IETP Application No. 03-047

Imperial Oil Resources - Cold Lake Solvent Assisted - SAGD Pilot

Final Project Technical Report

Confidential under IETP Agreement

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1 Abstract

Imperial Oil Resources (Imperial) is conducting a Solvent Assisted - Steam Assisted Gravity Drainage (SA-SAGD) experimental pilot scheme at Cold Lake in the Clearwater formation to be operated under Alberta Energy and Utilities Board (AEUB) Approval 10689, dated October 30, 2006.

The experimental process design for the pilot involves the addition of hydrocarbon solvent (diluent) volume in the range of 5-20% of dry steam volume, along with the injected steam in a dual horizontal well SAGD configuration. Work performed by the Alberta Research Council (ARC)[1] and by Imperial indicates that the addition of solvent to the steam results in increased bitumen rates and decreased steam-oil ratios relative to the conventional SAGD process. The ES-SAGD process has been patented by ARC and Imperial has use rights to the technology through partial funding of the development work.

The pilot includes two horizontal well-pairs (four wells), six observation wells, associated steam and diluent injection facilities, artificial lift, as well as production measurement and testing facilities. The SA-SAGD pilot uses existing steam generation, water treatment, bitumen separation and processing facilities at Imperial's Mahkeses plant, as well as the existing steam distribution and production gathering system.

This report summarizes progress that was made from November 2009 to year end 2013 (end of pilot), including a final seismic shoot in March 2014. Pilot operations started with well-pair 1 operating in SAGD mode, while the adjacent well-pair 2 operating in SA-SAGD mode. On May 2012, there was a solvent switch at T13, converting well-pair 1 to SA-SAGD mode, and well-pair 2 to SAGD mode.

[1] Nasr, T.N., Beaulieu, G., Golbeck, H., and Heck, G.: "Novel Expanding Solvent - SAGD Process "ES-SAGD"", JCPT January 2003, Volume 42, and No. 1.

2 Summary Project Status Report

2.1 Members of the project team

The following are key members of the SA-SAGD team:

John F. Elliott, P.Eng. – Manager, Oil Sands Recovery Research
Dale Fair, P.Eng – SA-SAGD Pilot Team Lead (former)
Liza Monette – SA-SAGD Pilot Team Lead (current)
Gloria Adeleke – SA-SAGD Pilot Technologist
Aisha Hammouda, P.Eng – SA-SAGD Pilot Engineer

2.2 Key activities

The following is a list of key pilot activities from 2008 to 2013:

2008: Baseline seismic
November 17, 2009: First steam-in, SAGD circulation phase begun into both well-pairs
December 7, 2009: Pad shut in due to facility issues
December 19, 2009: Re-started steam injection
December 7, 2009 - January 29, 2010: Pad shut in due to surface facility issues
January 30, 2010: Warm-up phase recommenced
June 30, 2010: Warm-up phase successfully completed, pad shut-in
July 20, 2010: Pad restarted under SAGD mode
October 20, 2010: Diluent injection commenced into T13-04, converting well-pair 2 to SA-SAGD mode (well-pair 1 continues in SAGD mode)
November 25: December 22, 2010: Diluent injection shut-in due to surface facility issues (well-pair 2 continued to operate in SAGD mode)
March, 2012: 4D Seismic shoot
May 28, 2012: Well-pair modes were switched, well-pair 1 operated in SA-SAGD mode, and well-pair 2 operated in SAGD mode
September 21, 2012: Injection shut in due to routine maintenance work on main steam line from Mahkeses plant. Both well-pairs were shut in and did not produce during this time, with injection resuming on October 2, 2012
July – October, 2013: Diluent quality issues resulting in diluent injection shut in during these periods on well-pair 1
March, 2014: 4D seismic shoot

2.3 Production, and material and energy balance flow sheets

Gross balances

Steam:

Steam for the SA-SAGD pilot was generated at the Mahkeses plant in Cold Lake, which falls outside of the IETP project scope. Summary of injected steam volumes (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
2009	1384.9	1343.7	1176.1	1377.1
2010	7882.7	29308.1	6976.4	30693.3
2011	0.0	50534.0	0.0	56991.4
2012	0.0	55484.9	0.0	62673.2
2013	0.0	54781.5	0.0	48774.6

Produced Materials

Produced water (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
2009	356.3	514.6	549.0	681.6
2010	27420.6	5190.4	31923.1	4807.1
2011	46645.3	0.0	54395.6	0.0
2012	51420.7	0.0	58605.6	0.0
2013	50913.6	0.0	45686.0	0.0

Volume disposed:

- There are no disposal wells included in this IETP project.

Produced hydrocarbon liquid (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
2009	0.0	0.0	0.0	0.0
2010	5420.5	358.2	7489.1	377.8
2011	13785.2	0.0	21049.9	0.0
2012	16686.6	0.0	18392.4	0.0
2013	22767.0	0.0	10760.3	0.0

- The standard API of Cold Lake oil is 11.
- Produced hydrocarbon liquid volumes include liquid hydrocarbon from both the liquid and vent gas separators.
- Volumes in both T13-01 and T13-03 include diluent recovered in the oil liquid phase. A breakdown is provided in Section 4.1.

Diluent (purchased, in m^3):

	T13
2010	1371.2
2011	8105.2
2012	10835.8
2013	7725.0

- These volumes represent diluent that was purchased and stored on site at T13 (inside the diluent tank).

Summary of injected diluent volumes (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
2009	0.0	0.0	0.0	0.0
2010	0.0	0.0	0.0	1207.3
2011	0.0	0.0	0.0	7973.9
2012	0.0	6533.8	0.0	4194.5
2013	0.0	7487.3	0.0	0.0

Produced Sand (m^3):

- Sand production is not measured at the pilot, and any sand production is assumed to be negligible.

Produced gas (by well, in 10^3m^3):

	T13-01	T13-02	T13-03	T13-04
2009	0.0	0.0	0.0	0.0
2010	40.7	2.6	57.1	3.2
2011	155.3	0.0	347.4	0.0
2012	51.7	0.0	26.1	0.0
2013	86.6	0.0	42.1	0.0

Pilot set up at T13 is unique, as it is tied back to Mahkeses plant, which utilizes Heat Recovery Steam Generation (HRSG), and serves other CSS pads along with the pilot. For that reason, SA-SAGD metrics [such as electricity consumed, boiler steam details, in-situ combustion and process air and fresh water] and any incremental over SAGD, cannot be accurately determined for this project.

2.4 Reserves

The current estimate of expected recovery is 40 to 50% of Original Bitumen in Place (OBIP). OBIP on T13 pad is 1,062,000 m^3. Note that this estimate is associated with SAGD only, as solvent assisted recovery uplift needs further assessment to support additional reserves booking.

3 Well Information

3.1 Well Layout Map

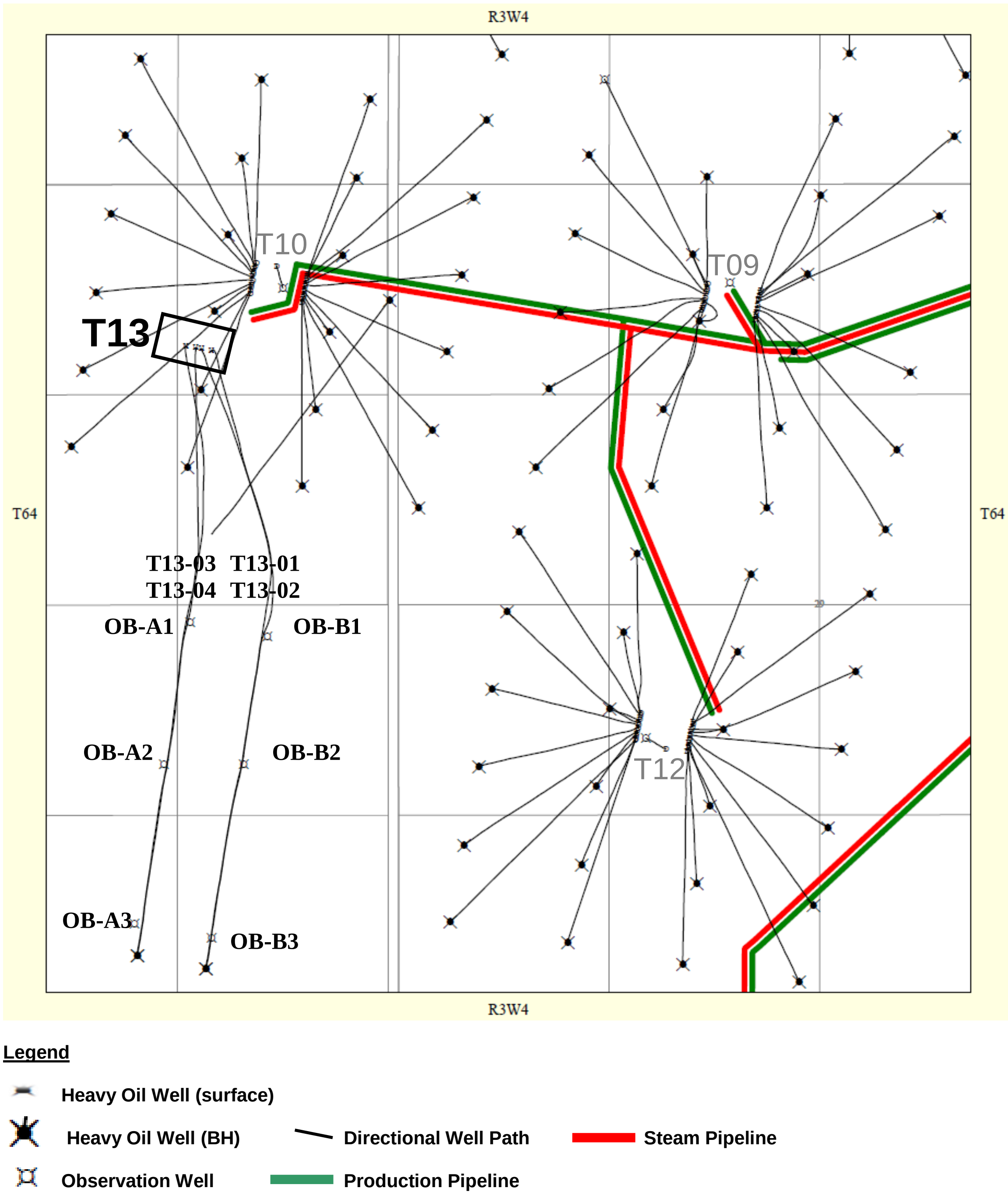


Figure 1: Location of SA-SAGD surface facilities and well trajectories

3.2 Drilling, completion, and work-over operations

Drilling and completion work on the four horizontal wells was completed in 2008, and all six observation wells were drilled in the 2006-2007 timeframe.

3.3 Well operation

All four horizontal wells (T13-01, 02, 03, 04) started steam injection on November 17, 2009. The wells continued to operate in warm-up mode until June 30, 2010. On July 20, 2010, SAGD mode was initiated on both well-pairs. On October 20, 2010, solvent injection commenced into well T13-04, thus initiating SA-SAGD operation on the west well pair (well-pair 2). On May 28, 2012, the well-pairs went through a solvent switch, turning well-pair 2 to SAGD operation, and well-pair 1 to SA-SAGD operation.

As skin developed on the well-pairs' producers, there were a number of well stimulation jobs in 2012 and 2013:

Start Date	End Date (if applicable)	Stimulation Job
1-Feb-13	1-May-14	1 Water flush on T13-01 and 8 Water/N2 flushes on T13-03
8-Feb-13		Acid job on T13-03
8-Mar-13		Acid job on T13-01
15-Aug-13		Acid job on T13-03
21-Nov-13		Acid job on T13-01
25-Jan-14		CTU (coil tubing unit) acid job on T13-03
22-Apr-14		Acid job on T13-01
8-Jun-14		Perforation job on T13-03

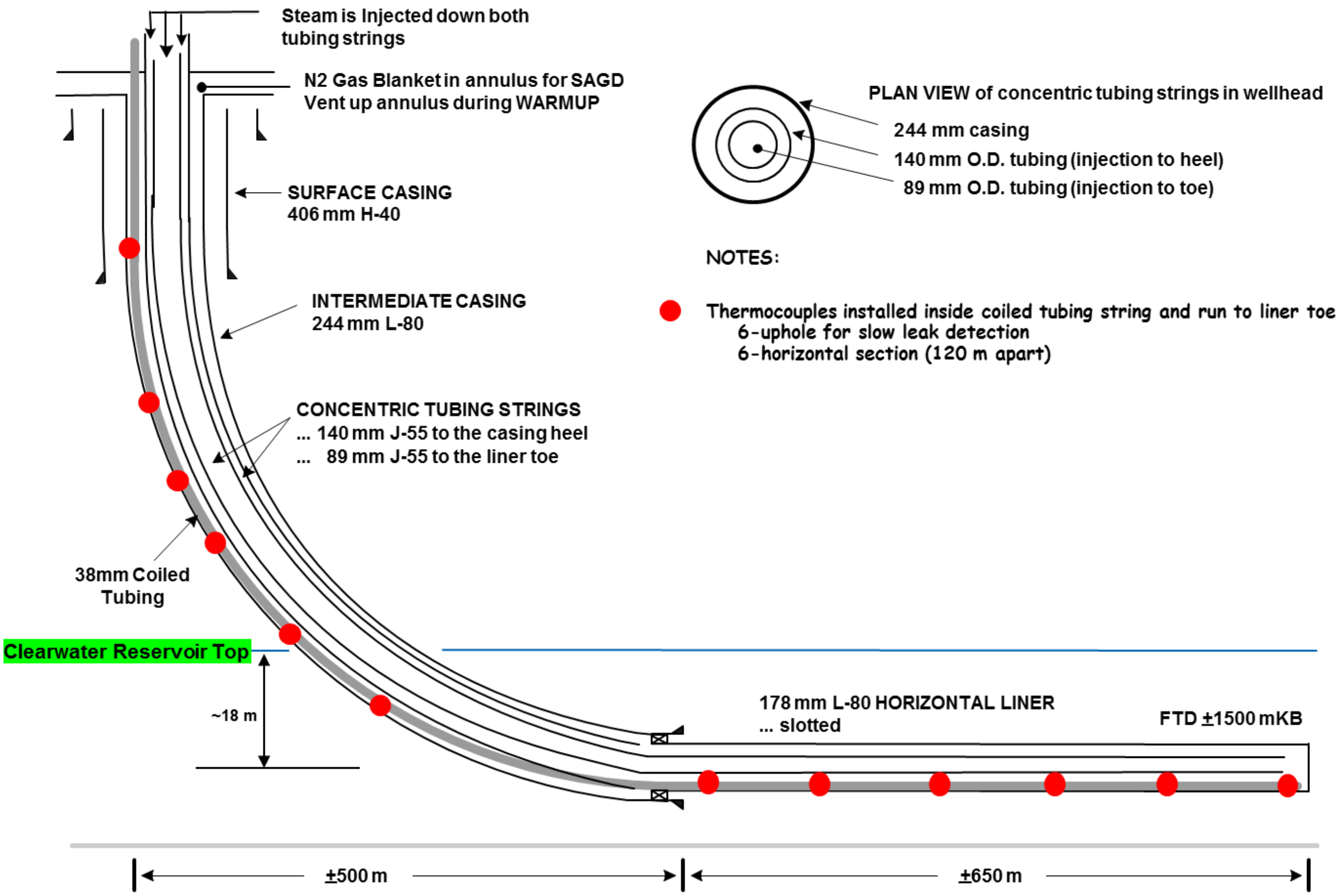
3.4 Well list and status

All wells are currently active. List as follows:

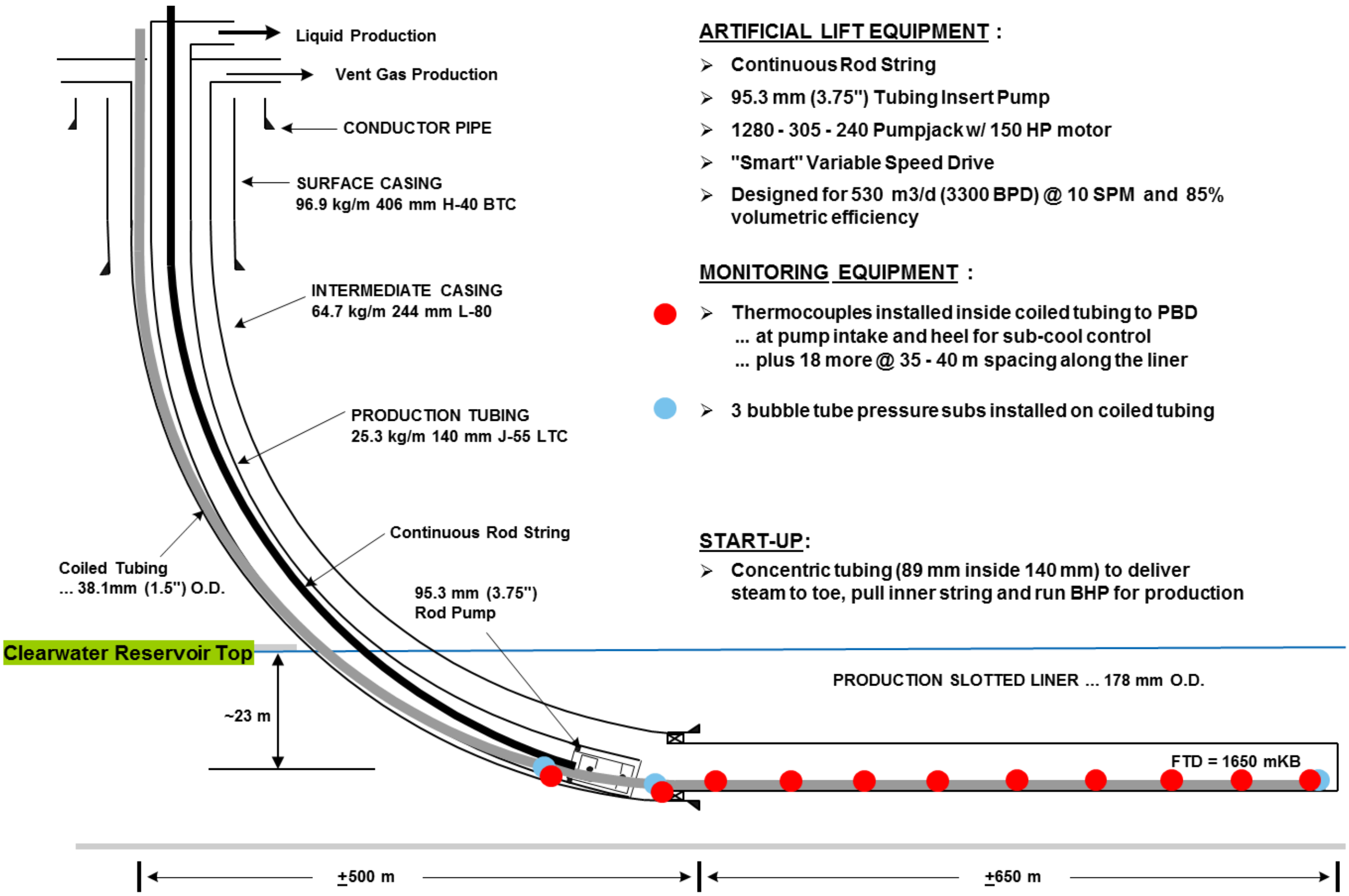
East well-pair	1AB/01-30-064-03W4/0 (**T13-01**) producer 1AC/01-30-064-03W4/0 (**T13-02**) injector 1AA/08-30-064-03W4/0 (**OB-B1**) observation well 1AD/08-30-064-03W4/0 (**OB-B2**) observation well 1AA/01-30-064-03W4/0 (**OB-B3**) observation well
West well-pair	1AB/02-30-064-03W4/0 (**T13-03**) producer 1AC/02-30-064-03W4/0 (**T13-04**) injector 1AB/08-30-064-03W4/0 (**OB-A1**) observation well 1AA/07-30-064-03W4/0 (**OB-A2**) observation well 1AA/02-30-064-03W4/0 (**OB-A3**) observation well

