IETP Application No. 06-094

Imperial Oil Resources – Cyclic Solvent Process Pilot

2017 Annual 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 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 wells drilled for that purpose. The liquid-phase solvent is injected into a horizontal well cyclically and, because of the large mobility contrast between the solvent and the bitumen, it fingers into the bitumen. Following injection, the solvent-bitumen blend is produced from the same well. Cyclic injection and production operations continue for multiple cycles over several years until the bitumen produced no longer justifies the cost of the solvent or until the bitumen production rate is no longer economic. The cyclic operation is followed by a final blow-down period, when additional solvent is recovered by vaporization at low pressure.

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) 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 horizontal wells are operated using CSP as a recovery process. This report summarizes progress that was made through year-end 2017.

The project continued multi-well operation in 2017. At year-end, HW1 had started early-stage production of cycle 5, HW2 was in the late-stage of cycle 4 production and HW3, the initial well, was in late-stage cycle 5 production. The work has continued to focus on active surveillance of the pilot in an effort to achieve high quality data. Operationally, the pilot has moved to limit the use of flow assurance solvent, with HW1 transition to propane only injection for cycles 4 and 5. In general, the well performance is similar and also aligned with the expectations. HW3 has continued to show higher water production and greater sub-surface pressure support than the other wells. Active surveillance and maintaining operational stability remain top priorities for 2018.

2 Summary and Project Status Report

2.1 Members of the Project Team

The following were key members of the CSP pilot team at the end of 2017.

C. (Cheryl) Trudell, PhD, P.Eng.	Research Manager
J. (Jianlin) Wang, PhD	CSP Team Lead
G. (Gordon) MacIsaac, PhD	CSP Reservoir Engineer
M. (Mat) Suitor, P.Eng.	CSP Reservoir Engineer

2.2 Key Activities

Key activities during the reporting period are described below:

HW1

- 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

HW2

- HW2 cycle 3 production continued to March 17
- HW2 cycle 4 injection from March 21 to April 3
- HW2 cycle 4 production from Aril 5 and continued through year-end 2017
- HW2 pump replacement on April 19

HW3

- HW3 cycle 5 continued through year-end 2017

4D seismic

- Monitor 2 shoot on February 8
- Monitor 3 shoot on December 10

2.3 Production, Material and Energy Balance

During 2017 HW1 and HW2 completed cycle 3 and also began cycle 4. By year-end HW1 had completed cycle 4 production, completed cycle 5 injection and had started production of cycle 5. HW2 and HW3 were continuing production of cycle 4 and 5 through year-end, 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 all exist in the liquid phase; the process for determining component volumes is much more challenging than for traditional steam based processes. The injection volumes for each well are shown in Table 1. Total production volumes are given in Table 2 and volumes per well are given in Tables 3 through 5.

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 current reservoir simulation estimate of recovery is 12 [km^3] after the planned five cycles of the pilot with 23 [km^3] solvent injection. The ratio of these values is not indicative of the recovery factor of the process – the wells have been spaced farther apart than would be anticipated during a commercial project, and the process may not run to an economic limit. Recovery factor and reserves will be determined by history-matched reservoir simulation model at the completion of the pilot.

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 1. The six OB wells are drilled from three pads and the three horizontal wells are drilled from a fourth pad. Surface facility and pad locations are shown in Figure 2.

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 Geology

The pilot is being conducted in the Clearwater formation. A cross-section of the reservoir, through the observation wells, is shown in Figure 3. The reservoir consists of two sequences: the lower sequence, between the lower sequence boundary (bright green line in three wells in Figure 3) and the upper sequence boundary (purple line in Figure 3); and, the upper sequence between the upper sequence boundary and the top of the Clearwater formation (red line in Figure 3). 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 3.

The sands are generally clean, although one noticeable feature on the logs is the calcite cemented zones (colored blue in Figure 3). 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 3 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.

4 Well Information

4.1 Drilling, completion, and work-over operations

The 2012 annual report provided a detailed summary of the drilling activities and a brief description of the OB well completions. Figure 4 shows the OB wells surface and bottom-hole locations relative to the horizontal wells (HW1 through HW3) and provides an overview of the OB wells instrumentation for surveillance. The 2013 annual report discussed the work for the first phase of horizontal well completion work. The 2014 annual report discussed the work for the second phase of horizontal well completion work. The OB well completions are summarized in Table 7 and HW completions are summarized in Table 8.

4.2 Wellbore schematics

A general schematic of the three horizontal wells, to be completed similarly, is shown in Figure 5. Schematics of the six observation wells were provided in the 2012 annual report.

4.3 Spacing and pattern

The horizontal wells are spaced approximately 200 [m] apart, with approximately 100 [m] of drainage length per well, as shown in Figures 1 to 4. Adding 50 [m] to the potential drainage area on each end of each HW, the pilot encompasses 120,000 [m^2] (600 [m] x 200 [m]), which is roughly 32.5 acres per well.

4.4 Well operation

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).

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

5 Surface Facilities

5.1 Detailed Design

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, 2017.

5.2 Progress

During the current reporting period there were no significant facility modifications.

5.3 Surface equipment

Table 9 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 Attachment A.

Solvent Preparation & Blending (Injection)

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.

Production System

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. As described in Section 5.2, 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.

5.4 Capacity limitation, operational issues, and equipment integrity

Operational issues encountered during 2017 are grouped as either injection or production system related.

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.

6 Production Performance

6.1 Injection and Production History

The total injection volumes for the pilot and the individual volumes for each well are shown in Table 1. Total production volumes are given in Table 2 and volumes per well are given in Tables 3 through 5.

Table 6 shows the updated production volumes from 2016. The updated volumes reflect changes arising from the sample analysis results and are therefore different than those in the 2016 report. Section 6.2 describes the two-stage process required to estimate the production volumes. The meter readings provide the initial estimates which are later corrected with the sample analysis data.

For each cycle in 2017, the narrative of injection and production events is described in the following sub-sections.

6.1.1 HW1 (Cycle 3 to 5)

Each injection and production narrative for HW1 in 2017 is described below:

HW1 Cycle 3 Production

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.

HW1 Cycle 4 Injection

A pre-injection wellbore treatment was completed using 25.7 [m³] of flow assurance solvent. Injection started on January 24 with a target injection rate of 150 [m³/D] achieved on the first day of injection. The pressure response was gradual and as a result a higher injection rate of 165 [m³/D] was sustained throughout remainder of the injection cycle. A total of 2174 [m³] of propane solvent was injected for the cycle. HW1 Cycle 4 injection was completed on February 7. 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 with peak rates of about 35 [m³/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 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. 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 [m³] of flow assurance solvent. Injection started on December 21 with a target injection rate of 175 [m³/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 [m³/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 [m³] of propane solvent was injected for the cycle. HW1 Cycle 5 injection was completed on completed on December 10. 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

Production began on December 11 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]. Production continued until December 24 at which point heavy liquid build-up in the pipeline led to a shut-in. Production was resumed in early January following a pipeline workover. Heavy liquid build-up in the pipeline resulted from the co-mingling of early production from HW1 and late production from the others wells.

6.1.2 HW2 (Cycle 3 and 4)

Each injection and production narrative for HW2 in 2017 is described below:

HW2 Cycle 3 Production

Production of late-stage cycle 3 continued into March 2017. Leading up to the M2 seismic shoot on February 8, 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.

HW2 Cycle 4 Injection

A pre-injection wellbore treatment was completed using 42.7 [m^3] of flow assurance solvent. Injection started on March 21 with a target injection rate of 150 [m^3/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 [m^3] of propane solvent was injected for the cycle. HW2 Cycle 4 injection was completed on completed on April 3. 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 with below normal rates of about 15 [m^3/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. Thereafter, peak rates production were achieved at about 38 [m^3/D]. The BHP declined naturally and the flowrate followed as expected. Continuous venting began on May 8 and typical mid-stage production was achieved. A low-pressure mini-blow down test was initiated in October and carried through until December 24. 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 due to the heavy liquid build-up in the pipeline. The mini-blow down test was effectively terminated. Cycle 4 production was resumed after the pipeline workover was completed in January of 2018.

