IETP Application No. 03-047

Imperial Oil Resources - Cold Lake Solvent Assisted - SAGD Pilot

2012 Annual Project Technical Report

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Appendix A: Process Flow Diagrams (PFDs) and Site Maps

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 5 – 20% by volume of hydrocarbon solvent (diluent) along with the injected dry 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.

The pilot operation is expected to last up to five years.

This report summarizes progress that was made in 2012. Pilot operations started 2012 with well-pair 1 operating in SAGD mode, while the adjacent well-pair 2 operated in SA-SAGD mode until May 2012, when a solvent switch was made. After the switch, well-pair 1 operated in SA-SAGD mode, while well-pair 2 operated in 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 were key members of the SA-SAGD team during 2012:

John Elliott, P.Eng. – Manager, Oil Sands Recovery Research
Larry Dittaro, P.Eng – SA-SAGD Pilot Team Lead
John Oxtoby, C.E.T. – SA-SAGD Pilot Engineering Technologist
Aisha Hammouda, P.Eng - SA-SAGD Pilot Engineer

2.2 Key activities

The pad started 2012 with well-pair 1 continuing to operate in SAGD mode (T13-01 &T13-02) and well-pair 2 in SA-SAGD mode (T13-03 & T13-04). At the end of May, the well-pair modes were switched, well-pair 1 operated in SA-SAGD mode, and well-pair 2 operated in SAGD mode.

Injection was shut in on September 21, 2012 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.

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
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 Materials

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

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
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

- 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 T13-03 and T13-01 include diluent recovered in the oil liquid phase. A breakdown is provided in Section 4.1.

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

- 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
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 Sand (m^3):

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

Produced gas (E^3m^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

2.4 Reserves

The most recent estimate of ultimate reserves is 2.1 MB (1.5 MB proved developed, 0.1 MB probable, and 0.5 MB cumulative production). Note that these reserves are associated with SAGD only, as solvent assisted recovery uplift needs further assessment to support additional reserves booking. This reserves estimate is slightly lower than initial estimates using industry data and simulation of Petrel-based models at the time of pilot approval, which was 2.8 MB.