3.5 Wellbore schematics

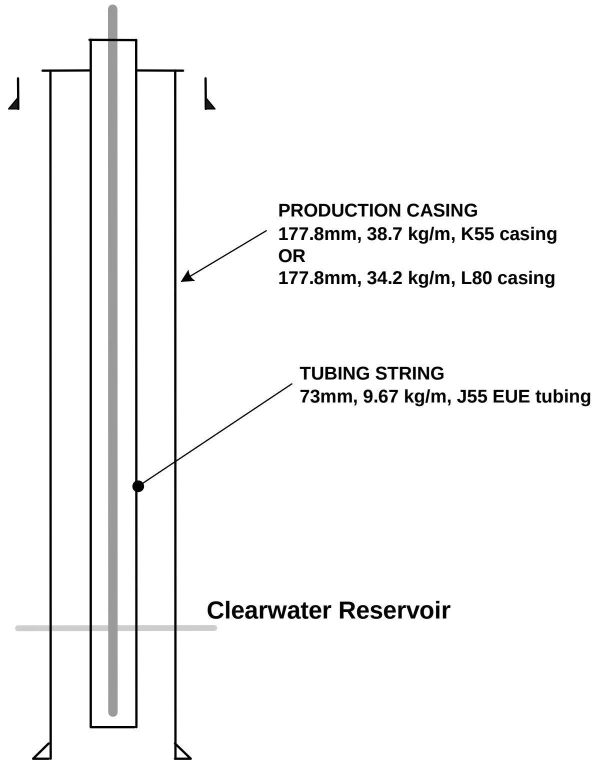
SAGD/SA-SAGD Injectors:



SAGD/SA-SAGD Producers:



All six observation wells are completed as follows (fitted with thermocouple bundles installed inside the 73 mm tubing string):



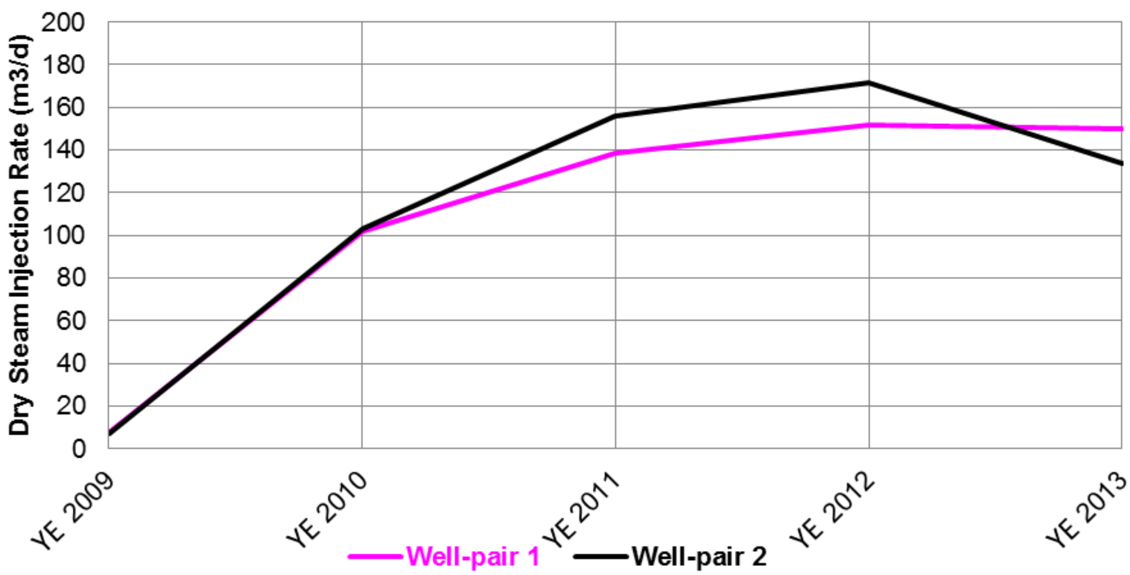
3.6 Spacing and pattern

The horizontal well-pairs are spaced approximately 150 m apart, with approximately 650 m of drainage length per well. This translates into a drainage pattern of approximately 97,500 m^2 (150m * 650m), which is roughly 24 acres per well.

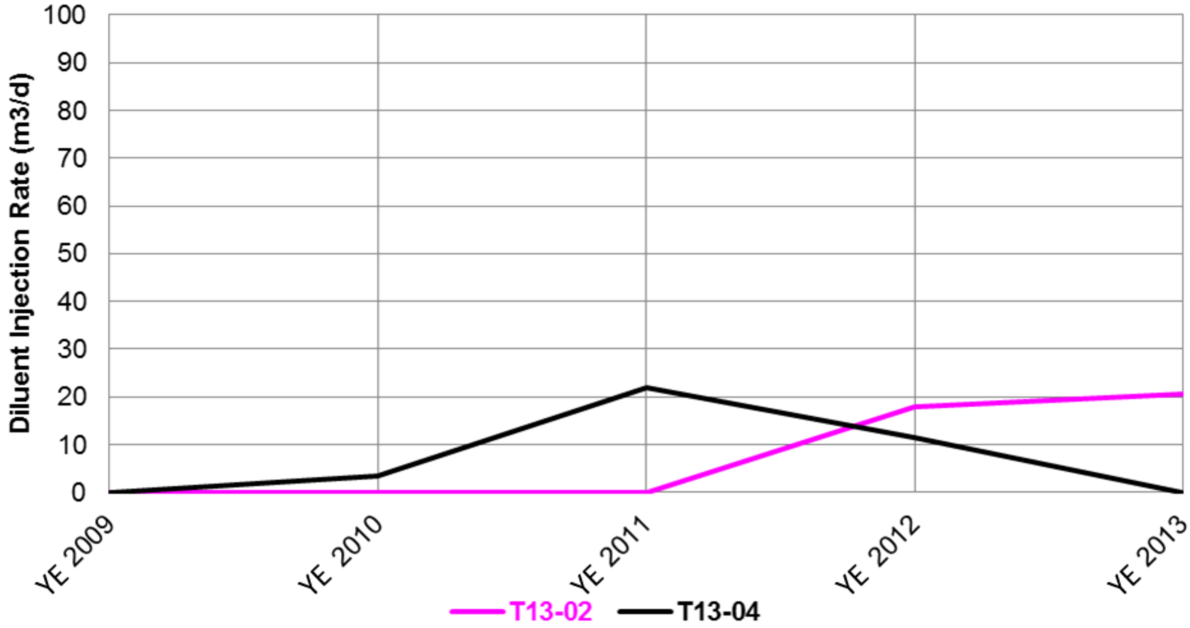
4 Production Performance

4.1 Injection and production history

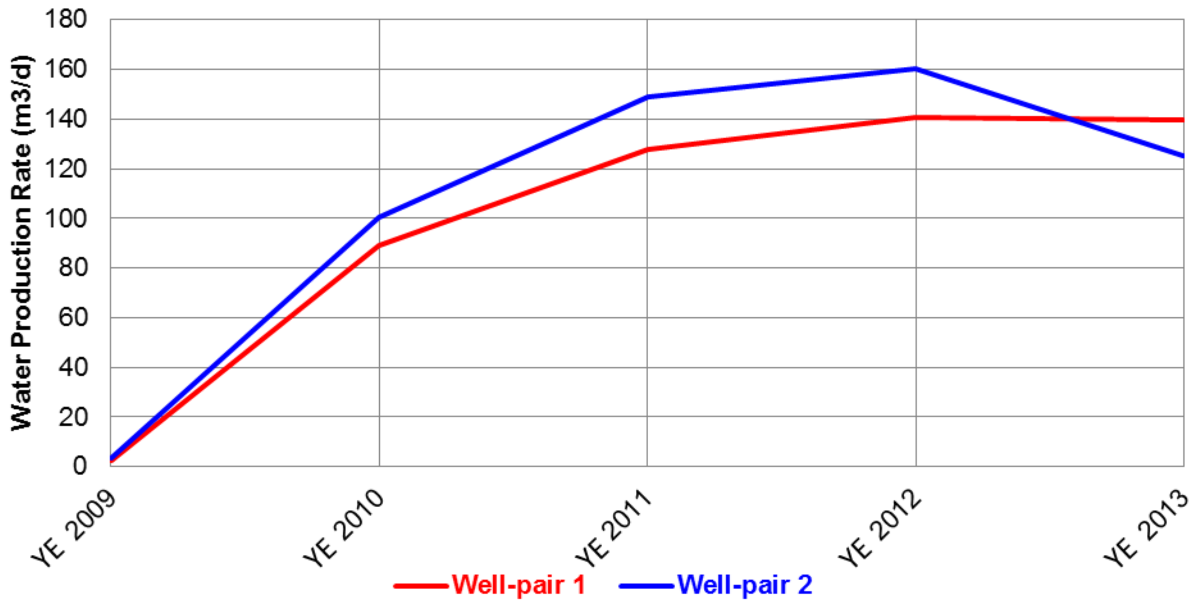
During SAGD / SA-SAGD operation, injection rates are dictated by an operational strategy to maintain injection pressure close to initial reservoir pressure (see section 4.4). Rates typically varied to achieve this, with durations of higher than average injection rates that followed periods of injection shut in (allowing pressure target to be reached in a timely manner). A plot of the yearly average steam injection rates for each well is shown below. [Tables of monthly injection and production history are included in Appendix A].



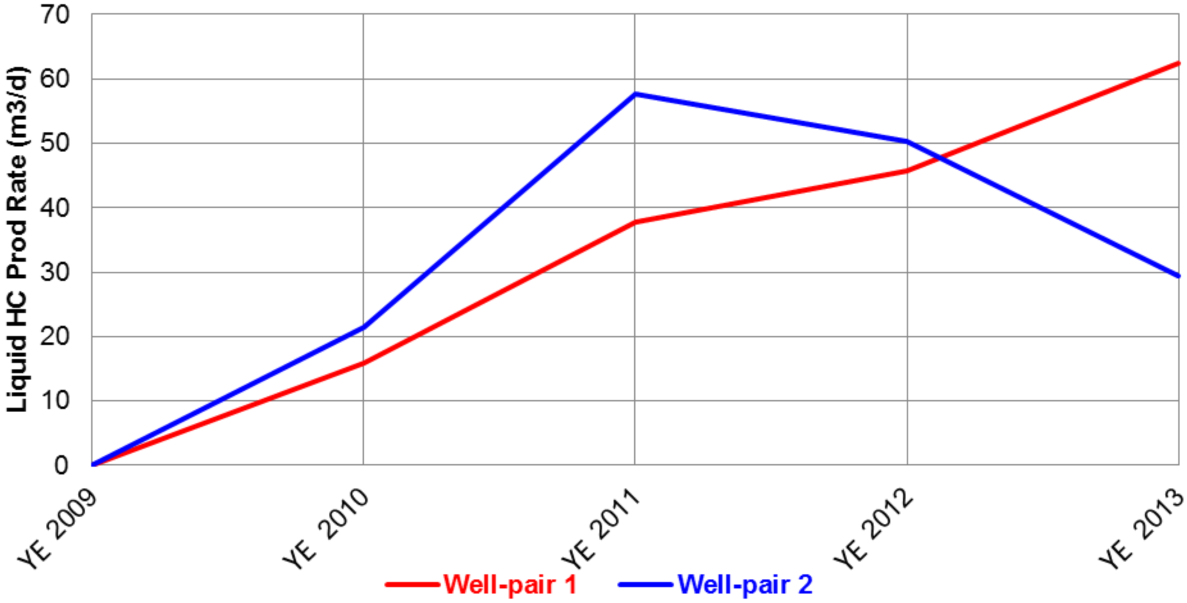
Well-pair 2 operated in SA-SAGD mode until end of May 2012, when well-pair 1 started operating in SA-SAGD mode. Diluent injection rates were dictated by a target diluent volume of roughly 20% of steam volume. A plot of the yearly average diluent injection rates for each well is shown below.



Water production consisted of water from the condensing steam. Water production volumes from each well (yearly average rates) are shown below.

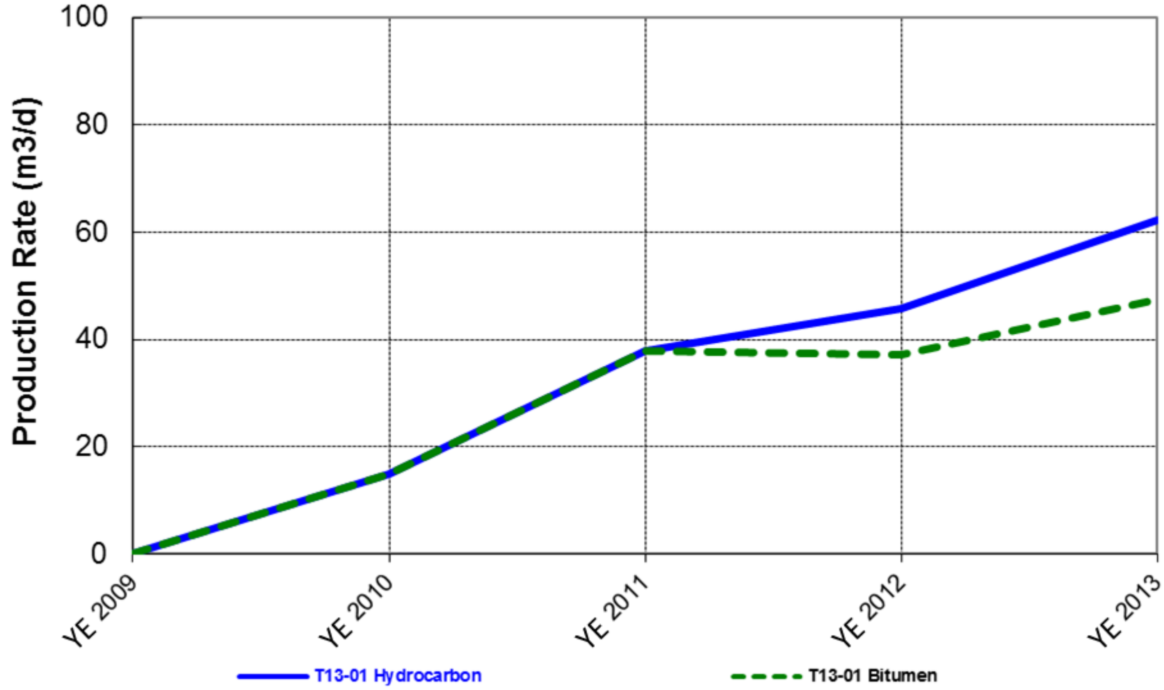


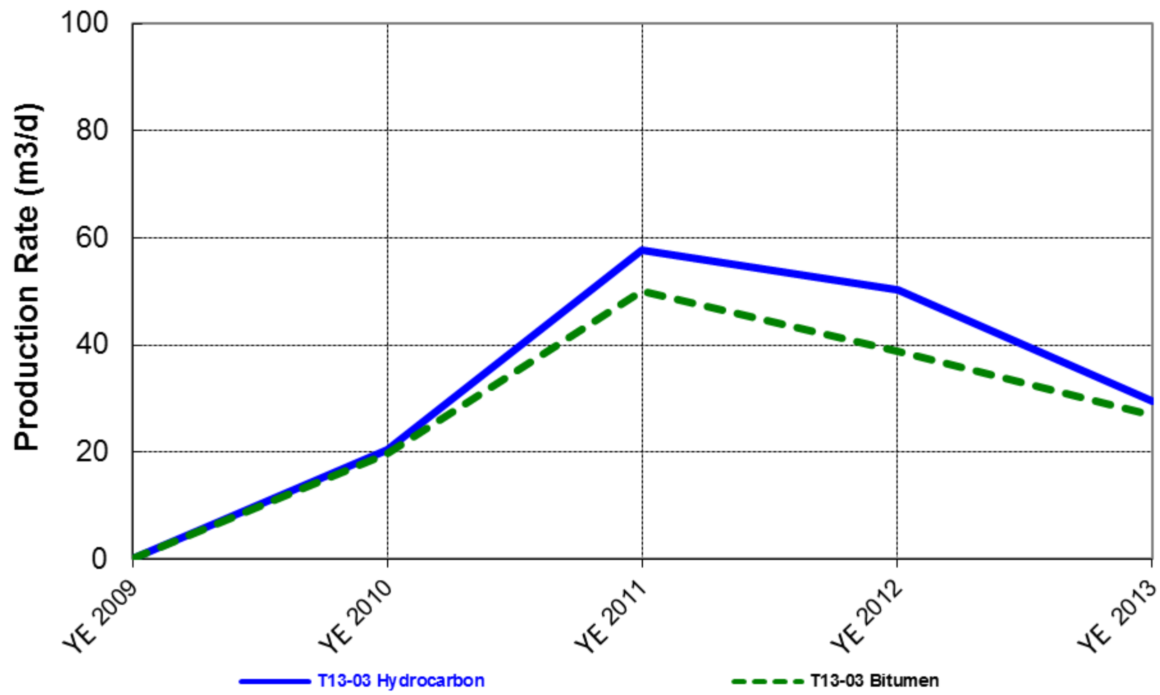
Liquid hydrocarbon volumes consisted of bitumen plus recovered diluent mix. Liquid hydrocarbon production volumes from each well (yearly average rates) are shown below (including liquid hydrocarbon from both the liquid and vent gas separators).



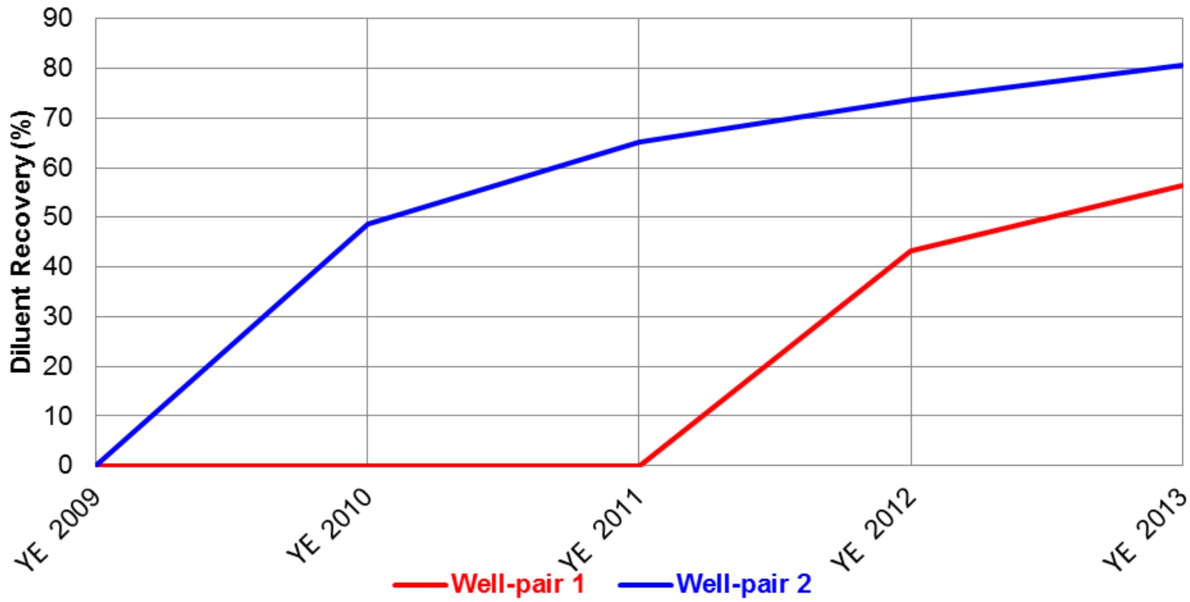
The liquid HC rate plot above shows that yearly average rates are higher for well on SA-SAGD mode (Well-pair 2 from end of 2010 to mid-2012, then well-pair 1 from mid-2012 to current), which is consistent with predictions.

Diluent recovery has also been measured after diluent injection commenced for each well pair. The following plots show hydrocarbon (bitumen and diluent) and bitumen only yearly average production rates.





It was observed that by end of 2013, cumulative diluent recovery had reached 56% for well-pair 1, and 81% for well-pair 2, as shown in plot below.



4.2 Composition of produced / injected fluids

The components of the injected fluid consisted of dry steam and diluent. Injected diluent was originally sourced from Provident Midstream from its facility in Redwater, AB up until June 2013, after which the injected diluent is sourced in Fort Saskatchewan, AB. The tables below detail a typical composition of the diluent in Redwater, AB and in Fort Saskatchewan, AB.