6.1.3 HW3 (Cycle 5)

Each injection and production narrative for HW3 in 2017 is described below:

HW3 Cycle 5 Production

Early production of cycle 5 continued from 2016. The cycle progressed normally and lower pressure operation was tested beginning in October. The bottom-hole pressure was lowered from about 1 [MPa] to approximately 600 [kPa], the lowest sustained pressure for this well amongst all of its cycles. The corresponding OB5 pressure was nearly stable at about 1750 [kPa], indicating strong pressure support in the vicinity of this well. Higher venting rates were achieved during the low-pressure operation and higher water-cuts were also observed. Cycle 5 continued production through the year-end.

6.2 Composition of Injected and Produced Fluids

In 2016, HW3 cycle 5 aimed to reduce the amount of flow assurance solvent by lowering the injecting concentration from 12 to 6 vol%. In 2017, the strategy to reduce the flow-assurance solvent as a co-injected solvent continued. HW1 Cycles 4 and 5 removed the use of flow-assurance solvent as a co-injected solvent and HW2 Cycle 4 continued to operate with zero co-injection.

The propane is industrial grade propane with an average of 98 mass% of C3. The composition of the flow assurance solvent is proprietary.

Produced fluids can be comprised of methane, propane, 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, flow assurance solvent and bitumen. The second step happens several months 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 7 shows examples of the characteristic shapes for each liquid phase substance.

By the end of 2017 at total of 11 production cycles had been completed since pilot start up. 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 2016 IETP report. 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.

6.3 Simulation and Prediction of the Pilot Performance

In 2017 the history matching effort continued from work progressed in 2016. Simulation models for each well were history matched for all of the completed cycles, that is: HW1 and HW2 cycles 1 through 3 and HW3 cycles 1 through 4. The simulation model adequately captured the key performance criteria including the compositional data provided by the pilot sampling program. Performance predictions were then generated for the subsequent cycles to test the forecasting capability of the simulation models. Accurate predictions are challenging, but the results to this point are encouraging that the simulation model can be predictive of the CSP process.

7 Pilot Data

7.1 Additional data and Interpretation

CSP surveillance uses an array instrumented OB wells to monitor solvent conformance. In addition, 4D seismic surveys were taken to visualize the solvent conformance at different operating conditions for each of the wells. In the 2016 IETP report the OB well instrumentation was described along with descriptions regarding the extent of the solvent chamber. In 2017, the focus of the subsurface surveillance was the interpretation of the three monitoring seismic surveys, namely M1, M2 and M3. The dates of the surveys are given below:

M1: December 18, 2016
M2: February 8, 2017
M3: December 10, 2017

The timing of the surveys allowed each of the wells to be shot at different operating conditions. The ability to successfully visualize the solvent chamber at both high and low pressure operating conditions was uncertain prior to performing the shoots. For each well images of the solvent chamber were successfully recorded. HW3 showed 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 near 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 had found a path to this region. As mentioned in Section 6.1.1, the rapid pressure decline observed during the production of cycle 4 is consistent with the solvent chamber travelling to a previously unswept region.

8 Pilot Economics

Price data used in this section is a combination of:

- Bitumen/natural gas pricing based on actual prices from Imperial Oil's 2017 10-K filing
- The propane and flow assurance solvent price is estimated based on the average price paid by the CSP pilot in 2017 for each product respectively

The price information can be found in Table 10.

8.1 Sales volumes of natural gas and by-products

In 2017, the pilot produced 66,934 [Sm^3] of natural gas. No natural gas was consumed. Also, the pilot produced 4511 [m^3] of propane and 187 [m^3] of flow assurance solvent from the reservoir. Other than the flow assurance solvent produced from reservoir, the pilot has also recovered all the utility fluid used within the wellbore and surface facilities, totalled 263 [m^3].

8.2 Revenue

As the CSP pilot is part of Imperial Oil's Cold Lake Production Project, injection and production volumes are blended with Mahihkan plant volumes, and thus revenue is not calculated separately. This section provides the methodology of the estimated revenue calculation.

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.

Gross revenue for the pilot in 2017 is estimated to be 2,655 k$. This is based on 4511 [m^3] of propane, 470 [m^3] of flow assurance solvent (including 187 [m^3] recovered from reservoir and 263 [m^3] from surface facilities), 4183 [m^3] of bitumen and 66,934 [Sm^3] of natural gas produced at 39.13 $/bbl, 72.74 $/bbl, 49.83 $/bbl and 2.58 $/mcf, respectively.

A summary of the annual revenues over the project life is given in Table 11.

8.3 Costs

8.4 Drilling, completions, and facilities costs

Table 12 shows that the total drilling, completions, facilities costs incurred in 2017 were 0 k$.

8.5 Direct and indirect operating costs

Table 13 summarizes direct and indirect operating costs incurred in 2017, totalling 3,245 k$.

8.6 Injectant costs

Table 14 summarizes injectant costs by category incurred in 2017, totalling 2,606 k$. Trucking costs associated with transporting each product to site are included.

8.7 Total Costs

A summary of the annual costs incurred over the project life is given in Table 15. Annual credits, such as those received from Emissions Reduction Alberta (formerly known as CCEMC), are deducted from the total costs for cash flow calculations.

8.8 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 16.

8.9 Cash flow

As revenue is only estimated for the pilot, cash flow can only be estimated. Using the data from Tables 11 through 16, it is estimated as follows:

Revenue	= Bitumen + Solution Gas + Propane + Flow Assurance Solvent = 1,020 + 6 + 1,414 + 215 = 2,655 k$
Credits	= ERA Credit = 0 k$
Costs	= Drilling & Facilities Costs + Operating Costs + Injectant Costs - ERA Credit = 0 + 3,245 + 2,606 – 10 = 5,851 k$
Before Royalty Cash Flow	= Revenue – Costs = 2,655 – 5,851 = -3,196 k$
Royalties	= -876 k$
Cash Flow	= Revenue – Costs – Royalties = 2,655 – 5,851 – (-876) = -2320 k$

This estimation of cash flow does not include taxes.

8.10 Deviations from budgeted costs

Changes to individual cost components are expected. To date, there is no change to the total cost of the pilot.

9 Environmental/Regulatory/Compliance

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

9.1 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.

9.2 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.

9.3 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.

9.4 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.

9.5 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.

9.6 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).

9.7 Reclamation

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

10 Future Operating Plan

10.1 Project schedule

The key activities for 2018 are listed below:

- Continue to produce HW1 Cycle 5 through year-end 2018.
- Complete HW2 Cycle 4 and begin cycle 5 in Q2 2018
- Complete HW3 Cycle 5 and begin cycle 6 in Q1 2018
- Initiate a mini-blow down of HW1 in Q4 2018
- Continue with stable multi-well pilot operation. Pilot surveillance and data interpretation, simulation history matching, and operation sensitivity studies are part of the work plan
- Analysis and interpretation of the M3 seismic survey

10.2 Changes in pilot operation

The pilot progress during 2017 has not resulted in significant changes to the pilot operation schedule.

10.3 Optimization strategies

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.

10.4 Salvage update

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

11 Interpretations and Conclusions

11.1 Overall Performance Assessment

To summarize the overall 2017 performance:

- HW1 successfully completed cycle 3, cycle 4, cycle 5 injection and began production of cycle 5
- HW2 successfully competed cycle 3, cycle 4 injection and continued cycle 4 production through year-end
- HW3 continued cycle 5 production through year-end
- The overall performance of the pilot was aligned with expectations
- M2 and M3 seismic surveys completed

11.2 Difficulties Encountered

A difficulty encountered in 2017 occurred near year-end. Heavy liquid build-up in the production pipeline caused a PAD shut-in. At the time, early- and late-stage production flow streams from different wells were co-mingled and sent to the pipeline. Generally, flow assurance solvent can mitigate the build-up. In this particular case, operational challenges including extreme cold weather led to excessive build-up within the line, which subsequently caused a PAD shut-in and work-over.

11.3 Technical and Economic Viability

The current pilot represents one study that will be used in combination with others to evaluate the overall technical viability of the CSP process. Judgements regarding the technical and economic viability of the CSP process have not yet been made by year-end 2017.