3 Well Information

3.1 Well Layout Map

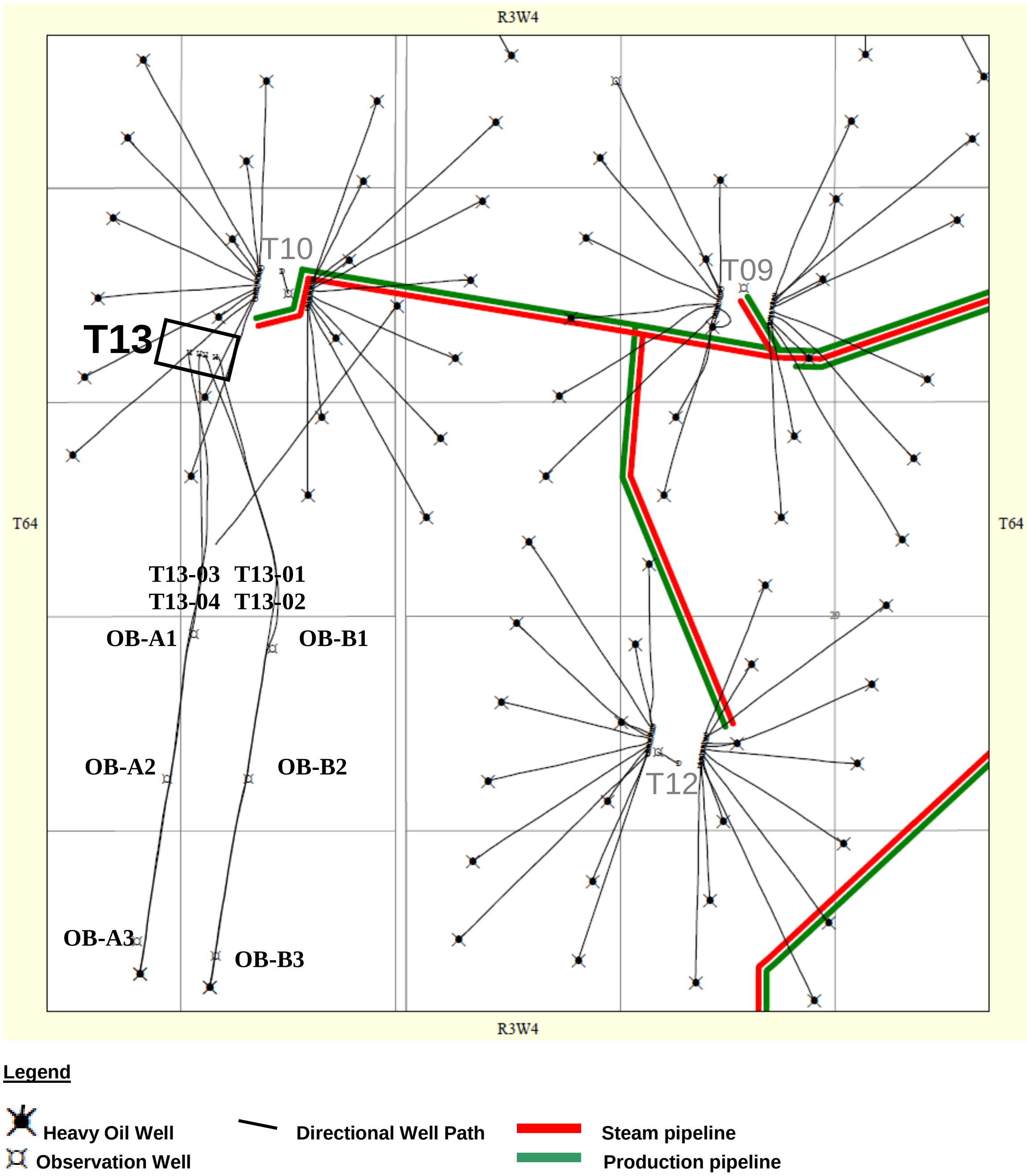


Figure 1: Location of SA-SAGD surface facilities and well trajectories

3.2 2012 drilling, completion, and work-over operations

There is no drilling or completion work to report for 2012. 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.

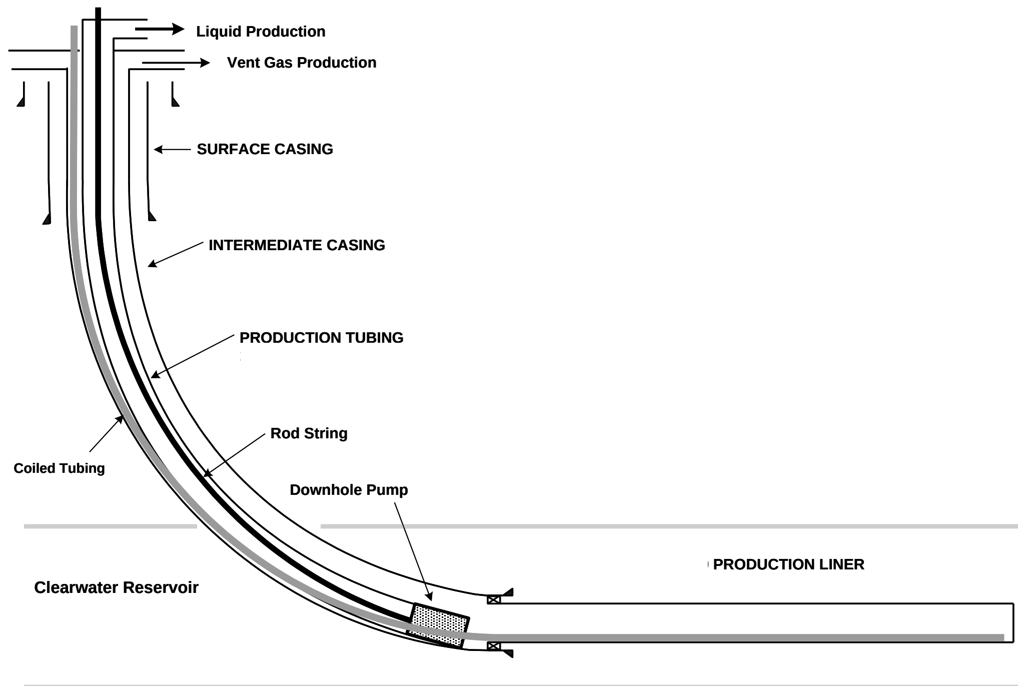
3.4 Well list and status

All wells are currently active. List as follows:

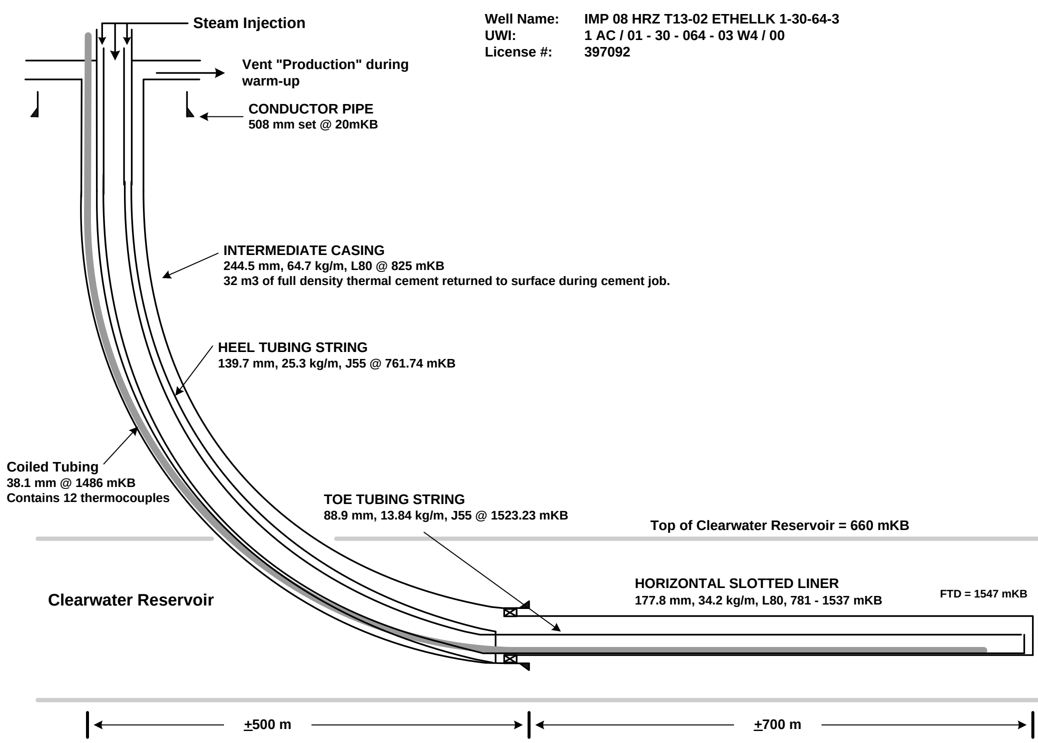
East well pair	1AB/01-30-064-03W4/0 (**T13-01**) producer
	1AC/01-30-064-03W4/0 (**T13-02**) injector
	1AA/08-30-064-03W4/0 (**OB-B1**) observation well
	1AD/08-30-064-03W4/0 (**OB-B2**) observation well
	1AA/01-30-064-03W4/0 (**OB-B3**) observation well
West well pair	1AB/02-30-064-03W4/0 (**T13-03**)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

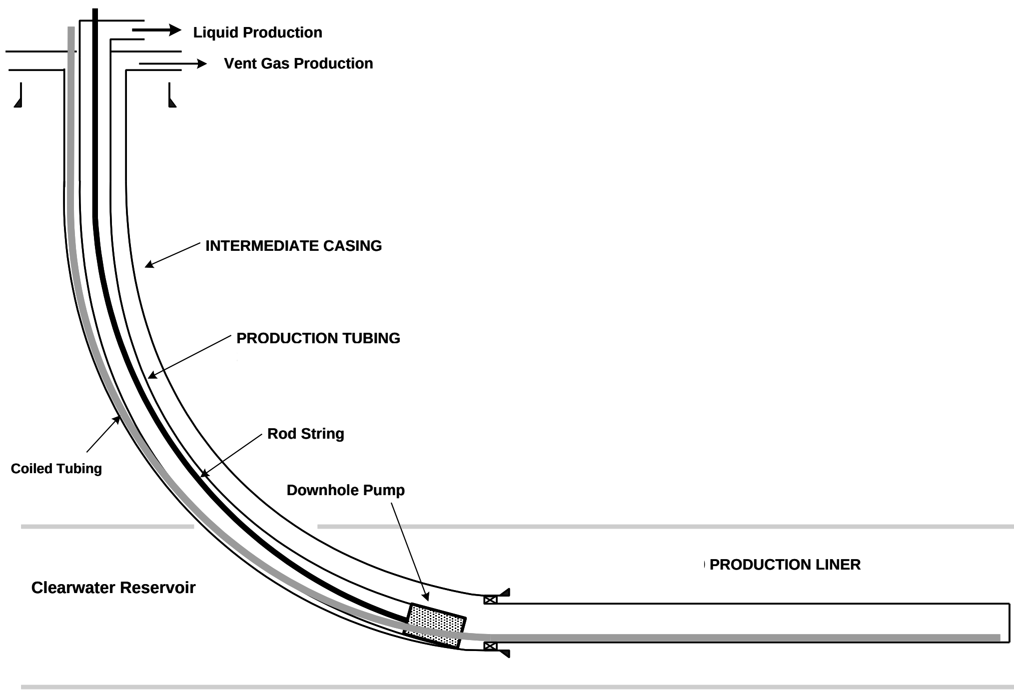
T13-01 (East producer) – SAGD schematic:



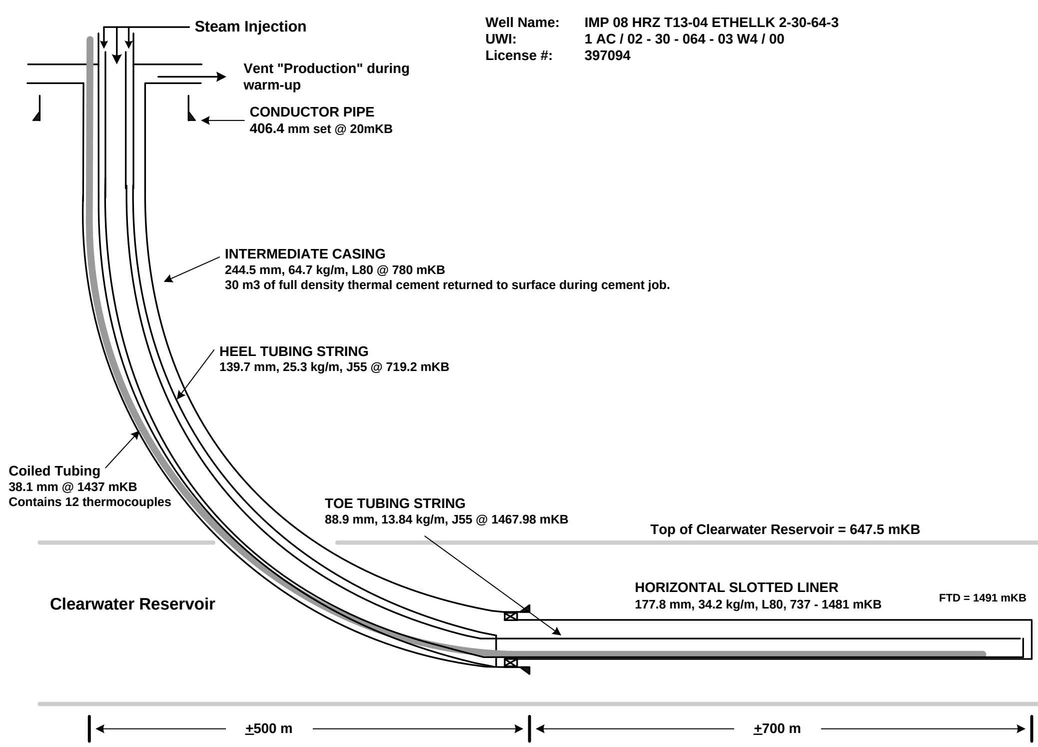
T13-02 (East injector):