Redwater, AB:

COMPONENT	CARBON NUMBER	MOLE FRACTION	MASS FRACTION	LIQUID VOL FRACTION
Methane	C1	0.0000	0.0000	0.0000
Ethane	C2	0.0000	0.0000	0.0000
Propane	C3	0.0009	0.0005	0.0006
i-Butane	i-C4	0.0012	0.0009	0.0010
n-Butane	n-C4	0.0257	0.0187	0.0212
i-Pentane	i-C5	0.2599	0.2344	0.2489
n-Pentane	n-C5	0.2724	0.2457	0.2586
Hexanes	C6	0.1917	0.2065	0.2065
Heptanes	C7	0.0674	0.0844	0.0815
Octanes	C8	0.0274	0.0391	0.0368
Nonanes	C9	0.0073	0.0117	0.0108
Decanes	C10	0.0028	0.0050	0.0045
Undecanes	C11	0.0009	0.0017	0.0014
Dodecanes	C12	0.0003	0.0007	0.0005
Tridecanes	C13	Trace	Trace	Trace
Tetradecanes	C14	0.0000	0.0000	0.0000
Pentadecanes	C15	0.0000	0.0000	0.0000
Hexadecanes	C16	0.0000	0.0000	0.0000
Heptadecanes	C17	0.0000	0.0000	0.0000
Octadecanes	C18	0.0000	0.0000	0.0000
Nonadecanes	C19	0.0000	0.0000	0.0000
Eicosanes	C20	0.0000	0.0000	0.0000
Heneicosanes	C21	0.0000	0.0000	0.0000
Docosanes	C22	0.0000	0.0000	0.0000
Tricosanes	C23	0.0000	0.0000	0.0000
Tetracosanes	C24	0.0000	0.0000	0.0000
Pentacosanes	C25	0.0000	0.0000	0.0000
Hexacosanes	C26	0.0000	0.0000	0.0000
Heptacosanes	C27	0.0000	0.0000	0.0000
Octacosanes	C28	0.0000	0.0000	0.0000
Nonacosanes	C29	0.0000	0.0000	0.0000
Triacontanes Plus	C30 +	0.0000	0.0000	0.0000
Benzene	C6H6	0.0097	0.0095	0.0071
Toluene	C7H8	0.0095	0.0110	0.0083
Ethylbenzene, p + m-Xylene	C8H10	0.0057	0.0075	0.0058
o-Xylene	C8H10	0.0013	0.0017	0.0013
1, 2, 4 Trimethylbenzene	C9H12	0.0003	0.0004	0.0003
Cyclopentane	C5H10	0.0310	0.0272	0.0241
Methylcyclopentane	C6H12	0.0362	0.0381	0.0336
Cyclohexane	C6H12	0.0231	0.0243	0.0206
Methylcyclohexane	C7H14	0.0253	0.0310	0.0266
TOTAL		**1**	**1**	**1**

Fort Saskatchewan, AB:

COMPONENT	CARBON NUMBER	MOLE FRACTION	MASS FRACTION	LIQUID VOL FRACTION
Methane	C1	0.0000	0.0000	0.0000
Ethane	C2	0.0000	0.0000	0.0000
Propane	C3	Trace	Trace	Trace
i-Butane	i-C4	0.0001	0.0001	0.0001
n-Butane	n-C4	0.0109	0.0080	0.0091
i-Pentane	i-C5	0.2907	0.2650	0.2813
n-Pentane	n-C5	0.2814	0.2567	0.2699
Hexanes	C6	0.1603	0.1746	0.1744
Heptanes	C7	0.0682	0.0864	0.0833
Octanes	C8	0.0180	0.0260	0.0244
Nonanes	C9	0.0036	0.0059	0.0054
Decanes	C10	0.0015	0.0027	0.0024
Undecanes	C11	0.0008	0.0015	0.0012
Dodecanes	C12	0.0005	0.0011	0.0008
Tridecanes	C13	0.0004	0.0008	0.0007
Tetradecanes	C14	0.0002	0.0006	0.0004
Pentadecanes	C15	0.0002	0.0004	0.0004
Hexadecanes	C16	0.0001	0.0004	0.0002
Heptadecanes	C17	Trace	Trace	Trace
Octadecanes	C18	Trace	Trace	Trace
Nonadecanes	C19	0.0000	0.0000	0.0000
Eicosanes	C20	0.0000	0.0000	0.0000
Heneicosanes	C21	0.0000	0.0000	0.0000
Docosanes	C22	0.0000	0.0000	0.0000
Tricosanes	C23	0.0000	0.0000	0.0000
Tetracosanes	C24	0.0000	0.0000	0.0000
Pentacosanes	C25	0.0000	0.0000	0.0000
Hexacosanes	C26	0.0000	0.0000	0.0000
Heptacosanes	C27	0.0000	0.0000	0.0000
Octacosanes	C28	0.0000	0.0000	0.0000
Nonacosanes	C29	0.0000	0.0000	0.0000
Triacontanes Plus	C30 +	0.0000	0.0000	0.0000
Benzene	C6H6	0.0098	0.0097	0.0073
Toluene	C7H8	0.0054	0.0063	0.0048
Ethylbenzene, p + m-Xylene	C8H10	0.0020	0.0027	0.0021
o-Xylene	C8H10	0.0004	0.0006	0.0004
1, 2, 4 Trimethylbenzene	C9H12	0.0001	0.0002	0.0001
Cyclopentane	C5H10	0.0424	0.0376	0.0333
Methylcyclopentane	C6H12	0.0649	0.0690	0.0608
Cyclohexane	C6H12	0.0201	0.0214	0.0181
Methylcyclohexane	C7H14	0.0180	0.0223	0.0191
TOTAL		**1**	**1**	**1**

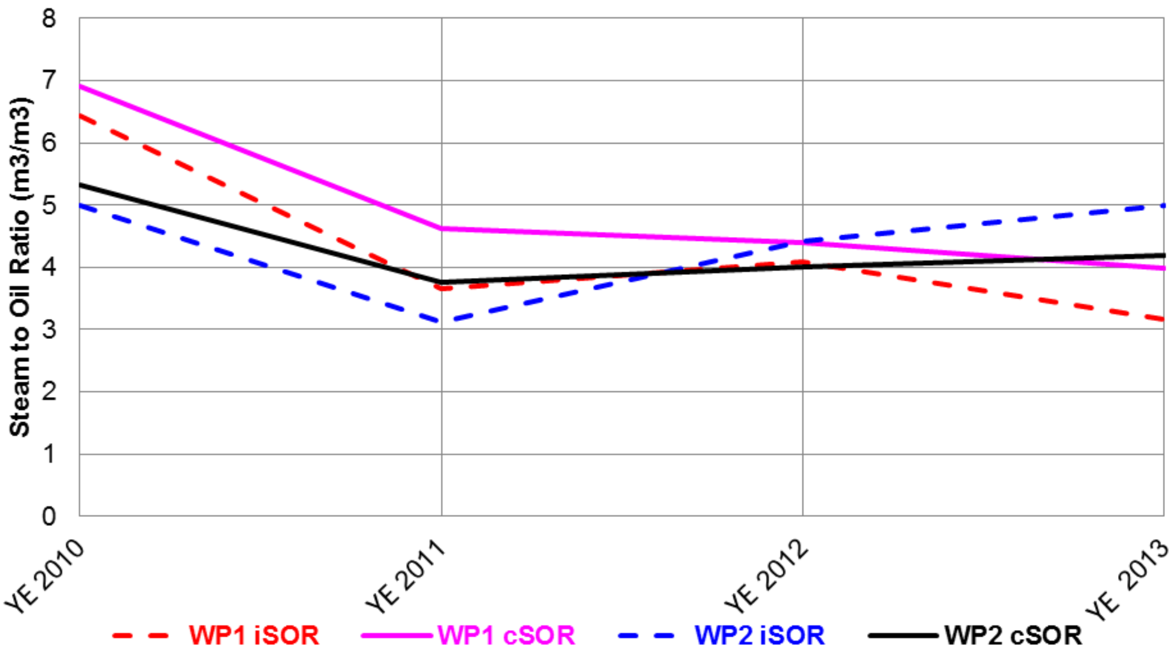
Produced fluids consisted of condensed water, bitumen, and recovered solvent. The table below details a typical composition of Cold Lake bitumen.

COMPONENT	CARBON NUMBER	MOLE FRACTION	MASS FRACTION	LIQUID VOL FRACTION
Methane	C1	0.0000	0.0000	0.0000
Ethane	C2	0.0000	0.0000	0.0000
Propane	C3	0.0000	0.0000	0.0000
i-Butane	i-C4	0.0000	0.0000	0.0000
n-Butane	n-C4	0.0000	0.0000	0.0000
i-Pentane	i-C5	0.0000	0.0000	0.0000
n-Pentane	n-C5	0.0000	0.0000	0.0000
Hexanes	C6	0.0000	0.0000	0.0000
Heptanes	C7	0.0000	0.0000	0.0000
Octanes	C8	Trace	Trace	Trace
Nonanes	C9	Trace	Trace	Trace
Decanes	C10	0.0025	0.0006	0.0007
Undecanes	C11	0.0084	0.0022	0.0024
Dodecanes	C12	0.0174	0.0050	0.0054
Tridecanes	C13	0.0290	0.0090	0.0096
Tetradecanes	C14	0.0344	0.0115	0.0122
Pentadecanes	C15	0.0411	0.0147	0.0155
Hexadecanes	C16	0.0425	0.0162	0.0169
Heptadecanes	C17	0.0425	0.0172	0.0179
Octadecanes	C18	0.0404	0.0173	0.0179
Nonadecanes	C19	0.0391	0.0177	0.0182
Eicosanes	C20	0.0368	0.0175	0.0180
Heneicosanes	C21	0.0366	0.0183	0.0187
Docosanes	C22	0.0313	0.0164	0.0167
Tricosanes	C23	0.0296	0.0162	0.0164
Tetracosanes	C24	0.0261	0.0149	0.0150
Pentacosanes	C25	0.0246	0.0146	0.0147
Hexacosanes	C26	0.0243	0.0150	0.0150
Heptacosanes	C27	0.0225	0.0144	0.0144
Octacosanes	C28	0.0217	0.0144	0.0144
Nonacosanes	C29	0.0218	0.0150	0.0149
Triacontanes Plus	C30 +	0.4274	0.7319	0.7251
Benzene	C6H6	0.0000	0.0000	0.0000
Toluene	C7H8	0.0000	0.0000	0.0000
Ethylbenzene, p + m-Xylene	C8H10	0.0000	0.0000	0.0000
o-Xylene	C8H10	0.0000	0.0000	0.0000
1, 2, 4 Trimethylbenzene	C9H12	0.0000	0.0000	0.0000
Cyclopentane	C5H10	0.0000	0.0000	0.0000
Methylcyclopentane	C6H12	0.0000	0.0000	0.0000
Cyclohexane	C6H12	0.0000	0.0000	0.0000
Methylcyclohexane	C7H14	0.0000	0.0000	0.0000
TOTAL		**1.0000**	**1.0000**	**1.0000**

4.3 Predicted vs. Actual Comparisons

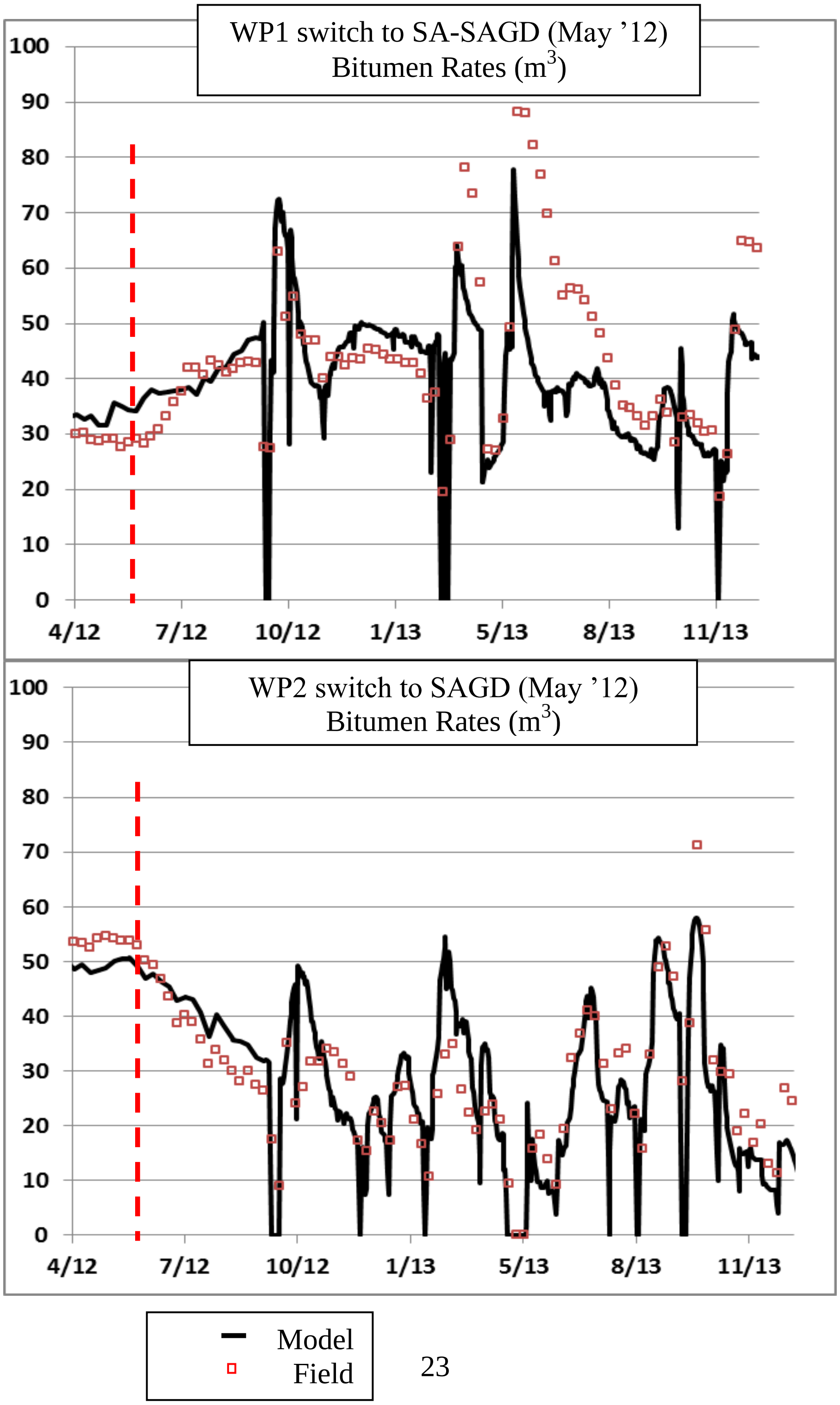
Well-pair 1 cumulative Steam Oil Ratio (cSOR) was high initially; a yearly average of around 7 for 2010, the reason is that in the early phase, large volumes of steam were injected for start-up/warmup, with little oil produced. The cSOR then dropped to an average of 4.6 for 2011. After switching well-pair 1 from SAGD to SA-SAGD, SOR dropped further, and reached an average of 4 by end of 2013.

Well-pair 2 cSOR was also high initially, and dropped to under 4 by end of 2011. Solvent injection into this pair contributed to the relatively lower SORs. After switching to SAGD, SOR started to slowly increase, as expected, as the impact of adding solvent was diminishing.

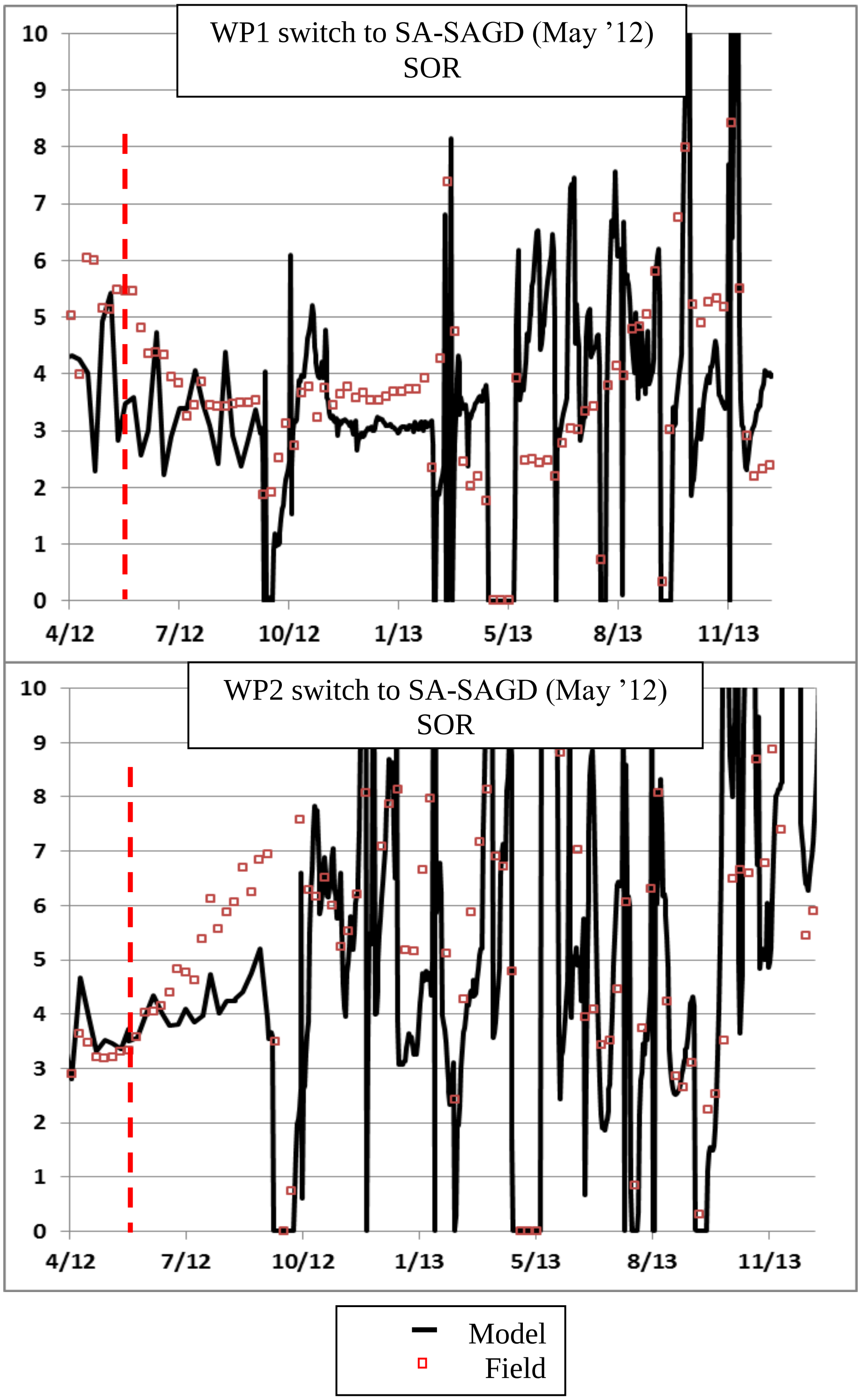


Field data was also used to history match a geologic-model based simulation model for SAGD / SA-SAGD operation, and create go forward predictions. The model was updated to better handle skin development observed in the field; model inputs were changed from production pressures to total liquid rates, individual fluid volumes were matched and difference in pressure was attributed to skin (implicit method of modeling skin).

The plots below show a comparison of field data with latest history matched simulation model results, focused on the impact of solvent on SAGD performance (i.e. period of solvent switch). [Dashed red line marks the time of the solvent switch].