11.4 Overall Effect on Gas/Bitumen Recovery

This has yet to be determined.

11.5 Future expansion or commercial field application

Decisions regarding the future expansion of the CSP pilot or commercial field application have not been made by year-end 2017.

Tables

Table 1: Material Balance Data – Injection

	HW1		HW2		HW3		Total	
Injected Volumes[1] (m^3)	**Propane**	**FAS[2]**	**Propane**	**FAS[2]**	**Propane**	**FAS[2]**	**Propane**	**FAS[2]**
January	1158.2	25.6	-	-	-	-	1158	26
February	1016.1	0.0	-	-	-	-	1016	-
March	-	-	1587.1	37.6	-	-	1587	38
April	-	-	375.8	5.1	-	-	376	5
May	-	-	-	-	-	-	-	-
June	-	-	-	-	-	-	-	-
July	-	-	-	-	-	-	-	-
August	-	-	-	-	-	-	-	-
September	-	-	-	-	-	-	-	-
October	-	-	-	-	-	-	-	-
November	1657.0	27.1	-	-	-	-	1657	27
December	1521.0	0.0	-	-	-	-	1521	-
Total 2017	**5352.3**	**52.7**	**1962.9**	**42.7**	**-**	**-**	**7315**	**96**

[1]Injectant volumes indicate the volume delivered to the reservoir and do not include 263 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore
[2]Flow assurance solvent (FAS)

Table 2: Material Balance Data – Total Production

Produced Volumes[1] (m^3)	Bitumen	Water	Sol'n Gas	Propane	Flow Assurance Solvent
January	300	183	2724	689	62
February	262	253	2364	610	33
March	513	252	4177	529	34
April	469	177	3591	617	17
May	605	230	4626	590	10
June	485	268	7878	305	7
July	393	359	9131	242	5
August	324	399	8585	190	4
September	252	410	7082	146	3
October	245	446	7029	137	3
November	202	415	6789	105	3
December	93	252	2958	351	6
Total 2017	**4143**	**3644**	**66934**	**4511**	**187**

[1]Produced volumes indicate recovered from the reservoir and do not include 263 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 3: Material Balance Data – HW1 Production

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	241.8	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	108.1	66.3	3023.8	59.3	0.0
September	79.8	75.0	2235.4	44.5	0.0
October	77.5	61.4	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	4.7
Total 2017	**1276.3**	**516.0**	**20672.5**	**1667.6**	**49.6**

[1]Produced volumes indicate recovered from the reservoir and do not include 263 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 4: Material Balance Data – HW2 Production

Produced Volumes[1] (m^3)	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	15.6	0.0
April	50.0	2.6	518.4	371.6	0.0
May	276.6	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	1925.3	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 263 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 5: Material Balance Data – HW3 Production

Produced Volumes[1] (m^3)	Bitumen	Water	Sol'n Gas	Propane	Flow Assurance Solvent
January	171.5	5.0	1248.0	622.0	61.1
February	182.3	62.0	1079.3	170.3	17.4
March	219.0	123.2	2152.3	148.1	14.5
April	177.4	144.9	1395.4	99.4	9.8
May	162.9	146.4	1212.1	83.2	8.1
June	138.3	151.8	1865.6	71.5	6.6
July	102.9	180.6	1861.3	58.5	5.1
August	97.0	202.4	2821.2	55.3	4.2
September	80.9	206.0	2757.7	47.0	3.3
October	75.7	231.5	3290.3	47.1	3.0
November	90.3	234.4	4363.7	50.2	2.5
December	55.8	151.6	2248.7	30.0	1.7
Total 2017	**1554.0**	**1839.8**	**26295.6**	**1482.6**	**137.3**

[1]Produced volumes indicate recovered from the reservoir and do not include 263 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 6: 2016 Material Balance Data – Total Production Corrected with Sample Analysis Data

Produced Volumes[1] (m^3)	Bitumen	Water	Sol'n Gas	Propane	Flow Assurance Solvent
January	102	19	475	96	13
February	207	288	3435	108	12
March	163	139	1123	219	31
April	338	61	4390	638	109
May	434	197	3751	364	46
June	274	219	2894	380	50
July	623	201	4985	630	67
August	429	334	4223	244	22
September	205	270	1918	107	14
October	379	391	3693	558	12
November	336	389	4302	189	10
December	160	84	1539	445	26
Total 2016	**3650**	**2592**	**36728**	**3978**	**412**

[1]Produced volumes indicate recovered from the reservoir and do not include 446 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 7: 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 8: 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 9: 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 Sm3/D

Table 10: Price Assumptions for Revenue Calculations

	Bitumen $/bbl	Natural Gas $/mcf	Propane[1] $/bbl	Pilot Flow Assurance Solvent[1] $/bbl
2017	$39.13	$2.58	$49.83	$72.74

[1]Average price paid for the CSP pilot for 2017

Table 11: Cumulative Project Revenue

Cumulative Revenue (k$)	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Bitumen	0	0	0	0	0	18	194	593	1,020	1,825
Solution Gas	0	0	0	0	0	0	0	3	6	9
Recovered Propane	0	0	0	0	0	22	105	503	1,414	2,044
Recovered Diluent	0	0	0	0	0	294	26	0	0	320
Recovered Flow Assurance Solvent	0	0	0	0	0	0	410	293	215	918
Total Revenue	**0**	**0**	**0**	**0**	**0**	**334**	**735**	**1392**	**2655**	**5116**

[1] Estimated, see section 8.2 for assumptions

Table 12: Drilling and Facilities Costs

Drilling and Facilities Costs (k$)	**2017**
Preliminary Engineering	0
Surface Facilities	0
OB Well Drilling	0
HW Drilling	0
Completions	0
Geo Surveillance	0
Total Drilling and Facilities Costs	0

Table 13: Operating Costs

Direct and Indirect Operating Costs (k$)	**2017**
Operating Costs	3,245
Total	**3,245**

Table 14: Injectant Costs

Injectant Costs (k$)	**2017**
Propane	2,426
Flow assurance solvent	180
Total	**2,606**

Table 15: Cumulative Project Costs

Cumulative Costs (k$)	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Drilling & Facilities Costs	563	1,631	8,991	33,257	22,776	4,591	77	-7	0	71,879
Operating Costs	0	0	0	0	0	1,649	2,103	3,385	3,245	7,137
Injectant Costs	0	0	0	0	0	776	846	2027	2,606	3649
Total Costs	**563**	**1,631**	**8,991**	**33,257**	**22,776**	**7,016**	**3,026**	**5,405**	**5,851**	**82,665**

Table 16: Estimated Crown Royalty Calculation

Crown Royalties (k$)	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Pilot Revenue[1]	0	0	0	0	0	334	735	1,392	2,655	2,461
Pilot Costs[2]	563	1,631	8,991	33,257	22,776	7,016	3,026	5,405	5,851	82,665
ERA (Formerly CCEMC) Credit[3]				2,400	2,480	480	960	1,680	0	8,000
Before Royalty Cash Flow	-563	-1,631	-8,991	-30,857	-20,296	-6,202	-1,331	-2,333	-3,196	-72,204
Cold Lake Royalty Rate[4]	27.8%	30.9%	33.8%	34.2%	35.4%	36.8%	27.2%	25.2%	27.4%	-
Cold Lake Royalty Impact	-156	-504	-3,039	-10,553	-7,185	-2,282	-362	-587	-876	-24,668
Total Cold Lake Royalties[4]	438,240[5]	628,605[5]	935,665[5]	678,964[5]	599,433	772,086	228,198	247,787	440,408	-

