEYPARSONS CANADA SERVICES LTD
XO.2010.48016
PERMIT TO PRACTICE
IMPERIAL OIL RESOURCES
PERMIT NUMBER: P 0884
APPROVED FOR CONSTRUCTION
ISSUED FOR CONSTRUCTION AS PER EMOC-386 (700000021085)
AS BUILT - NO CHANGE (XO.2010.48016)
RE-ISSUED FOR CONSTRUCTION AS PER MOC O-7333 (XO.2010.48016)
RE-ISSUED FOR CONSTRUCTION AS PER MOC O-7185 (XO.2010.48016)
ISSUED FOR CONSTRUCTION (XO.2010.48016)
PAD K50 HEAT AND MATERIAL BALANCE - PROCESS FLOW DIAGRAM


H-0053
ELECTRIC TEST FLUID HEATER
PROCESS DUTY: 11 kW
H-0054
ELECTRIC PRODUCTION FLUID HEATER
PROCESS DUTY: 32.5 kW
V-0011
TEST SEPARATOR
1219 mm I.D. x 3600 mm S/S
BOOT: 508 mm I.D. x 1200 mm LONG
T-0001
POP TANK
WORKING CAPACITY: 21 m³
PK-0021
INSTRUMENT AIR PACKAGE
CAPACITY: 110 sm³/h
T-0022
METHANOL TANK
WORKING CAPACITY: 3.41 m³
P-0022
METHANOL INJECTION PUMP
CAPACITY: 0-1000 l/d
DIFF PRESSURE: 1800 kPa
POWER: 0.74 kW (1 HP)
460 V/3 Ph/60 Hz
TEST
073-0951-020-568 01
FROM ROV-401
25-30°C
1845 kPag
GROUP
073-0951-020-568 01
FROM ROV-401
25-30°C
1775 kPag
PURGE LIQUID
073-0951-020-569 01
FROM V-0003
VENT GAS
073-0951-020-569 01
FROM V-0003
FROM PSVS
(EXCEPT INSTRUMENT AIR)
INSTRUMENT AIR
TO DISTRIBUTION
19-32°C
1050 kPag
PRODUCTION
TO TRUNKLINE
UTILITY DILUENT
073-0951-020-568 01
FROM P-0073
MAN/AUTO VENT
ESD VALVE
SAMPLE
NOTE 1
NOTE 2
NNF
NOTES:
1. PIPE SPOOL TO BE REPLACED BY WATER-CUT METER IF REQUIRED.
2. FUTURE CONNECTION FOR GAS PIPING OF WATER-CUT METER.
CAD DRAWING NO MANUAL CHANGES
AutoCAD
0
12 03 06
ISSUED FOR CONSTRUCTION (XO.2010.48016)
073-0951-020-600 01
PAD K50 HEAT AND MATERIAL BALANCE - PROCESS FLOW DIAGRAM
NO.
DATE
REVISIONS
DRAWN
CHECK
DESIGN
APPR.
DRAFTING
ENGINEERING
IOR DWG NO.
TITLE
REFERENCE DRAWINGS
SEAL/STAMP
PERMIT TO PRACTICE
IMPERIAL OIL RESOURCES
PERMIT NUMBER: P00884
The Association of Professional Engineers, Geologists and Geophysicists of Alberta
PERMIT
APPROVED FOR CONSTRUCTION
DATE
REV.
PROJECT ENGINEERING
Imperial Oil
Esso
IMPERIAL OIL RESOURCES
CLPP MAHIHKAN FIELD PHASES 7-10
PAD K50 CSP SHORT HORIZONTAL WELL PILOT
PROCESS FLOW DIAGRAM
CONTRACTOR NAME
WORLEYPARSONS CANADA SERVICES LTD
CONTRACTOR DWG NUMBER
XO.2010.48016
SCALE
NONE
IOR DRAWING NUMBER
073-0951-020-570 01
REV.
0