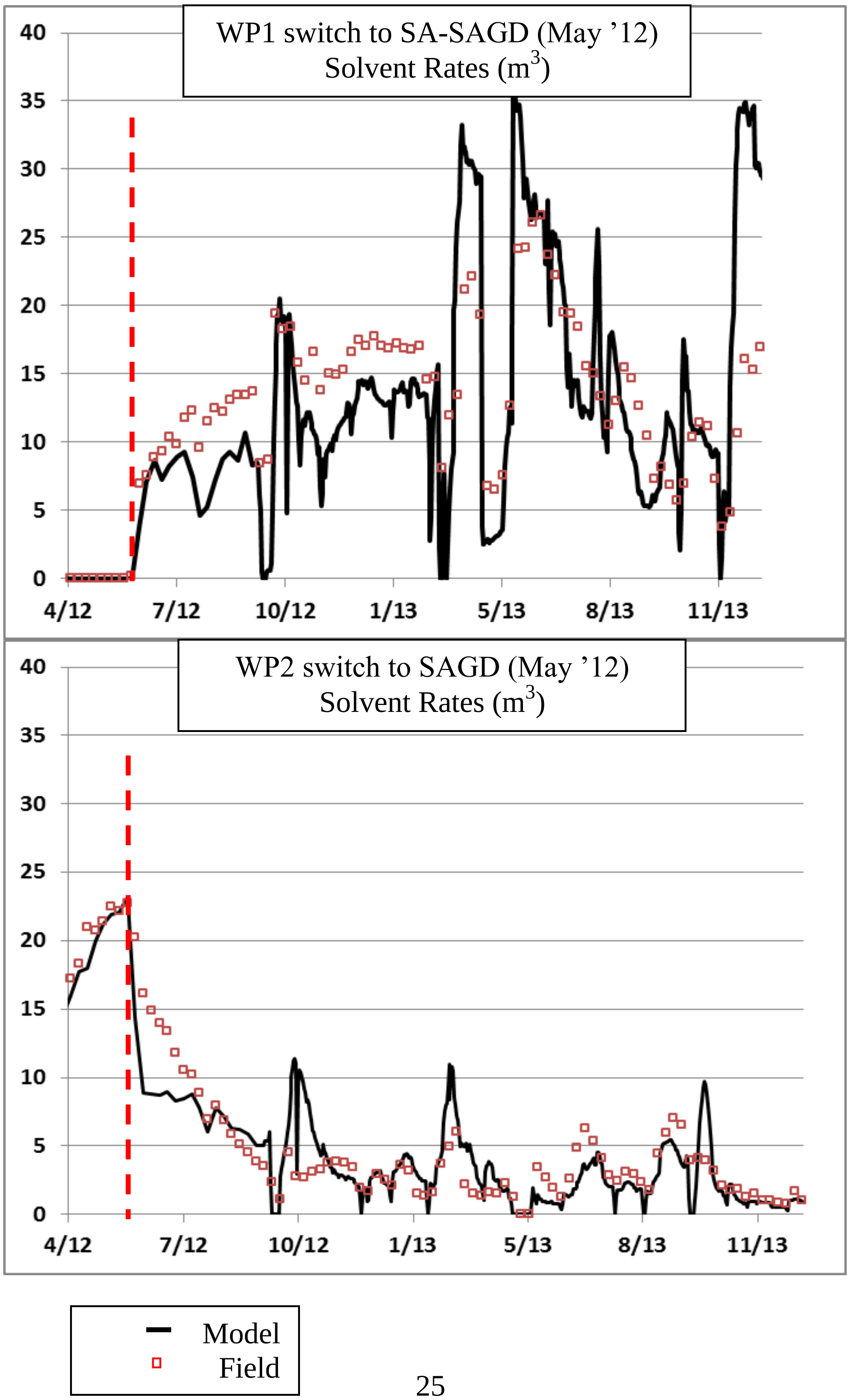


The plots above show that the model clearly captures impact of solvent injection on SAGD performance; increase in WP1 after starting solvent injection, and a decrease in WP2 after stopping solvent injection. The following plots show impact of solvent on SOR:

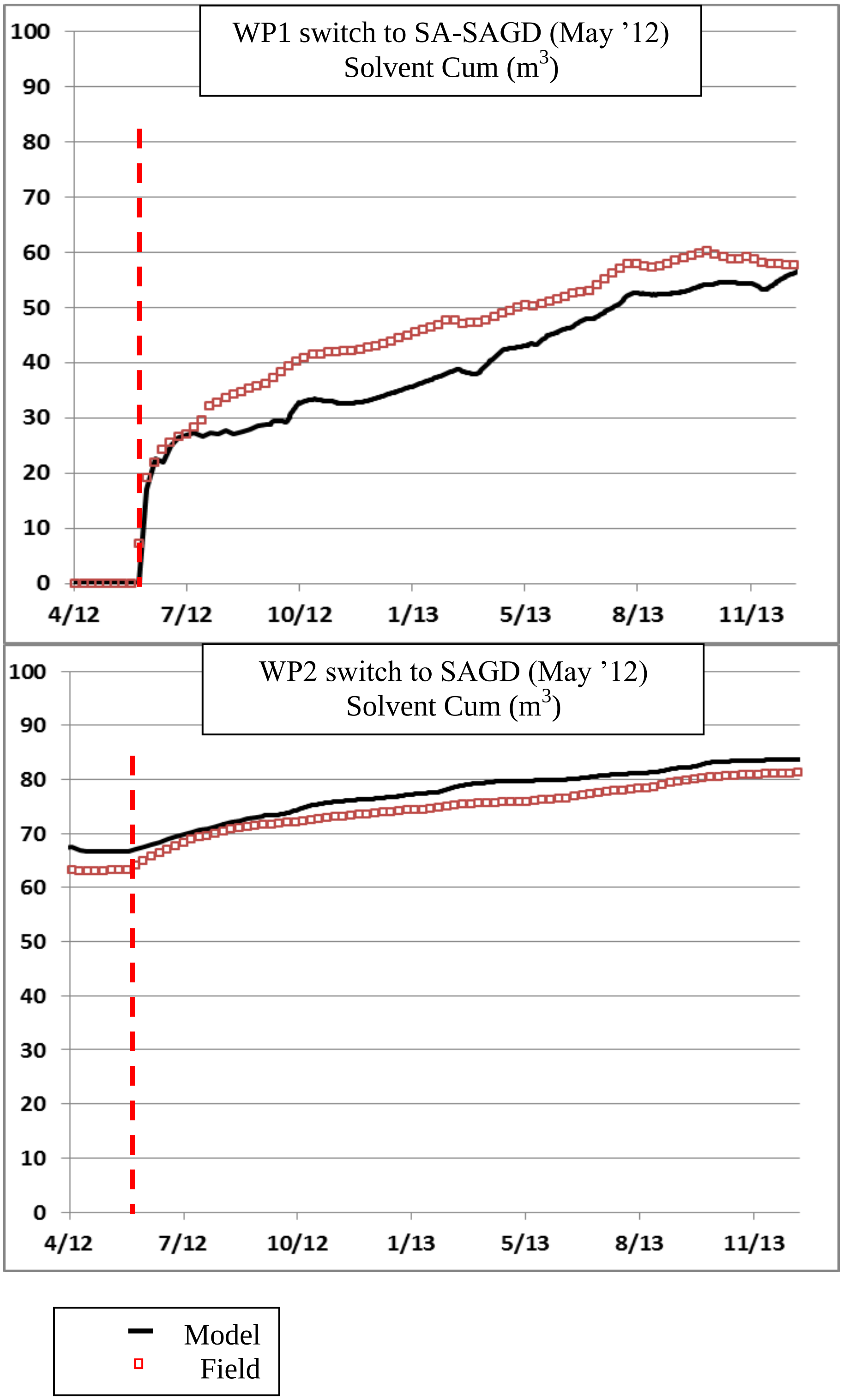


SOR plots above illustrate model's ability to capture the decrease in SOR upon solvent injection at WP1, and increase in SOR upon stopping solvent injection at WP2. Note that the large oscillations in bitumen production rates and SOR from late 2012 onwards are due to skin development issues and well interventions.

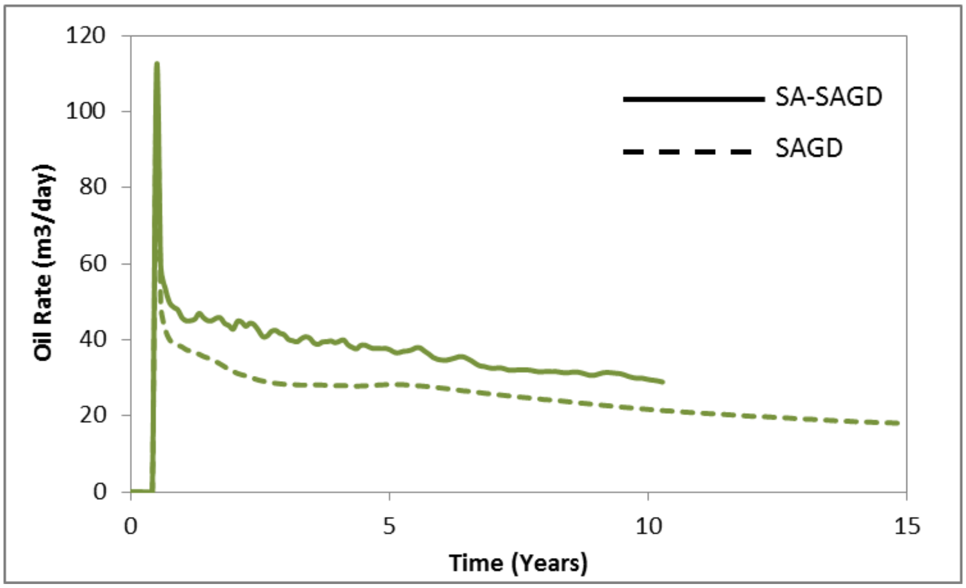
The plots below show the latest model's match to field solvent production rates, which is considered to be a reasonable match.

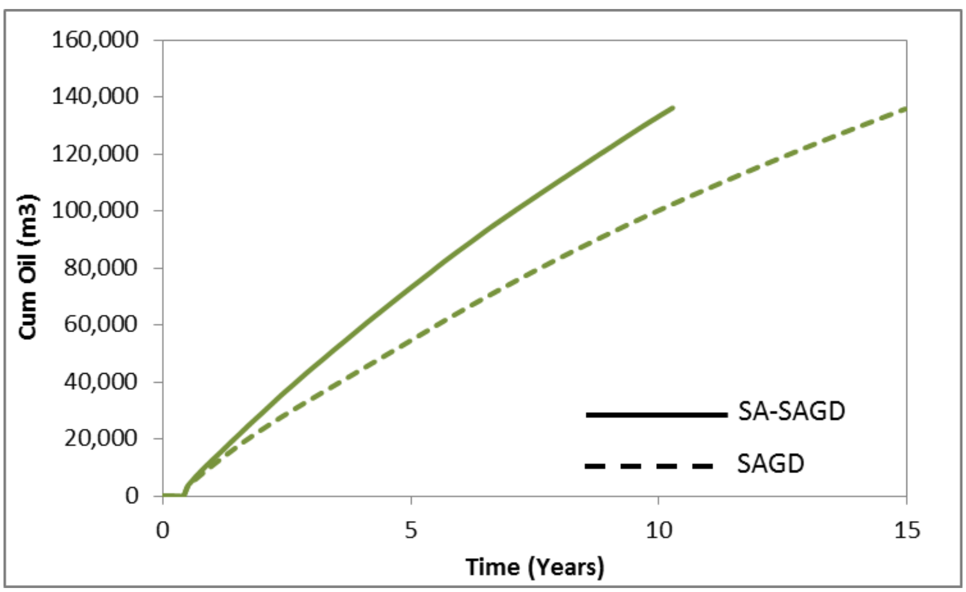


The following plots show the model's match to field cumulative solvent volumes, which is also deemed to be an acceptable match. It was discovered that solvent recovery is very sensitive to initial water saturation in the model, and adjusting that input could seemingly 'improve' the match, however, the team decided to use realistic initial water saturation inputs and to keep saturation values consistent between the well-pairs.

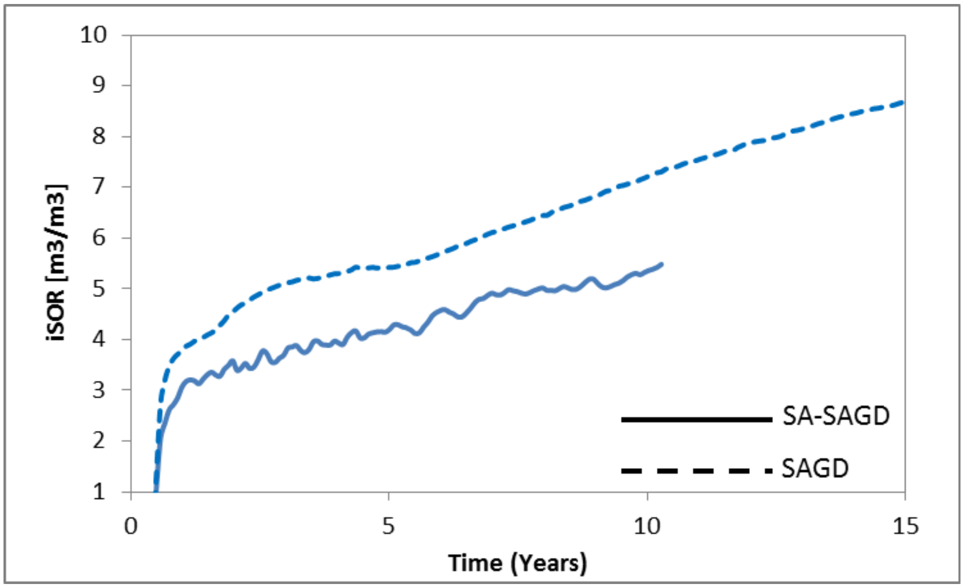


The plots below show SAGD and SA-SAGD model predictions, which are generated using the T13 history matched model. The predictions are run on a constant injection pressure and constant allowable live steam production rate for both cases. For the SA-SAGD case, solvent injection is kept constant at 20% vol solvent/vol steam. To show improvement of SA-SAGD over SAGD, both cases were cut off after producing roughly the same cumulative oil volume, after 15 years of SAGD. There's clearly an oil rate uplift associated with the SA-SAGD process. The initial spike in oil rate is a result of the way the heating period is modeled (simulator artifact), the extended heating period causes oil to accumulate until it is ready to be produced, which causes the spike in rates.



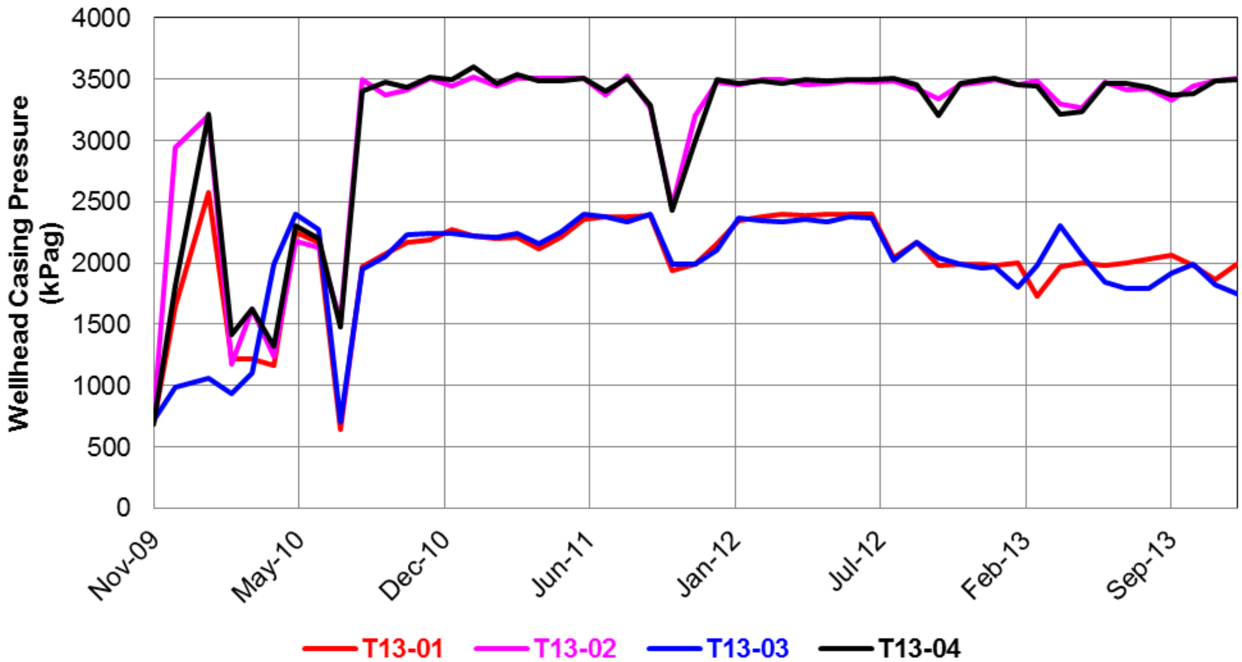


Instantaneous SOR plot below show the magnitude of reduction of SOR associated with using solvent compared to SAGD.



4.4 Pressures

During SAGD operation, steam is injected close to reservoir pressure (wellhead pressure of 3,500 kPa) in wells T13-02 and T13-04, with wellhead production in the 1,700-2,300 kPa range (wells T13-01 and T13-03). Our team was able to demonstrate the capability of running a SAGD/SA-SAGD operation with constant injection pressures. Plots of casing wellhead pressures (monthly average) for each well are shown below.

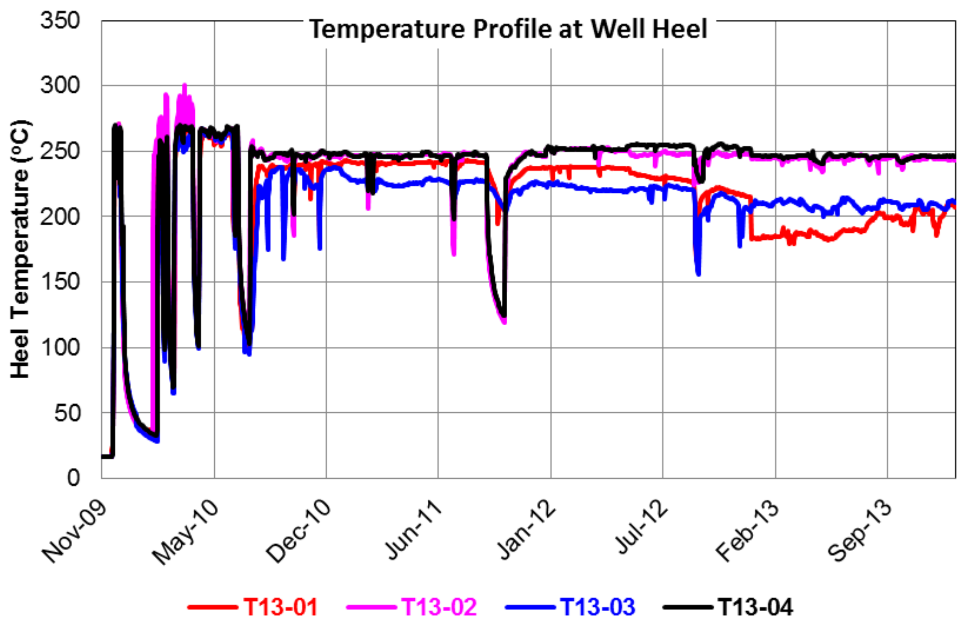


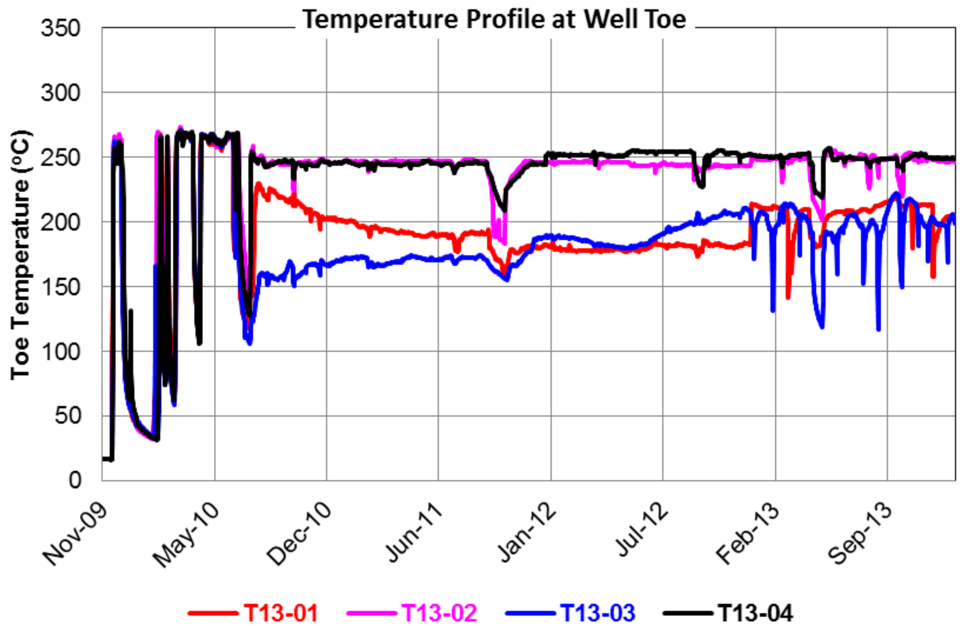
5 Pilot Data

5.1 Additional data

Beyond pressure and production, additional surveillance data collected during this time included temperature in each horizontal well and all six observation wells.