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

Figures

Figure 1: Well Layout

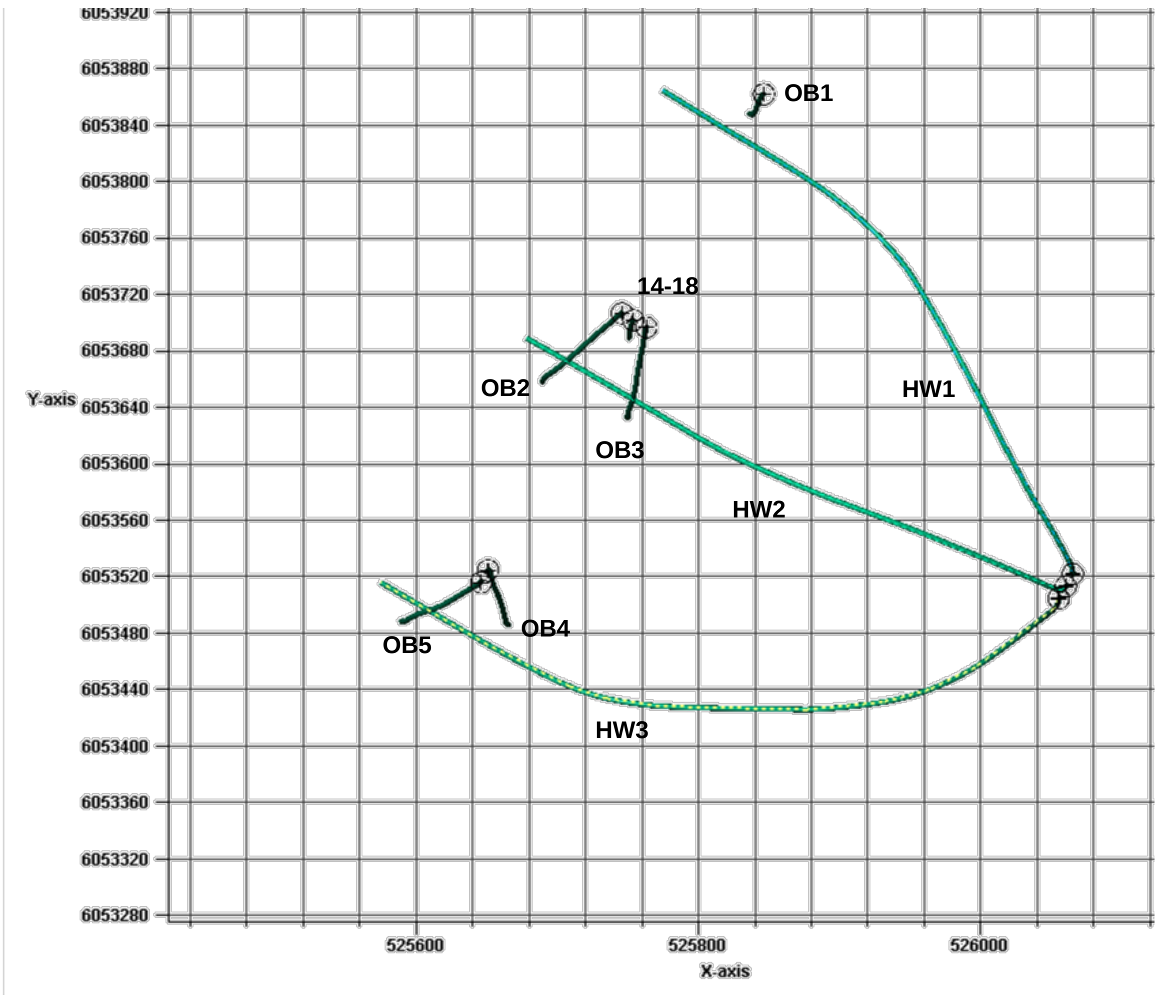


Figure 2: Surface Facility and Pad Locations

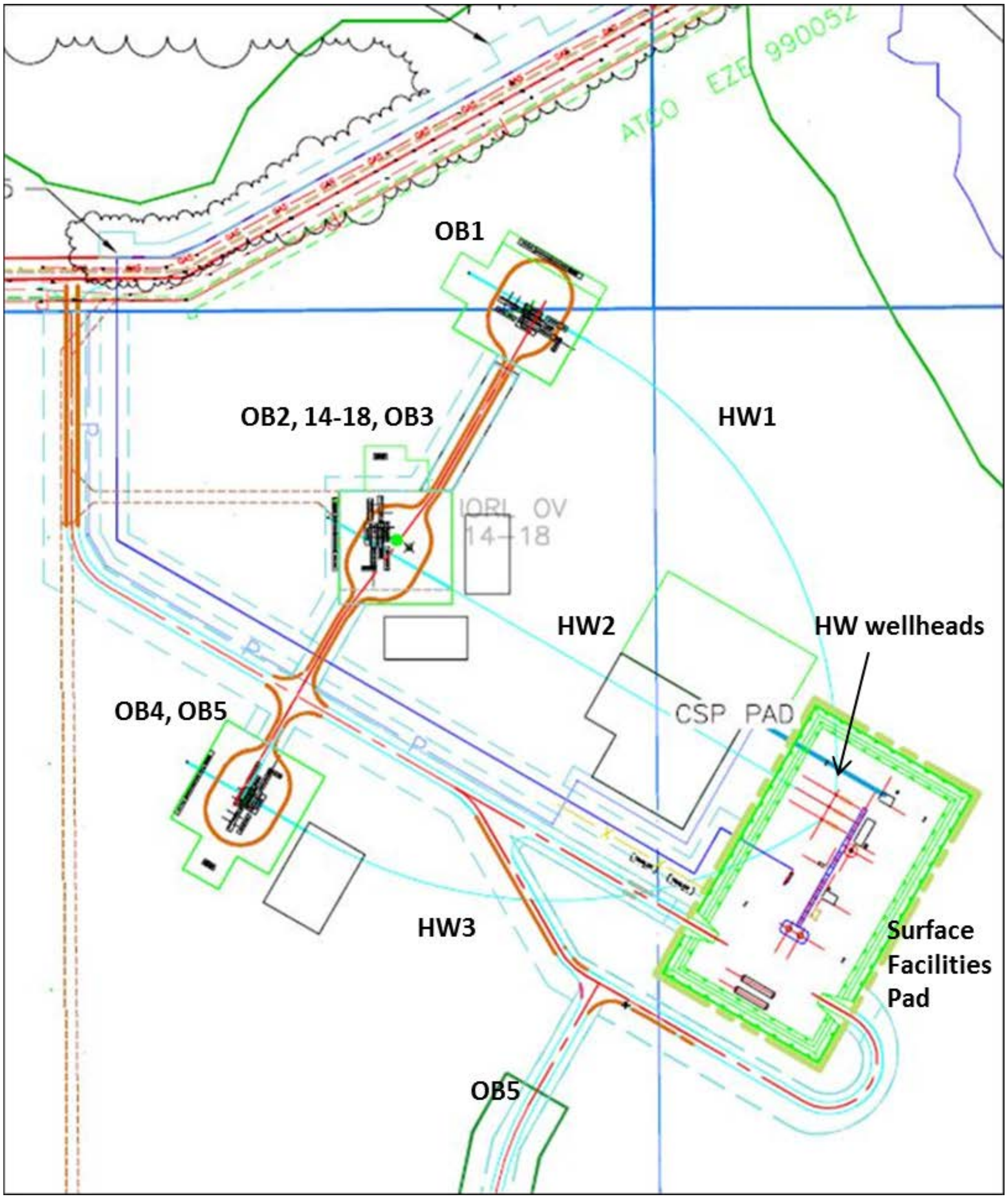


Figure 3: Log Cross Section of Pilot Area through OB Wells

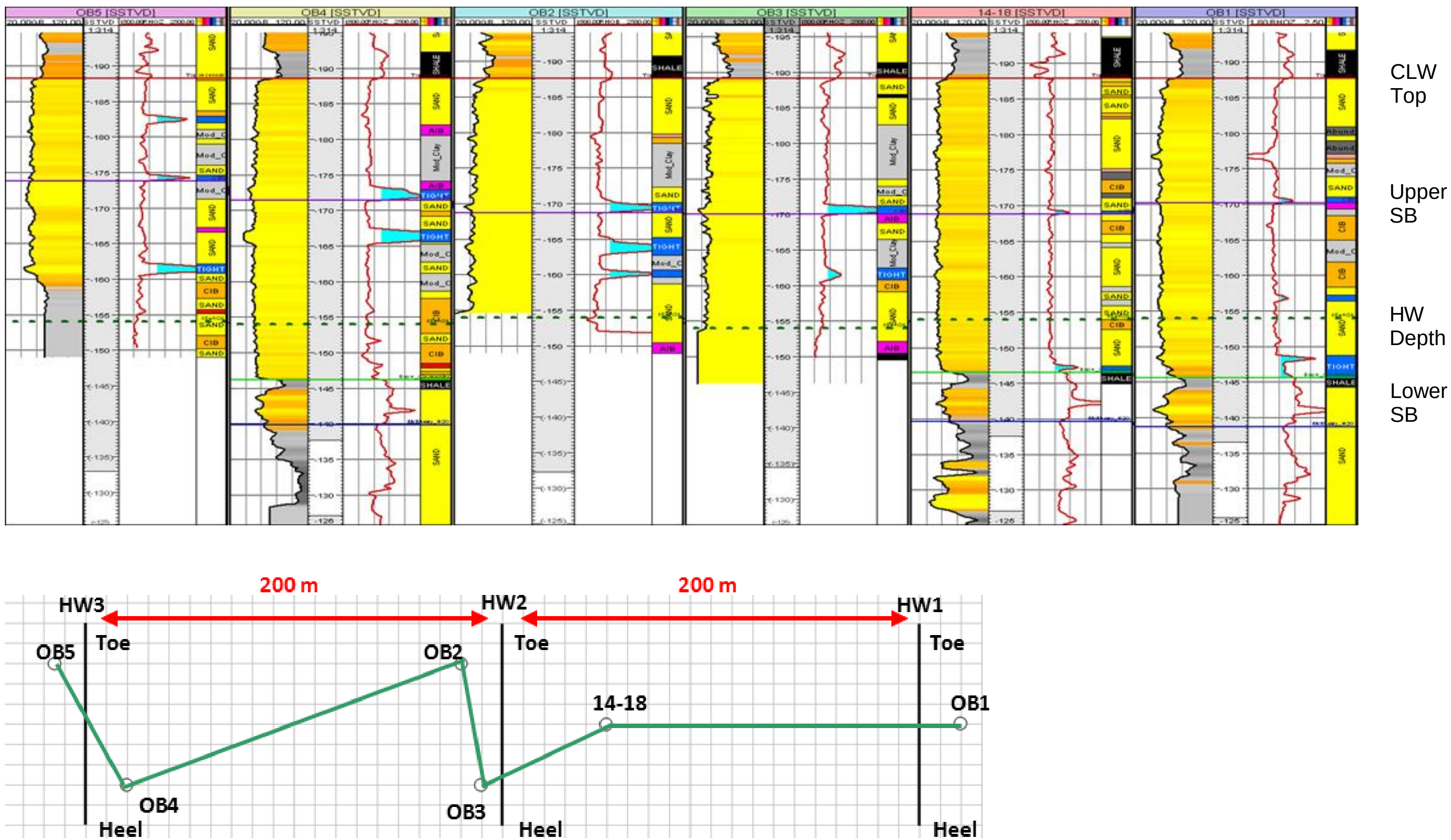