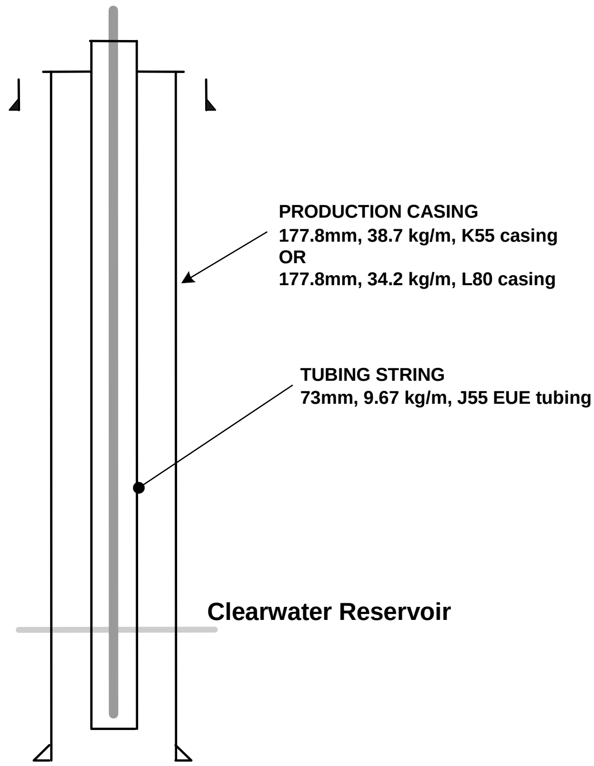
T13-03 (West producer) – SAGD schematic:



T13-04 (West injector):



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



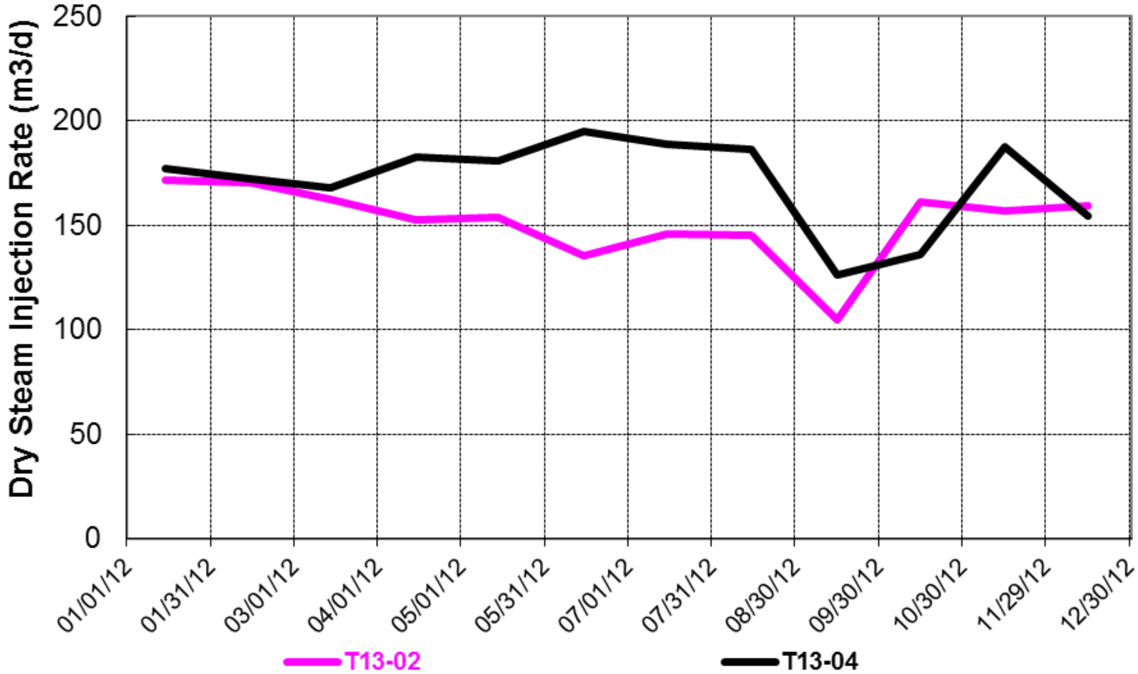
3.6 Spacing and pattern

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 * 650 m), which is roughly 24 acres per well.