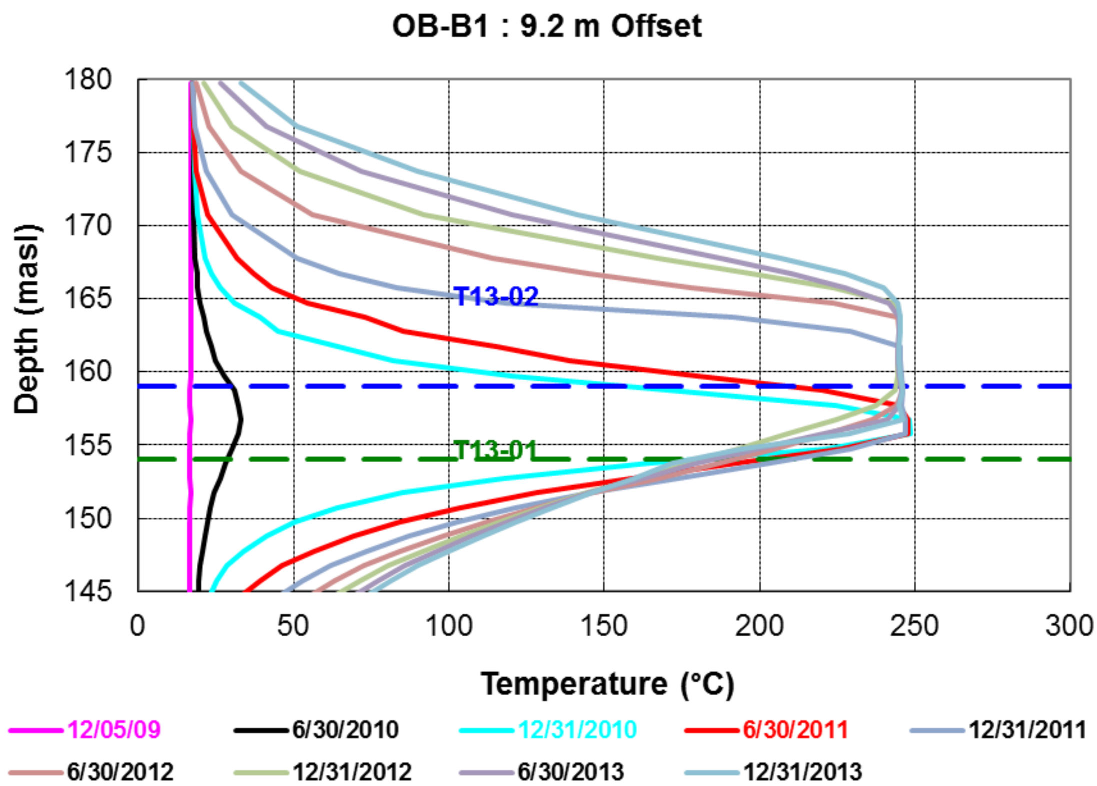
Injector well temperatures were approximately 250°C during SAGD/SA-SAGD operation (heel and toe of T13-02 & T13-04). Temperatures on the producer wells (T13-01 & T13-03) varied from 155-245°C along the wells during SAGD/SA-SAGD operation. Temperatures (daily average) along the horizontal well at the heel and toe are shown below.

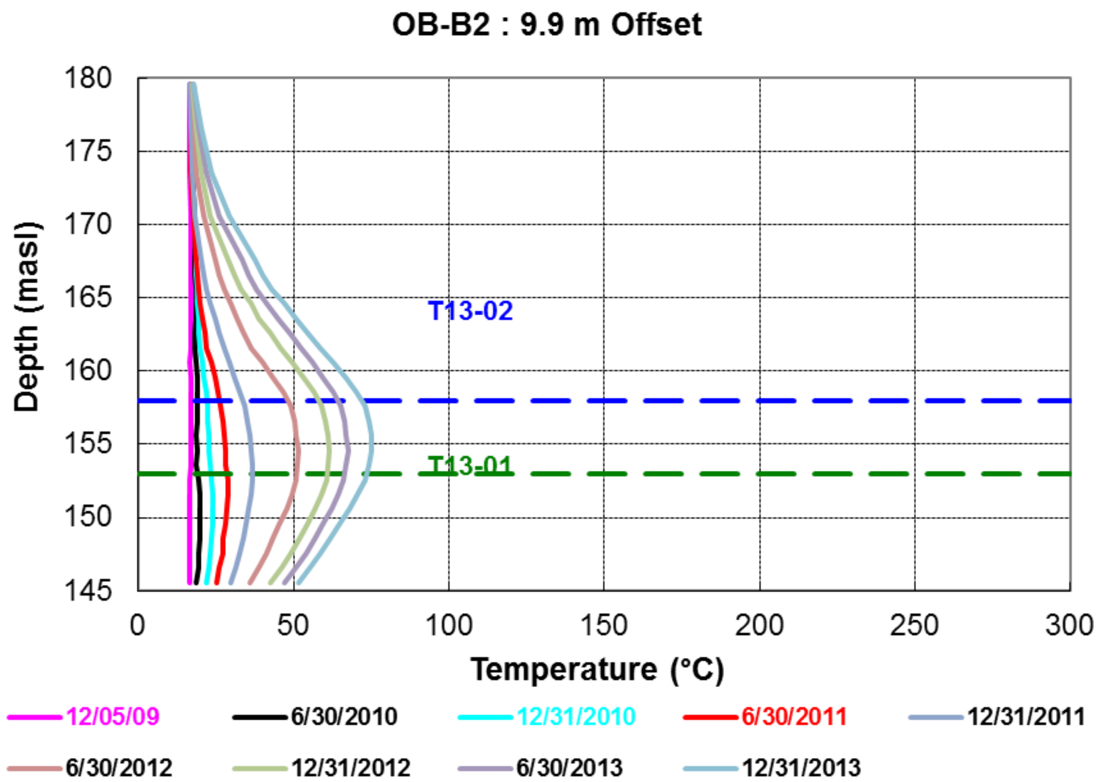


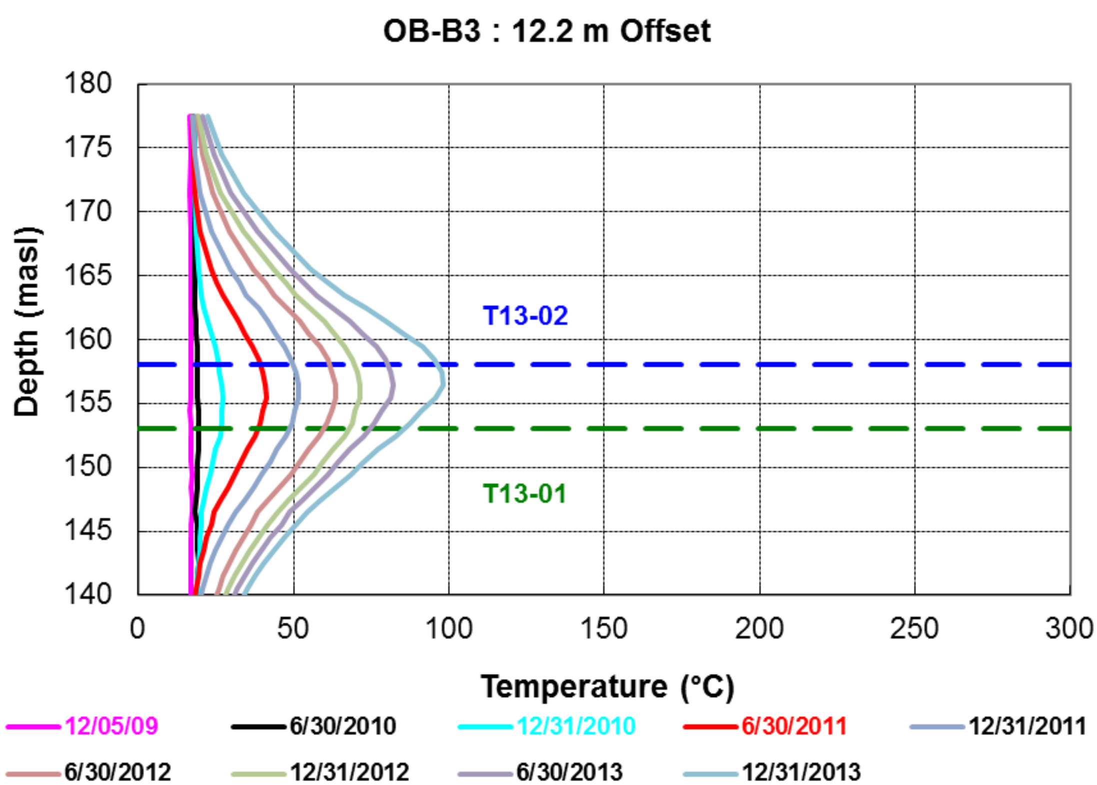


There are six total observation wells, three for each well-pair, that are positioned at the toe, heel, and midpoint of each horizontal well-pair. The offset distance from the horizontal wells varies between 5.7 and 13.5 m. The temperature at the observation wells provides a measure of the amount of heat transferred to the reservoir.

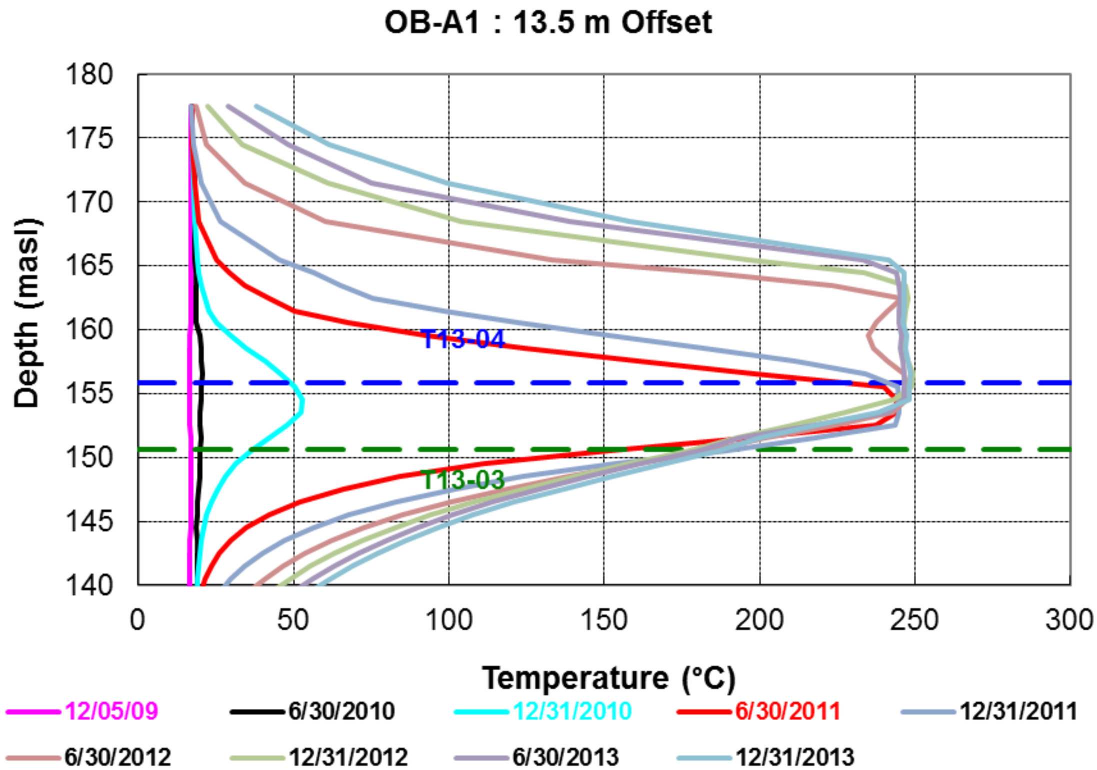
Observation wells OB-B1, B2, and B3 are adjacent to heel, mid, and toe of well-pair 1 (T13-01 & T13-02). Steam temperature was reached on OB-B1 at the end of 2010, with continued vertical growth observed in 2011-2013. Temperature responses of between 75-100°C were also observed on B2 & B3 by the end of 2013. The temperature as a function of depth is shown below for each observation well at six-month intervals (dashed lines represent approximate depths of both the injector and producer wells from the adjacent well-pair).

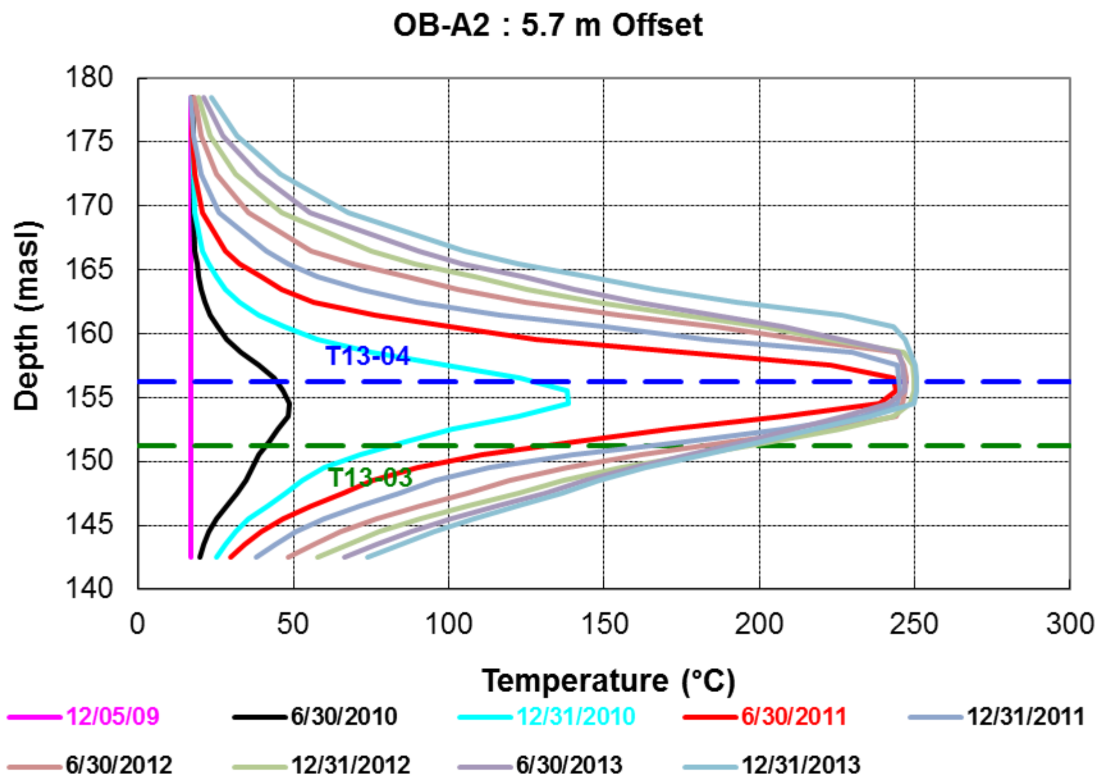


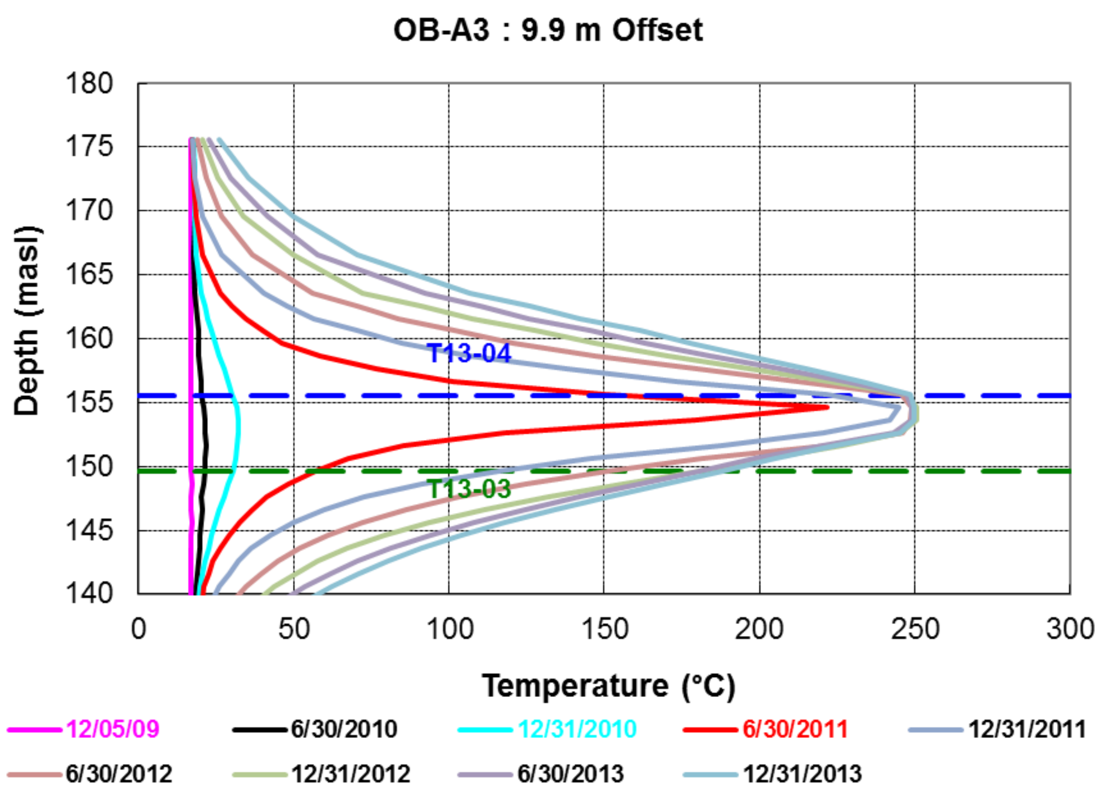

OB-B2 : 9.9 m Offset
180
175
170
165
160
155
150
145
Depth (masl)
0
50
100
150
200
250
300
Temperature (°C)
T13-02
T13-01
12/05/09
6/30/2010
12/31/2010
6/30/2011
12/31/2011
6/30/2012
12/31/2012
6/30/2013
12/31/2013


OB-B3 : 12.2 m Offset
180
175
170
165
160
155
150
145
140
Depth (masl)
0
50
100
150
200
250
300
Temperature (°C)
T13-02
T13-01
12/05/09
6/30/2010
12/31/2010
6/30/2011
12/31/2011
6/30/2012
12/31/2012
6/30/2013
12/31/2013

Observation wells OB-A1, A2, and A3 are adjacent to heel, mid, and toe of well-pair 2 (T13-03 & T13-04). All three wells reached steam temperature in 2011, and chamber continued vertical growth through 2013. The temperature as a function of depth is shown below for each observation well at six-month intervals (dashed lines represent approximate depths of both the injector and producer wells from the adjacent well-pair).

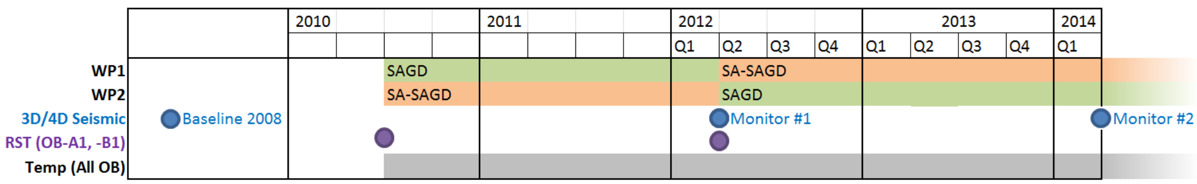



OB-A2 : 5.7 m Offset
180
175
170
165
160
155
150
145
140
Depth (masl)
0
50
100
150
200
250
300
Temperature (°C)
T13-04
T13-03
12/05/09
6/30/2010
12/31/2010
6/30/2011
12/31/2011
6/30/2012
12/31/2012
6/30/2013
12/31/2013


OB-A3 : 9.9 m Offset
180
175
170
165
160
155
150
145
140
Depth (masl)
0
50
100
150
200
250
300
Temperature (°C)
T13-04
T13-03
12/05/09
6/30/2010
12/31/2010
6/30/2011
12/31/2011
6/30/2012
12/31/2012
6/30/2013
12/31/2013

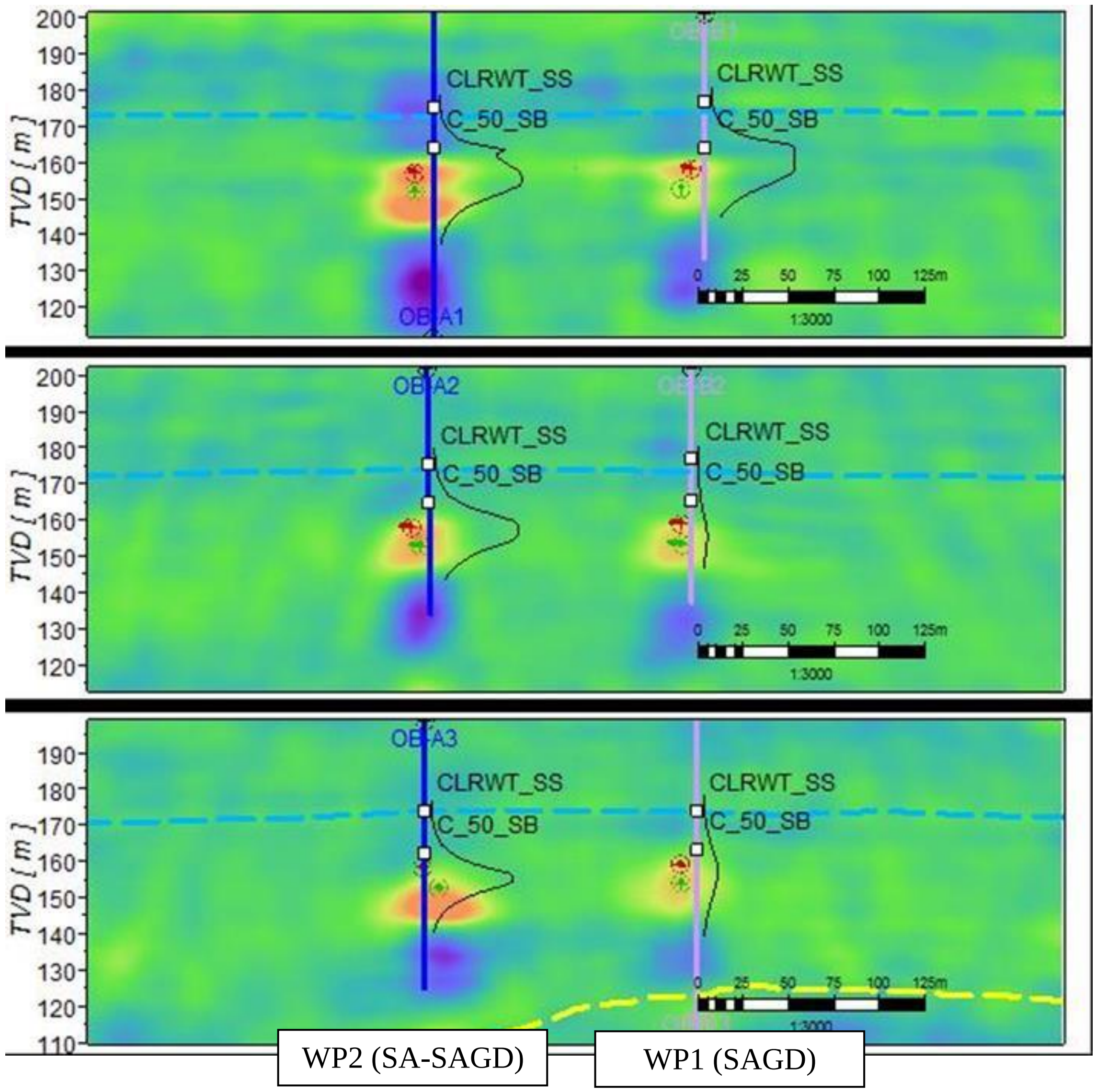
5.2 Interpretation of pilot data

A total of three seismic surveys were acquired at T13 – 2008 (baseline), 2012 (4D monitor #1), and 2014 (4D monitor #2), as shown in the timeline below. The timing of the monitor surveys was scheduled to align with solvent mode crossovers in the T13 well-pairs. This section focuses on the changes observed between the 2012 and 2014 surveys.