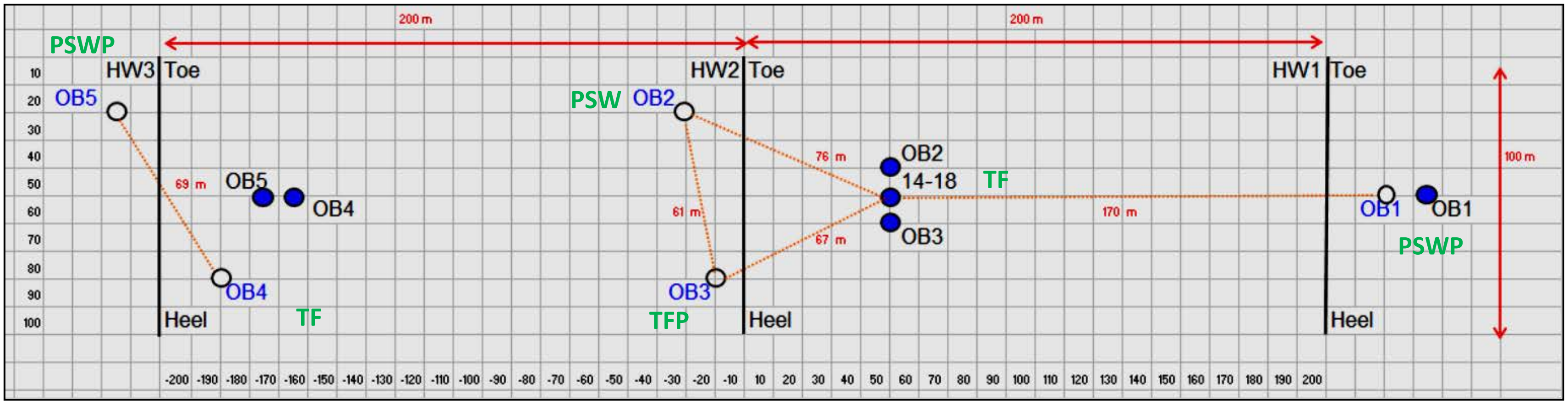


Figure 4: OB Wells Location and Surveillance Instrumentation



● Surface Location ○ Bottom Hole

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 5: CSP Horizontal Well Schematic

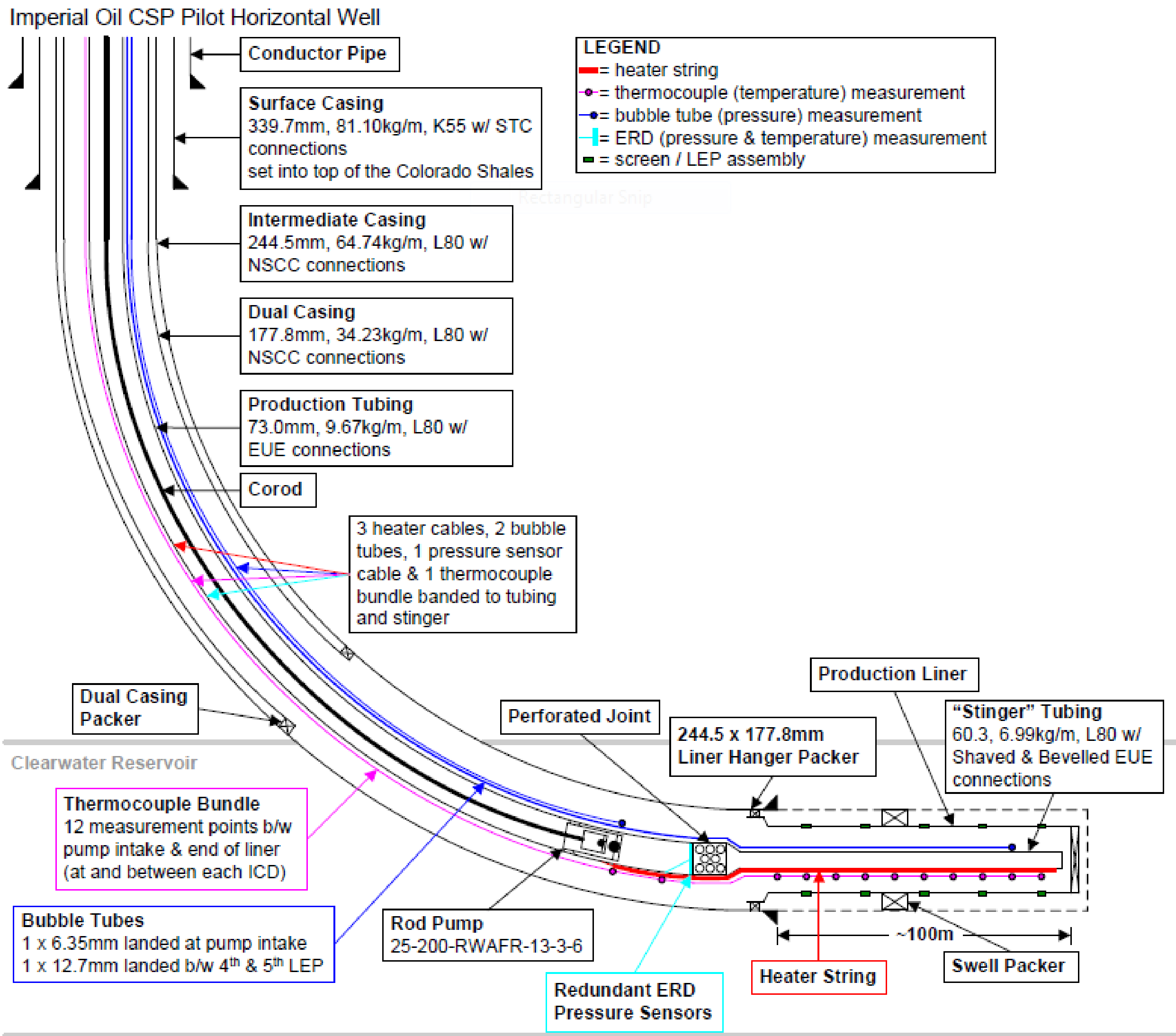


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Figure 6: CSP Pilot Site View