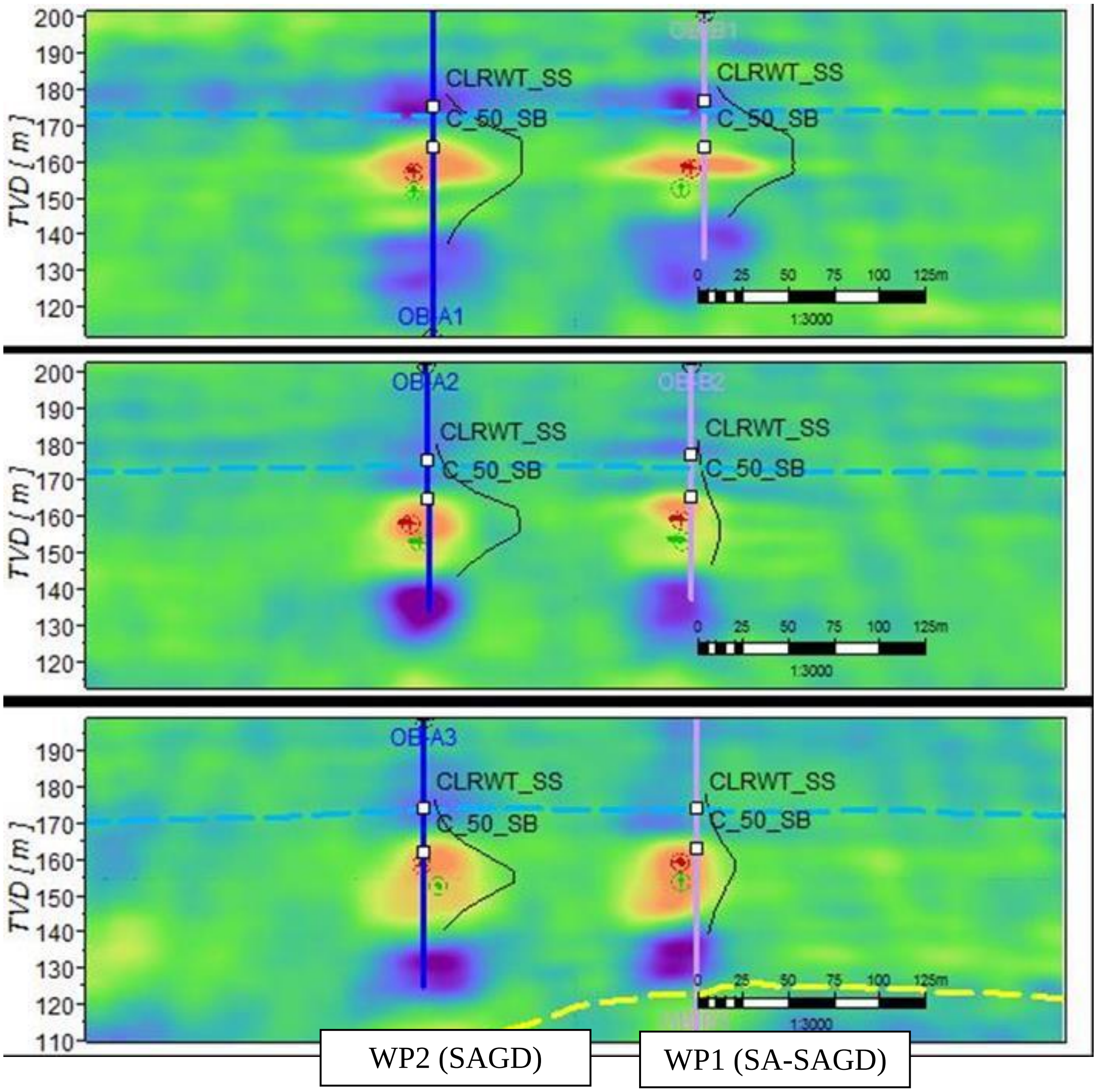
Shown below is the 2012 4D impedance difference (monitor #1 - baseline) calculated after 4D cross-equalization, inversion, and depth conversion. Overlain on the OB well trajectory is the thermocouple temperature profile at the time of seismic acquisition The SAGD/SA-SAGD well-pairs intersect the cross section plane and are indicated by circled crosses. Hot colors represent decreases in acoustic impedance relative to the baseline survey, and indicate the steam chamber or gas exsolution zone.

2012 Seismic Monitor Survey



Shown below is the 2014 impedance difference (monitor #2 – monitor #1). The primary finding of the 2014 monitor survey relates to the difference in anomaly strength and volume of the SA-SAGD vs. SAGD mode wellpairs, especially temporal variations in chamber growth rates that appear related to solvent injection. Significant seismic anomalies were observed along both well-pairs in the 2012 survey, however the anomaly along wellpair 2 (SA-SAGD mode) is significantly stronger. At the time of the 2014 seismic acquisition, while the strength of the anomalies along both wellpairs had increased, the anomaly along wellpair 1 (now operating in SA-SAGD mode) had increased significantly, with the well-pair 1 anomaly now exceeding the size of the anomaly along wellpair 2 (SAGD) in both amplitude and lateral/vertical extent. See the first figure below for the relative timing of seismic acquisition and solvent injection mode crossovers. These anomalies are seen clearly in both along- and cross-wellbore seismic sections, as well as being clearly apparent in seismic geobody extractions designed to isolate significant decreases in acoustic impedance from baseline to monitor.

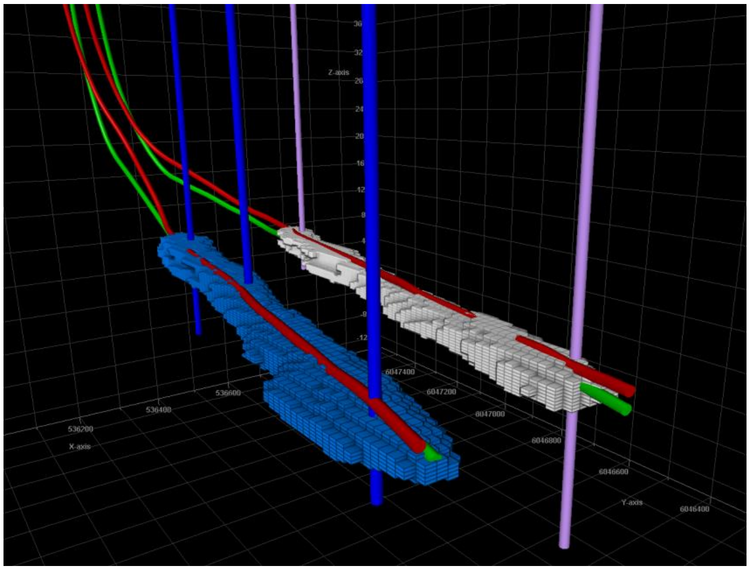
2014 Seismic Monitor Survey



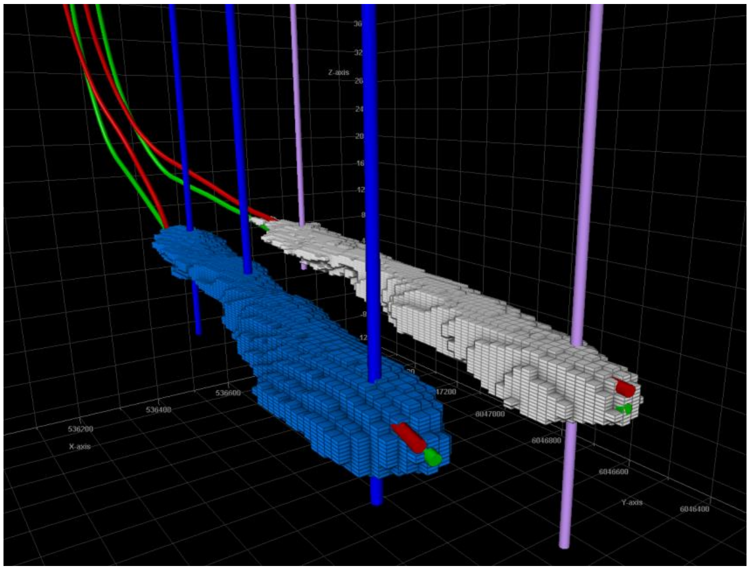
These observations indicate that operation in SA-SAGD mode results in a significant increase in the strength and volume of the observed seismic anomaly, relative to SAGD operation alone. This supports the conclusion that SA-SAGD operation provides an uplift in terms of sweep efficiency relative to SAGD, which is consistent with an increase in production volumes observed during SA-SAGD operation.

The geobodies below are extracted from seismically-derived impedance difference volumes, using a cut-off that retains voxels showing a strong decrease in impedance between the baseline and monitor surveys. The cut off is targeted at the impedance decrease expected for Clearwater reservoir containing greater than 3 – 5% vapour saturation.

2012 Low Impedance Geobodies



2014 Low Impedance Geobodies



6 Pilot Economics

Price data used in this section is a combination of:

- Bitumen/natural gas pricing based on actual prices from Imperial Oil's 10-K filing
- Solvent pricing from the Sproule price database

	Bitumen C$/bbl	Solvent (Edmonton Pentanes Plus) C$/bbl	Natural Gas C$/kcf
2009	51.81	68.13	4.11
2010	58.36	84.21	4.04
2011	63.95	104.12	3.59
2012	59.76	100.84	2.33
2013	60.57	105.48	3.27

6.1 Sales volumes of natural gas and by-products

Natural gas volumes produced consisted of solution gas. These gas volumes were sent via a production pipeline to Imperial's Mahkeses plant, and used as fuel gas for steam generation. Natural gas production and steam injection is summarized in the table below.

(m3)	Steam Inj.	Diluent Inj.	Water Prod.	Oil Prod.	Diluent Prod.	Gas Prod.
2009	4,843	0	2,101	0	0	0
2010	74,861	1,207	69,341	13,345	601	103,613
2011	107,525	7,974	101,041	32,014	5,457	502,640
2012	118,158	10,728	110,026	27,774	7,305	77,795
2013	103,556	7,487	96,600	27,097	6,430	128,776

Given the above steam injection and natural gas production volumes, as well the 75 m^3 natural gas / m^3 steam ratio to generate steam, the amount of natural gas that was required to generate steam is shown in the table below:

	NG burned (m3)	Net NG (m3)	Net NG (C$)
2009	363,255	-363,255	-52,724
2010	5,614,538	-5,510,925	-786,251
2011	8,064,405	-7,561,765	-958,678
2012	8,861,858	-8,784,063	-722,781
2013	7,766,708	-7,637,932	-882,020

6.2 Revenue

Gross revenue for the pilot from 2010 to 2013 is shown below. This is based on pilot's bitumen production volumes and average bitumen price for years 2010 through 2013.

C$	2010	2011	2012	2013	Total (to YE 2013)
Bitumen Revenue	4,898,707	12,877,231	10,439,665	10,323,285	**38,538,887**
Solvent Revenue	318,082	3,573,606	4,633,493	4,266,111	**12,791,293**
Total Revenue	**5,216,789**	**16,450,837**	**15,073,158**	**14,589,396**	**51,330,180**

6.3 Capital costs

The following table summarizes capital costs by category, incurred from 2010 to 2013:

Category	Description and Details of Capital Costs	Cost (C$)
Facilities	Drilling	52,573.14
	Surface Facilities (Steam injection facilities, separator; chemical injection facilities, separator; production facilities, pump jacks, ROV, coolers)	9,624,694.60
	Engineering Procurement Construction	3,860,626.41
	Trunkline / Laterals	115,928.66
	Facilities - Capital Related Expense	1,197,346.75
Drilling	Drilling four horizontal wells - 2 well pairs, each well-pair consist of an injector and producer well.	5,997,898.02
	Completion of horizontal wells	2,384,336.56
	Capital Related Expense	56,109.54
Trunkline	Drilling	146.62
	Surface Facilities	56,894.61
	Engineering Procurement Construction	101,187.16
	Trunkline / Laterals	2,723,590.41
	Capital Related Expense	34,391.54
Total Capital Costs (C$)		**26,205,724.02**

6.4 Direct and indirect operating costs

The following table summarizes operating costs by category, incurred from 2010 to 2013, plus the cost of the 4D seismic shoot taken in 2014 (included in Surveillance costs):

Category	Description and Details of Operating Costs	Cost (C$)
Facility Exp.	Drilling observation wells, well heads, completions, reservoir monitoring instrumentation	2,428,888.03
	Completions	178,668.75
	Surface Facilities (Facilities portion associated with solvent injection: solvent tank, pump, lines; production and vent gas testing equipment, samples, separators, horizontal well reservoir monitoring instrumentation; EPCM)	10,259,306.12
Field Exp.	Field operating costs	3,848,201.35
	Surveillance costs	2,892,963.37
Total Operating Costs (C$)		**19,608,027.62**

In addition, solvent injectant costs were incurred. These consisted of both cost of solvent, as well as trucking costs associated with transporting these volumes to site. Solvent costs incurred from 2010 to 2013 were:

Total Injectant Costs (C$)	**19,401,319.41**

Lastly, as discussed in the 2009 annual report presentation, steam for the pilot is generated at Imperial Oil's Cold Lake Mahkeses plant, which falls outside of the IETP project scope. As steam generated for the SA-SAGD pilot is a small fraction of the total plant capacity, it is difficult to include steam generation costs in the IETP claim forms that are accurate and auditable. As a result, estimates have been made (see section 6.1 and 6.6) to aid in cash flow calculations.

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. Revenue began to be generated in 2010, with the pilot contributing to total Cold Lake payable royalties over the last four years. Cost of 2014 seismic shoot is included with 2013 SA-SAGD CAPEX & OPEX.

(C$)	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total ('05-'14)
SA-SAGD Revenue[1]	0	0	0	0	0	5,216,789	16,450,837	15,073,158	14,589,396	**51,330,180**
SA-SAGD CAPEX & OPEX[2]	1,484,356	1,442,184	1,661,186	20,463,138	12,569,963	3,152,997	6,813,700	9,788,080	7,839,469	**65,215,072**
SA-SAGD Gas Expense[3]	0	0	0	0	52,724	786,251	958,678	722,781	882,020	**3,402,454**
SA-SAGD Cash Flow[4]	(1,484,356)	(1,442,184)	(1,661,186)	(20,463,138)	(12,622,687)	1,277,541	8,678,459	4,562,298	5,867,907	**(17,287,346)**
Cold Lake Royalty Rate	30%	30%	30%	25%	28%	31%	34%	34%	35%	
Cold Lake Royalty Impact	(445,307)	(432,655)	(498,356)	(5,115,785)	(3,510,369)	395,006	2,936,257	1,543,601	2,077,149	**(3,050,459)**
SA-SAGD Cash Flow[5]	(1,039,049)	(1,009,529)	(1,162,830)	(15,347,354)	(9,112,318)	882,535	5,742,202	3,018,697	3,790,758	**(14,236,887)**
Total Cold Lake Payable Royalties[6]	**157,264,756**	**375,655,398**	**338,663,276**	**575,819,711**	**438,239,877[7]**	**628,604,615[7]**	**935,665,145[7]**	**678,964,474[7]**	**599,432,772**	**2,046,835,913**

[1] Estimated, see section 6.2 for assumptions
[2] Based on IETP claim form submissions, see sections 6.3 and 6.4
[3] Estimated, see section 6.6 for assumptions
[4] Cash flow before royalties
[5] Cash flow after royalties
[6] Total Cold Lake royalties paid, which include SA-SAGD costs and revenue. IETP credits are not included.
[7] Amendments to prior years were processed, therefore the royalties for these years has been revised

6.6 Cash flow

As the SA-SAGD pilot is part of Imperial Oil's Cold Lake Production Project, injection and production volumes are blended with Mahkeses plant volumes, and thus revenue and net gas costs are not calculated separately. Recovered solvent from the pilot will ultimately reduce diluent purchases made at the Mahkeses plant which are required for blending and shipping, but for the purposes of this report, solvent recovery is shown as a theoretical revenue stream. Estimates have been made for:

Bitumen revenue (section 6.2)
Recovered solvent revenue - based on a recovered volume (section 6.1) and solvent price (section 6)
Net natural gas expense - based on a net gas volume (section 6.1) and gas (section 6)

Capital and operating costs are known to be:

Capital costs (see section 6.3)
Operating costs (section 6.4 – includes operating and injectant costs)
Royalties (section 6.5)

Cash flow, as shown in table in section 6.5, is estimated to be:

Cash Flow = Revenue – Costs – Royalties
= (Bitumen + Solvent Revenue) – (Capital + Net Gas + Operating Costs) – Royalties

6.7 Cumulative project costs and net revenue

Cumulative project costs as of the end of the pilot are:

C$	Up to YE 2010	2011	2012	2013	Total (to YE 2013)
Total Capital Costs	26,133,883	78,212	-6,371	0	**26,205,724**
Total Operating Costs	13,828,517	1,048,829	2,356,755	2,373,927	**19,608,027**
Total Injectant Costs	811,423	5,686,659	7,437,696	5,465,542	**19,401,319**
Total Net Gas Costs	838,975	958,678	722,781	882,020	**3,402,453**
Total Costs	**41,612,798**	**7,772,378**	**10,510,860**	**8,721,489**	**68,617,524**

[1] Estimated, see section 6.6 for assumptions

Cumulative project revenue from 2010 to 2013 is:

C$	2010	2011	2012	2013	Total (to YE 2013)
Bitumen Revenue	4,898,707	12,877,231	10,439,665	10,323,285	**38,538,887**
Solvent Revenue	318,082	3,573,606	4,633,493	4,266,111	**12,791,293**
Total Revenue	**5,216,789**	**16,450,837**	**15,073,158**	**14,589,396**	**51,330,180**

[2] Estimated, see section 6.2 for assumptions
[3] Estimated, see section 6.6 for assumptions

6.8 Deviations from budgeted costs

Changes from actual versus budgeted costs were outlined in the 2009 annual progress report. There have since been no further changes.

7 Facilities

7.1 Major equipment items

Major equipment items include:

Injection side

- Steam separator to separate condensed water from the inlet steam line
- Diluent tank
- Diluent pump

Production side

- Rotary operated valve to direct production either to test or to the group line
- Production cooler
- Production test cooler
- Production test separator
- Gas test separator

7.2 Capacity limitation, operational issues, and equipment integrity

Capacity limitations

- 300 m^3/d (cold water equivalent) of dry steam injected per well pair
- 330 m^3/d water produced per well
- 20% (based on dry steam rate), or 60 m^3/d, maximum solvent injected per day
- 51.6 m^3/d solvent produced per day
- 84 m^3/d bitumen produced per well, without solvent assistance
- 110.4 m^3/d bitumen produced per well, with solvent assistance
- 2,100 m^3/d gas produced per well
- Total liquid from solvent assisted producing well: 492 m^3/d (330 m^3/d + 110.4 m^3/d + 51.6 m^3/d)

Operational Issues

No significant operational issues were encountered.

7.3 Process flow and site diagrams

For detailed PFDs and site diagrams, please refer to Appendix B.

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 10689B. To date, the pilot has been in full compliance, and no regulatory issues have arisen.

8.2 Environmental Considerations

The SA-SAGD 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 with 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. The system, known as RegFrame, tracks commitments and notifies key personnel of activities for which the company is responsible. RegFrame includes information from numerous sources including directives, approvals, codes of practice, and specific local agreements. All requirements associated with the CLEP EIA and the EPEA are incorporated into applicable phases of the T13 SA-SAGD pilot life-cycle.

8.3 Air Quality

The SA-SAGD 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.

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 SA-SAGD pilot did not generate an increase in water demand.

The SA-SAGD pilot location does not lie within 100 m of a water body. Imperial constructs its facilities with the objective of maintaining drainage patterns and natural flow and managing surface water runoff. Presently Imperial conducts monitoring of lakes and streams/creeks in the CLO area as part of the Regional Surface Water Monitoring Program (IOR 2005).

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 SA-SAGD 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 permissible sound level (PSL).

8.7 Reclamation

The SA-SAGD pilot decommissioning and reclamation activities will be addressed in accordance with the AEPEA Approval 73534-00-04, as amended.

9 Summary - Operating Plan

9.1 Project schedule

Key milestones are as follows:

- End of Pilot Operations December 31, 2013 (except final seismic shoot in March 2014)
- Final Report Issued Q2, 2015

9.2 Changes in pilot operation

Pilot original objectives/milestones met and completed on December 31, 2013, with the exception of the final seismic shoot in March 2014. No changes to report post completion of the pilot.

9.3 Optimization strategies

No optimizations to report post completion of the pilot.

9.4 Salvage update

Wells continue to be operated by Cold Lake Operations and continue to be evaluated for SAGD/SA-SAGD performance in the Clearwater formation.

10 Interpretations and Conclusions

10.1 Overall performance assessment

The team feels that the pilot objectives have been met, as outlined below:

- Safely acquire high-quality data to allow for definite interpretation of pilot results – ensuring that testing was operational was the highest priority, as well as committing to a comprehensive sampling program.

- Provide sufficient information to assess whether SA-SAGD is a commercially viable recovery process at Cold Lake and Athabasca. In particular, the team's analysis of pilot results and demonstration of predictive capability made it feasible to assess the commercial viability of SA-SAGD.

- Gain necessary operation experience with SA-SAGD to enable future design of a cost-effective commercial application – specifically, the team was able to:
  - Demonstrate the ability to operate at a constant injection pressure
  - Capture impact of solvent on SAGD
  - Understand impact of skin development on producers and mitigation strategies

Overall, the T13 pilot was highly successful; it played an integral role in progressing SAGD/SA-SAGD technology, as well as provided valuable hands-on experience from an operations perspective.

Difficulties Encountered

Both well pairs experienced an increasing near-wellbore pressure drop. Starting in 2013, this pressure drop interfered with the operations as the flowing bottomhole pressures (FBHPs) were lower than the surface separator pressure, resulting in a lack of fluid column maintained above the pump. The FBHPs declined to the point where this fluid column could not be sustained and gas interference effects became apparent. These effects complicated the interpretation of the post solvent-switch production effects of both well pairs.

Technical and Economic Viability

SA-SAGD is deemed to be a technical success. Economic viability will be evaluated on a case by case basis and will be dependent on a number of factors, such as commodity price, reservoir quality, reservoir characteristics (gas/water thief zones or other heterogeneities), and solvent recovery.

Overall Effect on Gas / Bitumen Recovery

The pilot was not designed to assess ultimate recovery levels relative to SAGD. Pilot data clearly shows an acceleration in oil recovery vs. SAGD.

Future expansion or commercial field application

Imperial is evaluating application of SA-SAGD at its upcoming commercial SAGD developments in Athabasca (Aspen) and at Cold Lake (Midzaghe).

11 Energy and Material Balance

11.1 Gross Balances

Pilot set up at T13 is unique, as it is tied back to Mahkeses plant, which utilizes Heat Recovery Steam Generation (HRSG), and serves other CSS pads along with the pilot. For that reason, SA-SAGD metrics [such as electricity consumed, boiler steam details, in-situ combustion and process air and fresh water] and any incremental over SAGD, cannot be accurately determined for this project.

11.2 Produced Materials

Produced water, oil, gas and diluent volumes by well are summarized in section 2.3.
There are no disposal wells included in this IETP project. The standard API of Cold Lake is 11.
Volume of diluent purchased is summarized in section 2.3.

There has been no sand production at T13.
An estimate of natural gas burned is included in section 6.1.

Appendix A

Monthly Injection

&

Production Volumes

2009

Steam Injected (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
1-Nov	982.6	955.9	879.4	937.3
1-Dec	402.3	387.8	296.7	439.8

Produced water (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
1-Nov	36.8	54.1	55.2	65.1
1-Dec	319.5	460.5	493.8	616.5

2010

Steam Injected (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-10	157.6	129.9	0.0	0.0
Feb-10	1,384.4	1,317.1	915.3	896.1
Mar-10	1,483.3	1,452.1	1,765.0	1,497.1
Apr-10	1,153.9	1,161.7	1,168.8	1,116.8
May-10	2,025.7	2,027.2	1,728.2	1,953.8
Jun-10	1,677.8	1,932.0	1,399.1	1,826.0
Jul-10	0.0	1,116.2	0.0	1,145.4
Aug-10	0.0	3,720.7	0.0	4,132.5
Sep-10	0.0	3,633.1	0.0	4,234.7
Oct-10	0.0	4,200.9	0.0	4,152.6
Nov-10	0.0	4,165.8	0.0	4,538.4
Dec-10	0.0	4,451.4	0.0	5,199.9

Produced water (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-10	119.3	189.8	0.0	0.0
Feb-10	990.8	1,010.5	636.7	1,027.6
Mar-10	1,176.7	1,458.7	1,681.2	1,319.6
Apr-10	946.0	1,040.8	1,076.2	849.6
May-10	1,335.3	989.8	1,267.5	993.5
Jun-10	2,067.1	500.9	2,397.9	616.7
Jul-10	441.7	0.0	1,212.5	0.0
Aug-10	3,813.2	0.0	4,516.7	0.0
Sep-10	3,618.4	0.0	4,069.5	0.0
Oct-10	4,123.5	0.0	4,568.7	0.0
Nov-10	3,983.7	0.0	4,747.9	0.0
Dec-10	4,804.9	0.0	5,748.5	0.0

Produced hydrocarbon liquid (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-10	0.0	0.0	0.0	0.0
Feb-10	28.8	3.9	7.1	0.5
Mar-10	34.4	23.0	8.7	14.6
Apr-10	101.4	32.3	48.3	26.4
May-10	266.2	189.7	298.2	203.2
Jun-10	369.2	109.4	362.8	133.0
Jul-10	140.8	0.0	413.3	0.0
Aug-10	907.0	0.0	1,285.0	0.0
Sep-10	829.2	0.0	1,029.7	0.0
Oct-10	790.7	0.0	1,167.5	0.0
Nov-10	885.9	0.0	1,657.7	0.0
Dec-10	1,067.1	0.0	1,210.7	0.0

Diluent (purchased, in m^3):

	T13
Jan-10	0.0
Feb-10	0.0
Mar-10	0.0
Apr-10	0.0
May-10	0.0
Jun-10	0.0
Jul-10	0.0
Aug-10	0.0
Sep-10	0.0
Oct-10	418.1
Nov-10	653.1
Dec-10	300.0

Injected diluent volumes (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-10	0.0	0.0	0.0	0.0
Feb-10	0.0	0.0	0.0	0.0
Mar-10	0.0	0.0	0.0	0.0
Apr-10	0.0	0.0	0.0	0.0
May-10	0.0	0.0	0.0	0.0
Jun-10	0.0	0.0	0.0	0.0
Jul-10	0.0	0.0	0.0	0.0
Aug-10	0.0	0.0	0.0	0.0
Sep-10	0.0	0.0	0.0	0.0
Oct-10	0.0	0.0	0.0	309.5
Nov-10	0.0	0.0	0.0	616.3
Dec-10	0.0	0.0	0.0	281.5

Produced diluent (by well, m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-13	0.0	0.0	0.0	0.0
Feb-13	0.0	0.0	0.0	0.0
Mar-13	0.0	0.0	0.0	0.0
Apr-13	0.0	0.0	0.0	0.0
May-13	0.0	0.0	0.0	0.0
Jun-13	0.0	0.0	0.0	0.0
Jul-13	0.0	0.0	0.0	0.0
Aug-13	0.0	0.0	0.0	0.0
Sep-13	0.0	0.0	0.0	0.0
Oct-13	0.0	0.0	129.0	0.0
Nov-13	0.0	0.0	342.5	0.0
Dec-13	0.0	0.0	129.0	0.0

Produced gas (by well, in $10^3 m^3$):

	T13-01	T13-02	T13-03	T13-04
Jan-10	0.0	0.0	0.0	0.0
Feb-10	0.0	0.0	0.0	0.0
Mar-10	0.0	0.0	0.0	0.0
Apr-10	0.7	0.2	0.4	0.1
May-10	2.6	1.6	3.3	1.9
Jun-10	2.8	0.8	2.7	1.2
Jul-10	1.1	0.0	3.1	0.0
Aug-10	6.8	0.0	9.6	0.0
Sep-10	6.2	0.0	7.7	0.0
Oct-10	5.9	0.0	8.8	0.0
Nov-10	6.6	0.0	12.4	0.0
Dec-10	8.0	0.0	9.1	0.0

2011

Steam (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-11	0.0	4,516.2	0.0	4,830.3
Feb-11	0.0	3,613.4	0.0	4,214.0
Mar-11	0.0	4,133.7	0.0	4,510.2
Apr-11	0.0	3,993.4	0.0	4,374.0
May-11	0.0	4,230.6	0.0	4,925.8
Jun-11	0.0	4,008.4	0.0	4,686.1
Jul-11	0.0	3,821.9	0.0	4,263.7
Aug-11	0.0	4,850.0	0.0	5,327.7
Sep-11	0.0	2,139.4	0.0	2,447.3
Oct-11	0.0	2,860.8	0.0	2,871.2
Nov-11	0.0	7,066.3	0.0	8,152.3
Dec-11	0.0	5,299.9	0.0	6,388.8

Produced water (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-11	4,665.0	0.0	5,307.6	0.0
Feb-11	3,091.0	0.0	3,802.5	0.0
Mar-11	3,701.1	0.0	4,077.2	0.0
Apr-11	3,577.5	0.0	4,139.4	0.0
May-11	3,803.0	0.0	4,797.2	0.0
Jun-11	3,655.6	0.0	4,633.8	0.0
Jul-11	3,829.6	0.0	4,094.5	0.0
Aug-11	4,403.2	0.0	5,120.0	0.0
Sep-11	3,505.0	0.0	4,014.4	0.0
Oct-11	1,717.8	0.0	1,819.4	0.0
Nov-11	5,300.0	0.0	6,000.0	0.0
Dec-11	5,396.5	0.0	6,589.6	0.0

Produced hydrocarbon liquid (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-11	1,034.4	0.0	1,681.0	0.0
Feb-11	954.2	0.0	1,466.5	0.0
Mar-11	1,147.4	0.0	1,759.9	0.0
Apr-11	1,134.5	0.0	1,827.4	0.0
May-11	1,051.4	0.0	1,712.1	0.0
Jun-11	1,127.6	0.0	1,550.1	0.0
Jul-11	1,009.4	0.0	1,856.6	0.0
Aug-11	1,029.4	0.0	2,095.6	0.0
Sep-11	1,262.5	0.0	1,938.8	0.0
Oct-11	2,083.7	0.0	2,258.6	0.0
Nov-11	894.2	0.0	997.7	0.0
Dec-11	1,056.5	0.0	1,905.6	0.0

Diluent (purchased, in m^3):

	T13
Jan-11	865.8
Feb-11	694.4
Mar-11	964.3
Apr-11	826.7
May-11	783.6
Jun-11	663.4
Jul-11	713.3
Aug-11	777.4
Sep-11	422.7
Oct-11	0.0
Nov-11	420.5
Dec-11	973.2

Injected diluent volumes (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-11	0	0	0	916.1
Feb-11	0	0	0	702.3
Mar-11	0	0	0	895.9
Apr-11	0	0	0	881.8
May-11	0	0	0	686.8
Jun-11	0	0	0	678.8
Jul-11	0	0	0	683.5
Aug-11	0	0	0	778.3
Sep-11	0	0	0	427.7
Oct-11	0	0	0	0
Nov-11	0	0	0	438.8
Dec-11	0	0	0	883.9

Produced diluent (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-13	0.0	0.0	340.0	0.0
Feb-13	0.0	0.0	412.0	0.0
Mar-13	0.0	0.0	483.9	0.0
Apr-13	0.0	0.0	523.4	0.0
May-13	0.0	0.0	563.8	0.0
Jun-13	0.0	0.0	299.2	0.0
Jul-13	0.0	0.0	568.6	0.0
Aug-13	0.0	0.0	730.8	0.0
Sep-13	0.0	0.0	560.2	0.0
Oct-13	0.0	0.0	428.1	0.0
Nov-13	0.0	0.0	144.3	0.0
Dec-13	0.0	0.0	402.5	0.0

Produced gas (by well, in 10^3m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-11	12.1	0	53.5	0
Feb-11	7.1	0	45.8	0
Mar-11	5.2	0	42.9	0
Apr-11	5.4	0	35	0
May-11	5.5	0	41.7	0
Jun-11	7	0	25	0
Jul-11	7.1	0	2.8	0
Aug-11	4.4	0	2.2	0
Sep-11	8	0	8	0
Oct-11	85.3	0	84.4	0
Nov-11	2.8	0	2.8	0
Dec-11	5.4	0	3.3	0

2012

Steam (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-12	0.0	5,328.3	0.0	5,491.7
Feb-12	0.0	4,933.4	0.0	4,987.4
Mar-12	0.0	5,033.2	0.0	5,208.2
Apr-12	0.0	4,571.1	0.0	5,473.8
May-12	0.0	4,761.5	0.0	5,614.1
Jun-12	0.0	4,058.5	0.0	5,844.2
Jul-12	0.0	4,519.7	0.0	5,857.3
Aug-12	0.0	4,511.6	0.0	5,781.8
Sep-12	0.0	3,136.2	0.0	3,779.3
Oct-12	0.0	4,993.3	0.0	4,212.1
Nov-12	0.0	4,704.0	0.0	5,632.4
Dec-12	0.0	4,934.0	0.0	4,790.9

Produced water (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-12	4,828.3	0.0	5,339.4	0.0
Feb-12	4,526.7	0.0	4,942.3	0.0
Mar-12	4,788.9	0.0	5,345.9	0.0
Apr-12	4,323.3	0.0	5,254.5	0.0
May-12	4,480.0	0.0	5,315.9	0.0
Jun-12	4,085.8	0.0	5,350.2	0.0
Jul-12	3,968.8	0.0	5,308.6	0.0
Aug-12	4,287.0	0.0	5,330.9	0.0
Sep-12	3,361.1	0.0	3,563.0	0.0
Oct-12	4,267.4	0.0	4,391.0	0.0
Nov-12	3,990.3	0.0	4,605.4	0.0
Dec-12	4,513.2	0.0	3,858.5	0.0

Produced hydrocarbon liquid (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-12	971.3	0.0	1,743.3	0.0
Feb-12	911.9	0.0	1,773.8	0.0
Mar-12	953.6	0.0	2,115.9	0.0
Apr-12	907.6	0.0	2,275.9	0.0
May-12	926.6	0.0	2,383.8	0.0
Jun-12	1,242.6	0.0	1,857.4	0.0
Jul-12	1,613.9	0.0	1,454.4	0.0
Aug-12	1,729.5	0.0	1,188.2	0.0
Sep-12	1,445.3	0.0	725.9	0.0
Oct-12	2,267.6	0.0	1,051.6	0.0
Nov-12	1,814.1	0.0	1,104.1	0.0
Dec-12	1,902.5	0.0	718.0	0.0

Diluent (purchased, in m^3):

	T13
Jan-12	794.7
Feb-12	850.1
Mar-12	796.1
Apr-12	1,034.5
May-12	912.2
Jun-12	911.1
Jul-12	822.9
Aug-12	981.9
Sep-12	674.4
Oct-12	1,044.5
Nov-12	1,035.7
Dec-12	977.9

Summary of injected diluent volumes (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-12	0	0.0	0	772.6
Feb-12	0	0.0	0	866.0
Mar-12	0	0.0	0	760.6
Apr-12	0	0.0	0	1,009.4
May-12	0	91.4	0	785.9
Jun-12	0	944.1	0	0.0
Jul-12	0	860.5	0	0.0
Aug-12	0	952.1	0	0.0
Sep-12	0	639.8	0	0.0
Oct-12	0	1,029.1	0	0.0
Nov-12	0	1,003.0	0	0.0
Dec-12	0	1,013.7	0	0.0

Produced diluent (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-13	0.0	0.0	363.0	0.0
Feb-13	0.0	0.0	473.8	0.0
Mar-13	0.0	0.0	616.3	0.0
Apr-13	0.0	0.0	682.0	0.0
May-13	13.8	0.0	725.4	0.0
Jun-13	293.9	0.0	455.4	0.0
Jul-13	369.2	0.0	310.9	0.0
Aug-13	423.8	0.0	216.5	0.0
Sep-13	370.1	0.0	98.1	0.0
Oct-13	585.8	0.0	107.3	0.0
Nov-13	473.6	0.0	115.4	0.0
Dec-13	533.5	0.0	77.4	0.0

Produced gas (by well, in $10^3 m^3$):

	T13-01	T13-02	T13-03	T13-04
Jan-12	3.5	0	2.0	0
Feb-12	4.1	0	1.7	0
Mar-12	4.1	0	2.4	0
Apr-12	6.0	0	2.1	0
May-12	3.8	0	2.1	0
Jun-12	2.0	0	2.2	0
Jul-12	2.2	0	2.5	0
Aug-12	2.2	0	3.4	0
Sep-12	10.2	0	2.0	0
Oct-12	8.4	0	1.9	0
Nov-12	2.1	0	2.5	0
Dec-12	3.1	0	1.3	0

2013

Steam volumes (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-13	0.0	4960.1	0.0	4356.0
Feb-13	0.0	3957.7	0.0	3338.2
Mar-13	0.0	4660.0	0.0	4820.8
Apr-13	0.0	2150.1	0.0	2148.6
May-13	0.0	5045.7	0.0	4027.8
Jun-13	0.0	5200.5	0.0	4024.2
Jul-13	0.0	4458.4	0.0	3454.0
Aug-13	0.0	5388.9	0.0	4252.5
Sep-13	0.0	3567.9	0.0	2913.6
Oct-13	0.0	6089.0	0.0	6058.3
Nov-13	0.0	4780.6	0.0	4796.0
Dec-13	0.0	4522.7	0.0	4584.6

Produced water (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-13	4530.6	0.0	4145.9	0.0
Feb-13	3822.2	0.0	3923.4	0.0
Mar-13	4274.7	0.0	4451.0	0.0
Apr-13	3424.3	0.0	2485.6	0.0
May-13	4010.1	0.0	1989.2	0.0
Jun-13	4649.9	0.0	5357.0	0.0
Jul-13	4778.4	0.0	3827.9	0.0
Aug-13	4250.6	0.0	3593.4	0.0
Sep-13	3268.1	0.0	4104.5	0.0
Oct-13	4188.8	0.0	4721.9	0.0
Nov-13	3299.1	0.0	3533.7	0.0
Dec-13	6416.8	0.0	3552.6	0.0

Produced hydrocarbon liquid (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-13	1942.3	0.0	805.7	0.0
Feb-13	1595.7	0.0	760.5	0.0
Mar-13	1833.4	0.0	834.0	0.0
Apr-13	1916.0	0.0	486.9	0.0
May-13	2690.3	0.0	370.6	0.0
Jun-13	2841.0	0.0	1008.6	0.0
Jul-13	2273.8	0.0	1141.3	0.0
Aug-13	1713.5	0.0	1006.9	0.0
Sep-13	1348.3	0.0	1447.7	0.0
Oct-13	1269.1	0.0	1578.3	0.0
Nov-13	1088.3	0.0	684.1	0.0
Dec-13	2255.4	0.0	635.8	0.0