Figure 7: Characteristic Curve Shapes of CSP Components in C30+

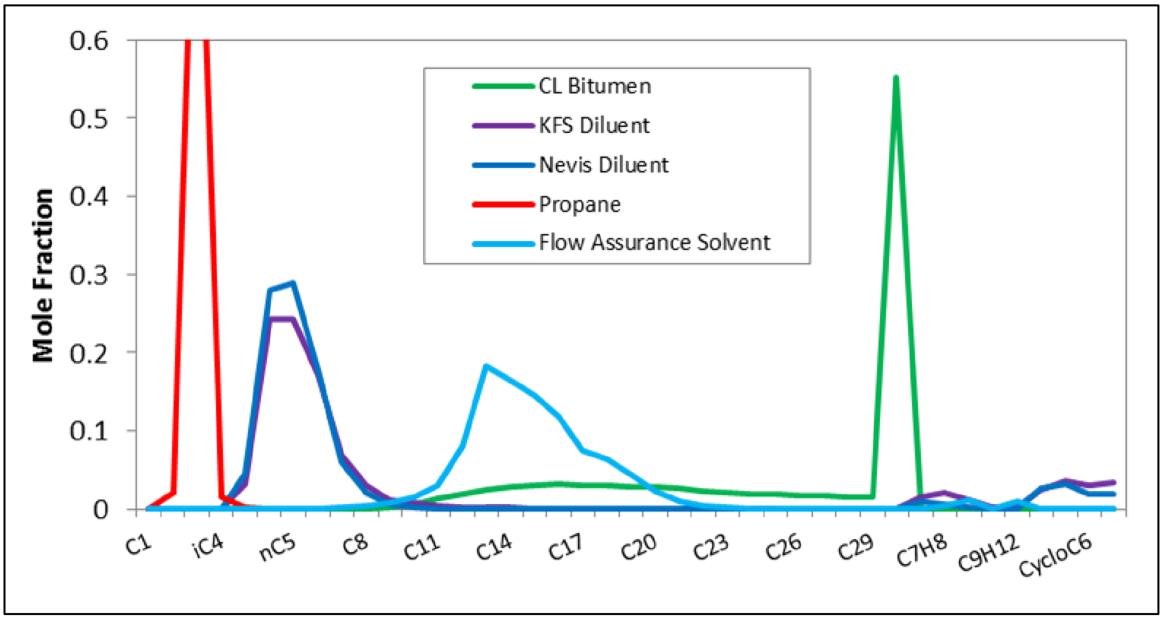
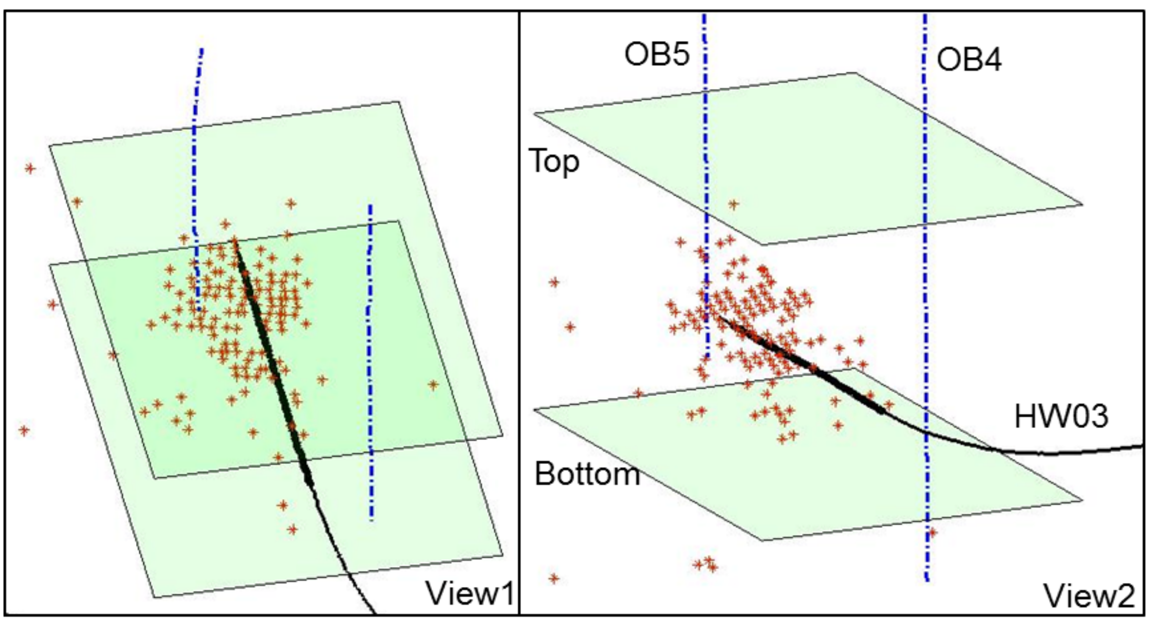
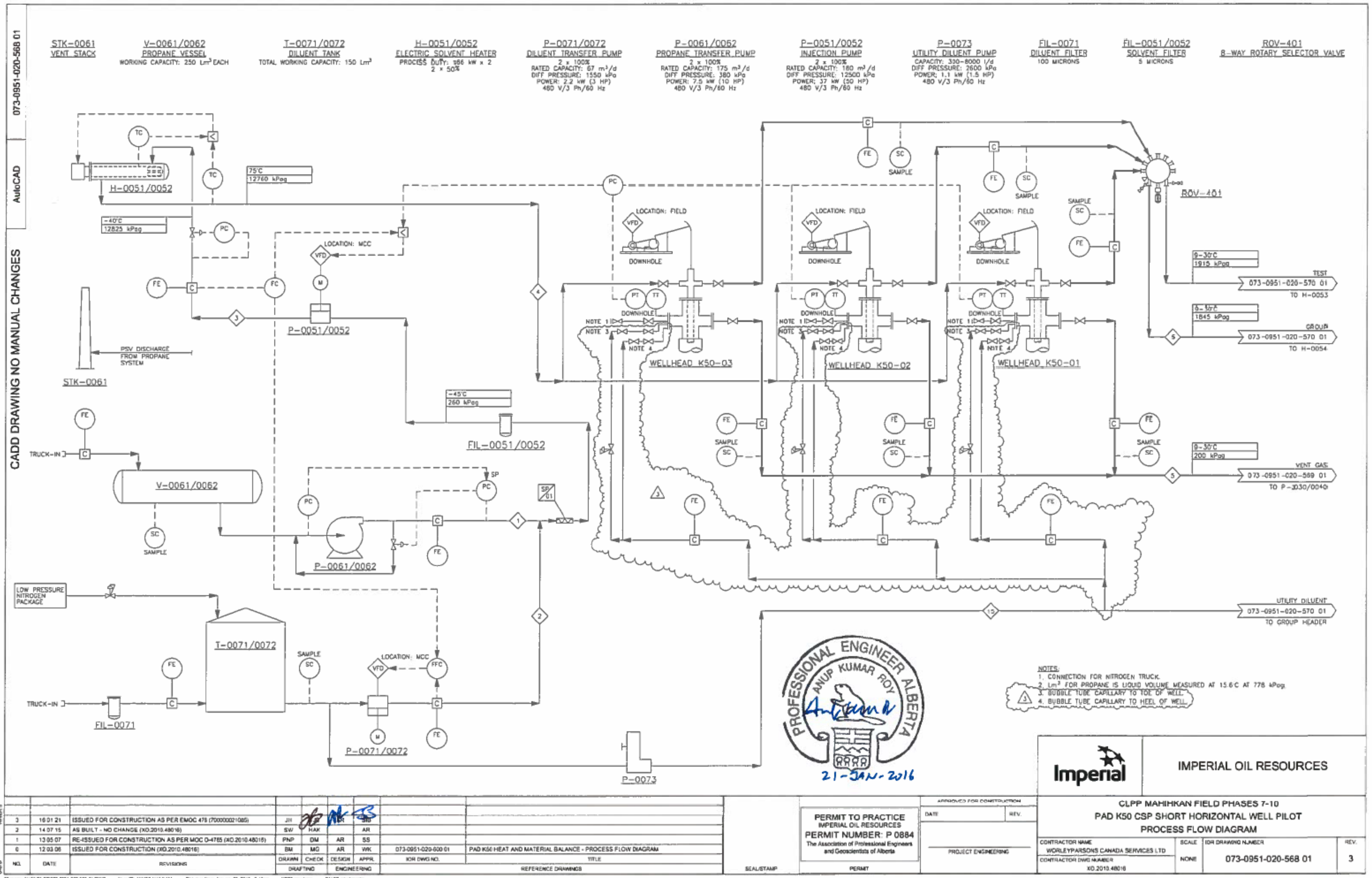


Figure 8: Passive Seismic Event Locations for HW3 Cycle 1



Appendix A: Process Flow Diagrams (PFDs)



STK-0061 VENT STACK
V-0061/0062 PROPANE VESSEL
T-0071/0072 DILUENT TANK
H-0051/0052 ELECTRIC SOLVENT HEATER
P-0071/0072 DILUENT TRANSFER PUMP
P-0061/0062 PROPANE TRANSFER PUMP
P-0051/0052 INJECTION PUMP
P-0073 UTILITY DILUENT PUMP
FIL-0071 DILUENT FILTER
FIL-0051/0052 SOLVENT FILTER
ROV-401 8-WAY ROTARY SELECTOR VALVE
WELLHEAD K50-03
WELLHEAD K50-02
WELLHEAD K50-01
NOTES:
1. CONNECTION FOR NITROGEN TRUCK.
2. Lm³ FOR PROPANE IS LIQUID VOLUME MEASURED AT 15.6°C AT 778 kPag.
3. BUBBLE TUBE CAPILLARY TO TOE OF WELL.
4. BUBBLE TUBE CAPILLARY TO HEEL OF WELL.
IMPERIAL OIL RESOURCES
PERMIT TO PRACTICE
IMPERIAL OIL RESOURCES
PERMIT NUMBER: P 0884
The Association of Professional Engineers and Geoscientists of Alberta
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
073-0951-020-568 01
REV.
3
21-JAN-2016

073-0951-020-569 01

AutoCAD

CADD DRAWING NO MANUAL CHANGES

V-0003
LIQUID SEPARATOR
SIZE: 736 mm I.D. x 2550 mm S/S

T-0023
MAKE-UP WATER TANK
WORKING CAPACITY: 6.4 m^3

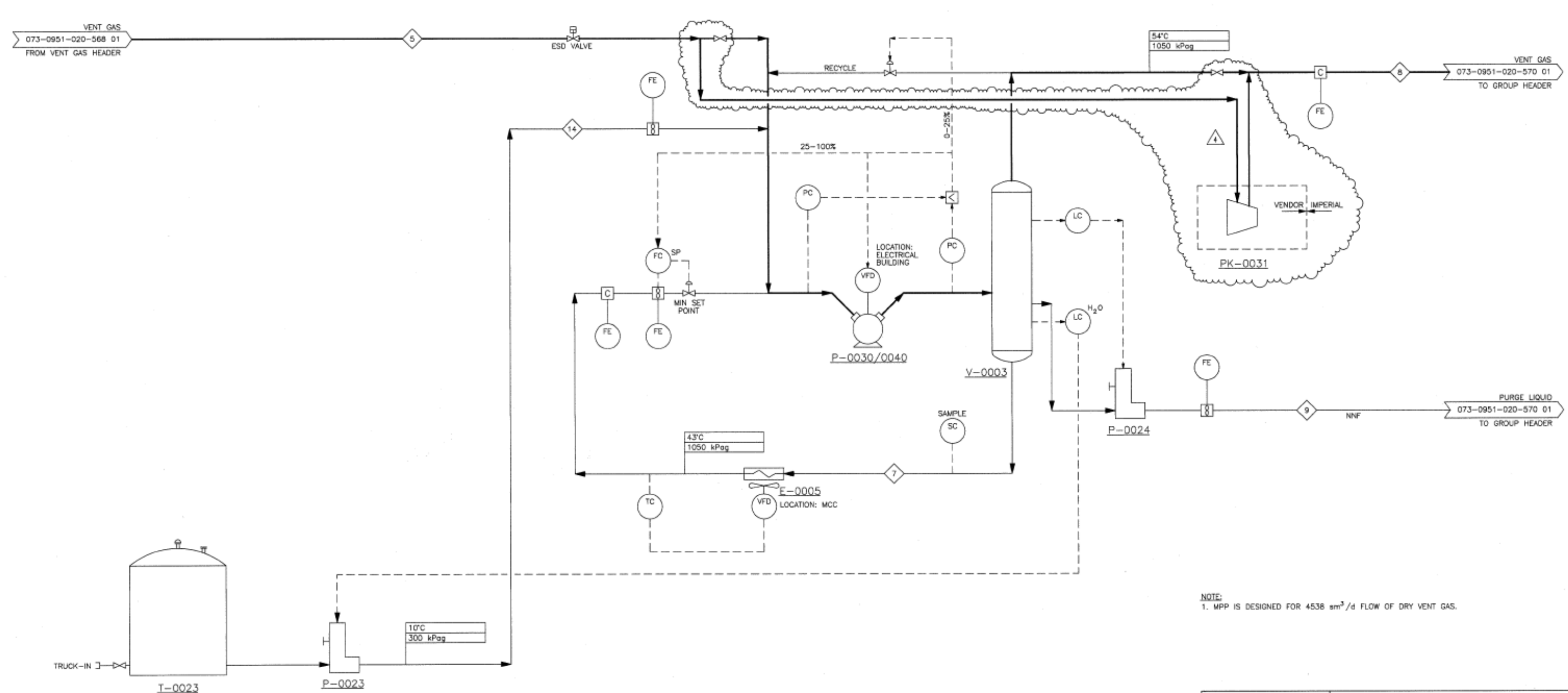
P-0030/0040
MULTI PHASE VENT GAS PUMP
CAPACITY: 153 m^3/hr (ACTUAL)
SUCTION CONDITIONS:
TEMPERATURE: 42°C
PRESSURE: 70 kPag
DENSITY: 49.4 kg/m^3
POWER: 93 kW (125 HP)
2 x 100%
NOTE 1

E-0005
RECYCLE LIQUID COOLER
PROCESS DUTY: 203 kW

P-0023
MAKE-UP WATER PUMP
RATED CAPACITY: 0-100 l/h
DIFF PRESS: 350 kPa
POWER: 0.74 kW (1 HP)
480 V/3 Ph/60 Hz

P-0024
PURGE LIQUIDS PUMP
RATED CAPACITY: 0-1000 l/h
DIFF PRESS: 1500 kPa
POWER: 2.2 kW (3 HP)
480 V/3 Ph/60 Hz

4
PK-0031
PORTABLE COMPRESSOR
RATED CAPACITY: 1007-3029 sm^3/d
DIFF PRESS: 2600 kPa
POWER: 22.4 kW (30 HP)
480 V/3 Ph/60 Hz



NOTE:
1. MPP IS DESIGNED FOR 4538 sm^3/d FLOW OF DRY VENT GAS.