Diluent (purchased, in m^3):

	T13
Jan-13	918.9
Feb-13	602.1
Mar-13	908.2
Apr-13	422.0
May-13	904.8
Jun-13	1027.0
Jul-13	114.7
Aug-13	783.6
Sep-13	59.4
Oct-13	553.3
Nov-13	557.9
Dec-13	873.3

Injected diluent volumes (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-13	0.0	847.3	0.0	0.0
Feb-13	0.0	635.1	0.0	0.0
Mar-13	0.0	891.8	0.0	0.0
Apr-13	0.0	421.2	0.0	0.0
May-13	0.0	857.0	0.0	0.0
Jun-13	0.0	1031.7	0.0	0.0
Jul-13	0.0	97.0	0.0	0.0
Aug-13	0.0	691.8	0.0	0.0
Sep-13	0.0	106.2	0.0	0.0
Oct-13	0.0	491.7	0.0	0.0
Nov-13	0.0	524.1	0.0	0.0
Dec-13	0.0	892.4	0.0	0.0

Produced diluent (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-13	562.3	0.0	80.0	0.0
Feb-13	468.9	0.0	94.9	0.0
Mar-13	437.7	0.0	73.8	0.0
Apr-13	444.4	0.0	40.3	0.0
May-13	583.4	0.0	49.7	0.0
Jun-13	754.6	0.0	134.5	0.0
Jul-13	567.4	0.0	102.9	0.0
Aug-13	449.1	0.0	103.1	0.0
Sep-13	325.5	0.0	171.3	0.0
Oct-13	229.9	0.0	63.8	0.0
Nov-13	234.7	0.0	35.4	0.0
Dec-13	398.8	0.0	23.6	0.0

Produced gas (by well, in 10^3m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-13	3.8	0.0	1.3	0.0
Feb-13	4.1	0.0	1.8	0.0
Mar-13	5.7	0.0	2.6	0.0
Apr-13	5.0	0.0	0.7	0.0
May-13	8.1	0.0	3.0	0.0
Jun-13	7.5	0.0	3.8	0.0
Jul-13	10.7	0.0	3.4	0.0
Aug-13	8.6	0.0	3.8	0.0
Sep-13	9.7	0.0	8.3	0.0
Oct-13	9.6	0.0	8.2	0.0
Nov-13	5.6	0.0	3.3	0.0
Dec-13	8.3	0.0	1.9	0.0

Appendix B

Process Flow Diagrams (PFDs)

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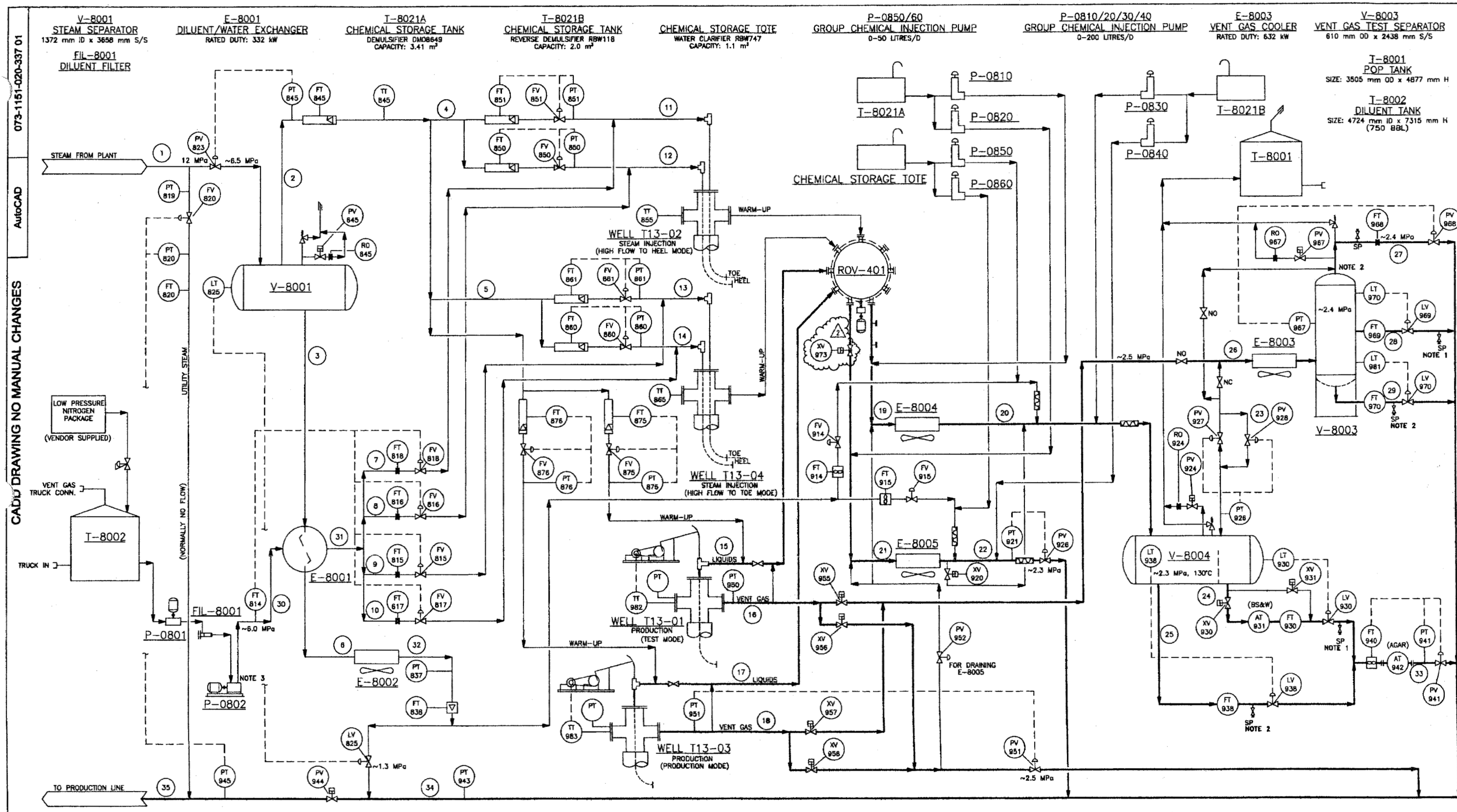
Site Maps

073-1151-020-337 01

AutoCAD

CADD DRAWING NO MANUAL CHANGES



CONSTRUCTION NOTES:

1. PROPORTIONAL SAMPLER.
2. SAMPLE POINTS MANUAL STYLE.
3. MULTI-STAGE CENTRIFUGAL PUMP.

P-0801	P-0802	E-8002	E-8004	E-8005	ROV-401	V-8004
DILUENT BOOSTER PUMP	DILUENT INJECTION PUMP	WATER COOLER	PRODUCTION TEST COOLER	PRODUCTION COOLER	8-WAY ROTARY SELECTOR VALVE	PRODUCTION TEST SEPARATOR
66 m³/d	66 m³/d	RATED DUTY: 3498 kW	RATED DUTY: 1265 kW	RATED DUTY: 1265 kW		1524 mm ID x 6706 mm S/S

Imperial Oil

Esso

IMPERIAL OIL RESOURCES

NO.	DATE	REVISIONS	DRAWN	CHECK	DESIGN	APPR.
2	09 03 18	RE-ISSUED FOR CONSTRUCTION PER MOC C-4481 (XY.2006.28284)	MG	DAP	SAS	KSC
1	08 11 14	RE-ISSUED FOR CONSTRUCTION PER MOC C-4413 (XY.2006.28284)	DAP	MG	KSC	AMB
0	08 08 08	ISSUED FOR CONSTRUCTION (XY.2006.28284)	LPC	MG	KSC	AMB

DRAFTING | ENGINEERING

IOR DWG NO. | TITLE

REFERENCE DRAWINGS

SEAL/STAMP

PERMIT TO PRACTICE
IMPERIAL OIL RESOURCES
Signature
Date Mar 26/09
PERMIT NUMBER: P00884
The Association of Professional Engineers, Geologists and Geophysicists of Alberta

PERMIT

PROJECT ENGINEERING

APPROVED FOR CONSTRUCTION
DATE Mar 26/09 REV. 2

CLPP MAHKESES FIELD PHASES 11-13
PAD T13 SA-SAGD FACILITIES
PROCESS FLOW DIAGRAM

CONTRACTOR NAME: COLT ENGINEERING CORPORATION

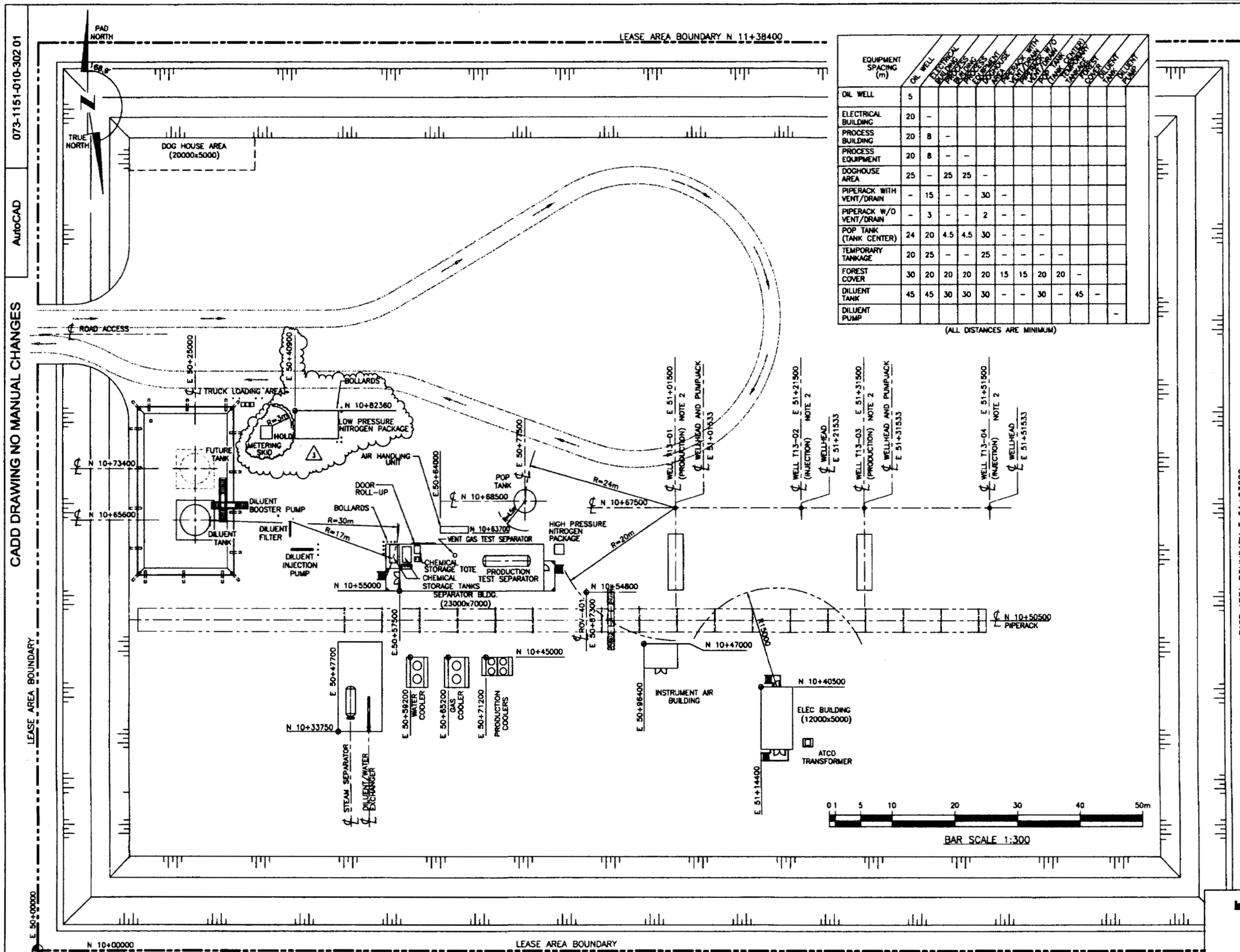
CONTRACTOR DWG NUMBER: XY.2006.28284

SCALE: NONE

IOR DRAWING NUMBER: 073-1151-020-337 01

REV.: 2

Filename: H:\FILENET\073-1151-020-337-01.DWG User ID: MBGRIGG Plot date/time: March 18, 2009 - 3:54pm XREF drawings: IMAGE attachments:



EQUIPMENT SPACING (m)	OIL WELL	ELECTRICAL BUILDING	PROCESS BUILDING	PROCESS EQUIPMENT	DOGHOUSE AREA	PIPERACK WITH VENT/DRAIN	PIPERACK W/O VENT/DRAIN	POP TANK (TANK CENTER)	TEMPORARY TANKAGE	FOREST COVER	DILUENT TANK	DILUENT PUMP
OIL WELL	5											
ELECTRICAL BUILDING	20	–										
PROCESS BUILDING	20	8	–									
PROCESS EQUIPMENT	20	8	–	–								
DOGHOUSE AREA	25	–	25	25	–							
PIPERACK WITH VENT/DRAIN	–	15	–	–	30	–						
PIPERACK W/O VENT/DRAIN	–	3	–	–	2	–	–					
POP TANK (TANK CENTER)	24	20	4.5	4.5	30	–	–	–				
TEMPORARY TANKAGE	20	25	–	–	25	–	–	–	–			
FOREST COVER	30	20	20	20	20	15	15	20	20	–		
DILUENT TANK	45	45	30	30	30	–	–	30	–	45	–	
DILUENT PUMP												–

(ALL DISTANCES ARE MINIMUM)

MAJOR EQUIPMENT LIST

TAG No.	DESCRIPTION	LOCATION
E-8001	DILUENT/WATER EXCHANGER	AS SHOWN
E-8002	WATER COOLER	AS SHOWN
E-8003	GAS COOLER	AS SHOWN
E-8004	PRODUCTION TEST COOLER	AS SHOWN
E-8005	PRODUCTION COOLER	AS SHOWN
HTR-8110/1/2/3/4/5	BUILDING HEATERS	SEPARATOR BLDG.
EF-8010/1/2/3	EXHAUST FANS	SEPARATOR BLDG.
HTR-0004/5/6	BUILDING HEATERS	ELEC. BUILDING
EF-0003/4	EXHAUST FANS	ELEC. BUILDING
FIL-8001	DILUENT FILTER	AS SHOWN
K-8021	INSTR. AIR COMP. PACKAGE	INST AIR BLDG.
P-0801	DILUENT BOOSTER PUMP	AS SHOWN
P-0802	DILUENT INJECTION PUMP	AS SHOWN
P-0810/20/30/40/50/60	GROUP CHEM. INJ. PUMP	SEPARATOR BLDG.
T-8001	POP TANK	AS SHOWN
T-8002	DILUENT TANK	AS SHOWN
T-8021A/B	CHEMICAL STORAGE TANK	SEPARATOR BLDG.
CHEMICAL STORAGE TOTE		SEPARATOR BLDG.
V-8001	STEAM SEPARATOR	AS SHOWN
V-8003	VENT GAS SEPARATOR	SEPARATOR BLDG.
V-8004	PRODUCTION TEST	SEPARATOR BLDG.
ROV-401	8-WAY ROTARY SELECTOR VALVE	AS SHOWN
T-13-01/03	PRODUCTION WELLHEADS	LEASE AREA
T-13-02/04	INJECTION WELLHEADS	LEASE AREA
–	LP NITROGEN PACKAGE	AS SHOWN
–	HP NITROGEN PACKAGE	AS SHOWN
MAU-8010	MAKE UP AIR UNIT	SEPARATOR BLDG.
HAH-8010	AIR HANDLING UNIT	AS SHOWN

DESIGN NOTES:

1. LOCATION OF GROUNDWATER EVALUATION WELL (GEW) TO BE SUPPLIED BY FIELD.
2. WELLHEAD AND PUMPJACK IS OFFSET 33mm EAST OF WELL BORE.

GENERAL CONSTRUCTION NOTES:

A. CONSTRUCTION CONTRACTOR SHALL:
- LOCATE AND INSTALL ALL HYDROTEST VENTS AND DRAINS AS PER DRAWING 073-0051-080-044 01.
- PAINT PSV AND CAR SEALED VALVES WITH INTERNATIONAL ORANGE ENAMEL PAINT.
- INSTALL CAR SEALED VALVES WITH THE VALVE STEM IN THE HORIZONTAL (PREFERRED) OR DOWNWARD POSITION UNLESS OTHERWISE NOTED.
- GREASE THE UNDERSIDE OF ALL SLIDING PIPE SHOE BASE PLATES AND ALL DIRECTIONAL ANCHORS WITH HIGH TEMPERATURE GREASE (RATED TO -40°C AND 100°C).
- LOCATE AND INSTALL PERSONNEL PROTECTION ON LINES AS PER EBP 14-1-1, PAR.4.14 AND AS PER PIPING GENERAL ARRANGEMENTS.
- DO NOT PLACE VENTS AND DRAINS ON HYDROCARBON PIPING AND PIPELINES WITHIN 15m OF THE ELECTRICAL BUILDING AND 30m OF THE DOGHOUSE AREA.

B. INSTRUMENTATION CONNECTIONS:
- PRESSURE CONNECTIONS ARE 3/4 NPT UNLESS NOTED OTHERWISE. INSTALL AS PER DETAIL 4 ON DRAWING 073-0051-080-044 01.
- TEMPERATURE CONNECTIONS ARE 1 NPT UNLESS NOTED OTHERWISE.
- ORIFICE TAPS ON HORIZONTAL PIPES TO BE HORIZONTAL IN LIQUID AND STEAM SERVICE AND VERTICAL (UPWARD) IN GAS SERVICE. PROVIDE NIPPLES AND GATE VALVES AS PER LINE SPECIFICATION. UNUSED TAPS TO BE PLUGGED WITH HXHD PLUGS COMPLYING WITH PIPING SPECIFICATIONS AND SEAL WELDED. ROOT PASS ON THE ORIFICE FLANGE/PIPE BUTT WELD TO BE GROUND SMOOTH TO THE INSIDE PIPE WALL.

C. DEVIATION/DECISION RECORD:
- MOC-109 DEVIATION TO EBP 3-18-1, PAR.7.3.1. DO NOT INSTALL GUSSETS ON SMALL BORE (<NPS 2) CONNECTIONS.
- MOC-439 DEVIATION TO EBP 19-1-1, TABLE 3. DO NOT PRIME OR PAINT ANY INSULATED PIPING.
- MOC-442 DEVIATION TO EBP 3-30-3, USE OF PLATED CARBON STEEL COMPRESSION FITTINGS WITH STAINLESS STEEL FERRULES IS ALLOWED IN AIR AND CHEMICAL SERVICE (PIPING CLASS ZJCEO).
- MOC-2185 DECISION RECORD, EQUIPMENT SPACING. SEE EQUIPMENT SPACING TABLE (THIS DRAWING).
- MOC-2574-DEVIATION TO EBP 18-200-1, USE OF CE>0.45<0.53 FOR FORGED BODY VALVES WITH PROCEDURES AS DESCRIBED.

CADD DRAWING NO MANUAL CHANGES

AutoCAD

073-1151-010-302 01

NO.	DATE	REVISIONS	DRAWN	CHECK	DESIGN	APPR.
3	09 05 25	RE-ISSUED FOR CONSTRUCTION - MOC C-4764 (XY.2008.28284)	MG	DAP	BAF	GME
2	08 11 13	ISSUED FOR CONSTRUCTION - MOC C-4405 (XY.2008.28284)	KJG	GBF	GCS	BAF
1	08 11 14	RE-ISSUED FOR CONSTRUCTION - MOC C-4413 (XY.2008.28284)	YW	MG	BAF	GME
0	08 08 15	ISSUED FOR CONSTRUCTION (XY.2008.28284)	CAR	MG	BAF	GME

DRAFTING | ENGINEERING

IOR DWG NO. | TITLE

REFERENCE DRAWINGS

SEAL/STAMP

PERMIT TO PRACTICE
IMPERIAL OIL RESOURCES
Signature
Date MAY 27. 2009
PERMIT NUMBER: P00884
The Association of Professional Engineers, Geologists and Geophysicists of Alberta
PERMIT

APPROVED FOR CONSTRUCTION
DATE 27-MAY-09 REV. 3
PROJECT ENGINEERING

Imperial Oil
Esso

IMPERIAL OIL RESOURCES

CLPP MAHKESES FIELD PHASES 11 - 13
PAD T13 SA-SAGD FACILITIES
PLOT PLAN

CONTRACTOR NAME	SCALE	IOR DRAWING NUMBER	REV.
COLT ENGINEERING CORPORATION	1:300	073-1151-010-302 01	3
CONTRACTOR DWG NUMBER: XY.2008.28284			