NO.	DATE	REVISIONS	DRAWN	CHECK	DESIGN	APPR.
4	15 09 24	ISSUED FOR CONSTRUCTION AS PER EMOC-386 (700000021085)	EJ	FJB		SYJ
3	14 07 15	AS BUILT - NO CHANGE (XO.2010.48016)	SW	HAK		AR
2	12 10 31	RE-ISSUED FOR CONSTRUCTION AS PER MOC O-7333 (XO.2010.48016)	BM	RG	AR	SS
1	12 08 22	RE-ISSUED FOR CONSTRUCTION AS PER MOC O-7185 (XO.2010.48016)	BM	MG	AR	SS
0	12 03 06	ISSUED FOR CONSTRUCTION (XO.2010.48016)	BM	MG	AR	WK

DRAFTING — ENGINEERING

IOR DWG NO.	TITLE
073-0951-020-600 01	PAD K50 HEAT AND MATERIAL BALANCE - PROCESS FLOW DIAGRAM

REFERENCE DRAWINGS

Version: 5 D-STD

Filename: Y:\FILENET\073-0951-020-569-01.DWG User ID: ENIKO.JOO Plot date/time: September 28, 2015 1:00pm XREF drawings: IMAGE attachments:

PROFESSIONAL ENGINEER ALBERTA
SEAL/STAMP
28-Sept-2015 Rev 4 only

PERMIT TO PRACTICE
IMPERIAL OIL RESOURCES
Signature
Date Sept. 28, 2015
PERMIT NUMBER: P 0884
The Association of Professional Engineers and Geoscientists of Alberta
PERMIT

APPROVED FOR CONSTRUCTION
DATE 2015 09 28 REV. 4
PROJECT ENGINEERING

Imperial

IMPERIAL OIL RESOURCES

CLPP MAHIHKAN FIELD PHASES 7-10
PAD K50 CSP SHORT HORIZONTAL WELL PILOT
PROCESS FLOW DIAGRAM

CONTRACTOR NAME	SCALE	IOR DRAWING NUMBER	REV.
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CONTRACTOR DWG NUMBER XO.2010.48016			

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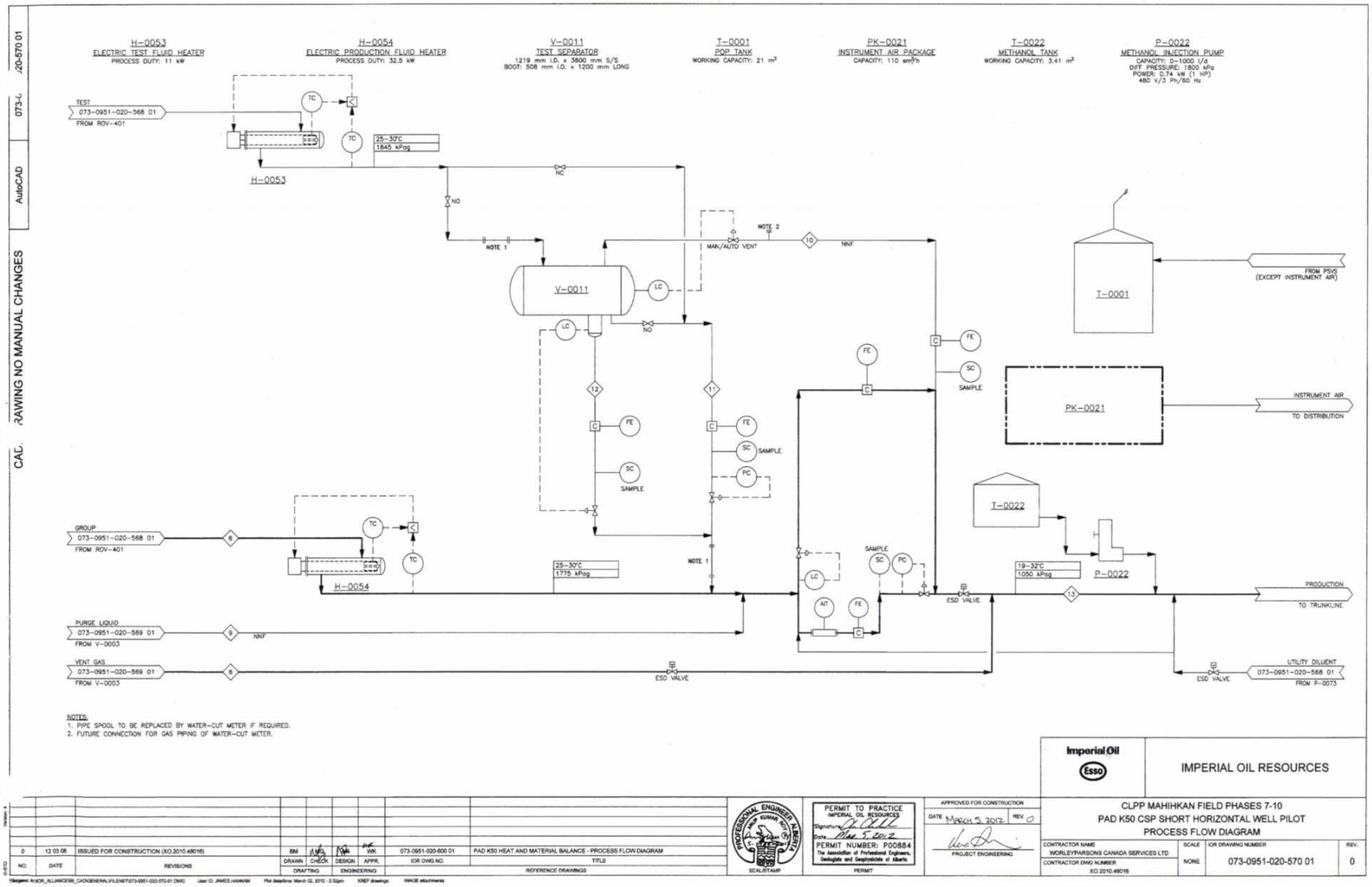

H-0053
ELECTRIC TEST FLUID HEATER
PROCESS DUTY: 11 kW
H-0054
ELECTRIC PRODUCTION FLUID HEATER
PROCESS DUTY: 32.5 kW
V-0011
TEST SEPARATOR
1219 mm I.D. x 3800 mm S/S
BOOT: 508 mm I.D. x 1200 mm LONG
T-0001
POP TANK
WORKING CAPACITY: 21 m³
PK-0021
INSTRUMENT AIR PACKAGE
CAPACITY: 110 sm³/h
T-0022
METHANOL 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)
480 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
ESD VALVE
NOTE 1
NOTE 2
MAN/AUTO VENT
NNF
SAMPLE
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
NOTES:
1. PIPE SPOOL TO BE REPLACED BY WATER-CUT METER IF REQUIRED.
2. FUTURE CONNECTION FOR GAS PIPING OF WATER-CUT METER.
Imperial Oil
Esso
IMPERIAL OIL RESOURCES
CLPP MAHIHKAN FIELD PHASES 7-10
PAD K50 CSP SHORT HORIZONTAL WELL PILOT
PROCESS FLOW DIAGRAM
PERMIT TO PRACTICE
IMPERIAL OIL RESOURCES
Date Mar 5, 2012
PERMIT NUMBER: P00884
The Association of Professional Engineers, Geologists and Geophysicists of Alberta
APPROVED FOR CONSTRUCTION
DATE MARCH 5, 2012 REV. 0
PROJECT ENGINEERING
CONTRACTOR NAME
WORLEYPARSONS CANADA SERVICES LTD
CONTRACTOR DWG NUMBER
XO.2010.48016
SCALE NONE
IOR DRAWING NUMBER 073-0951-020-570 01
REV. 0
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. IOR DWG NO. TITLE
DRAFTING ENGINEERING REFERENCE DRAWINGS
SEAL/STAMP PERMIT
073-0951-020-570 01
AutoCAD
CAD DRAWING NO MANUAL CHANGES