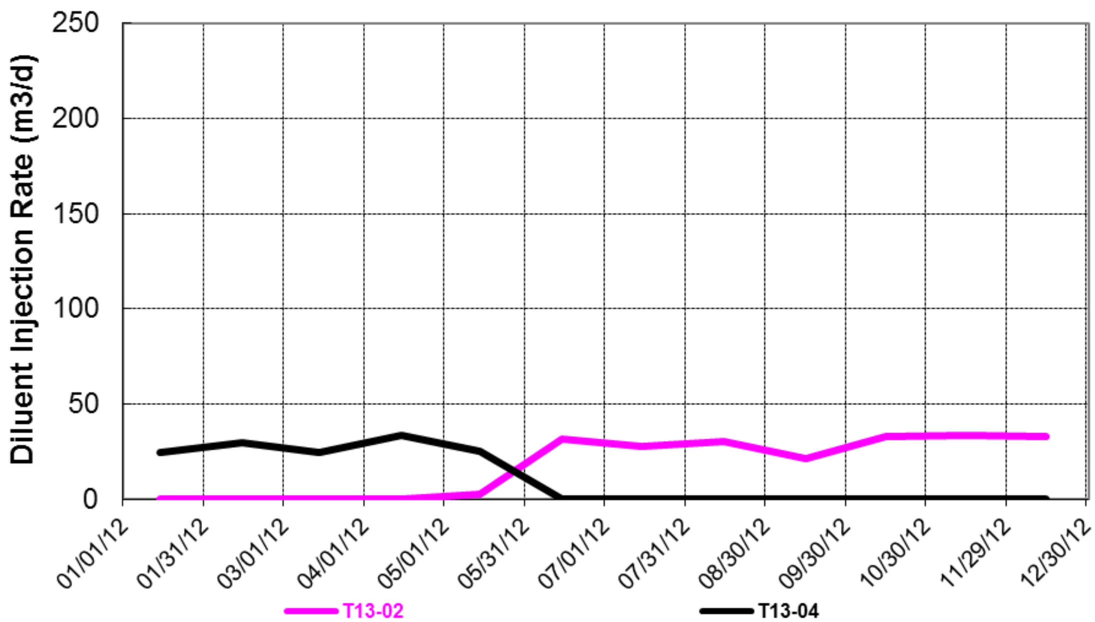
4 Production Performance

4.1 Injection and production history

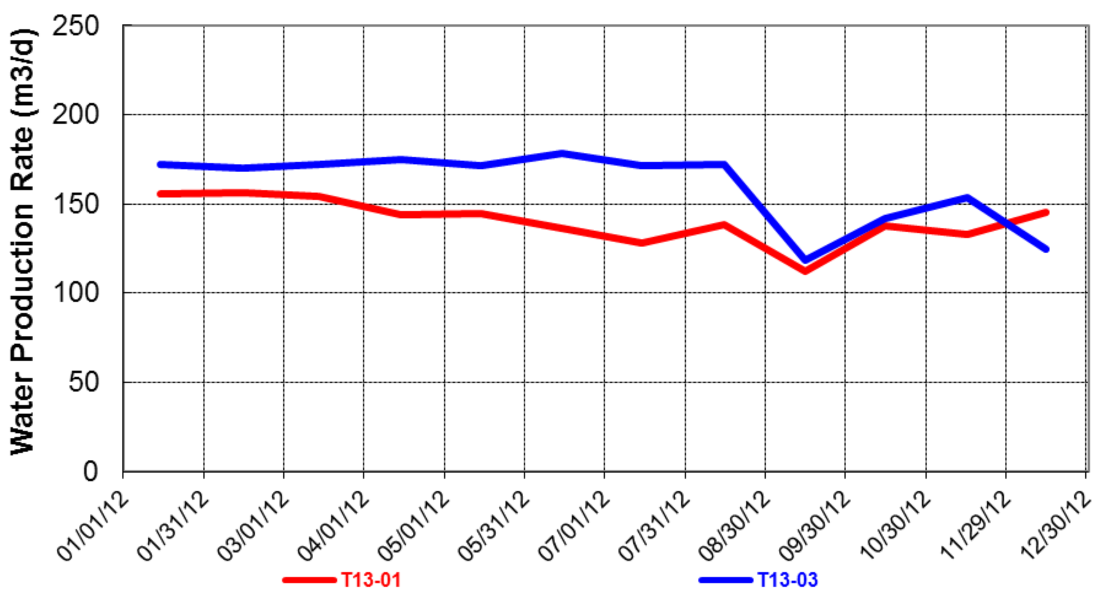
During SAGD / SA-SAGD operation, injection rates are dictated by an operational strategy to maintain injection pressure close to initial reservoir pressure (see section 4.4). Typical rates varied to achieve this, with durations of higher than average injection rates that followed periods of injection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



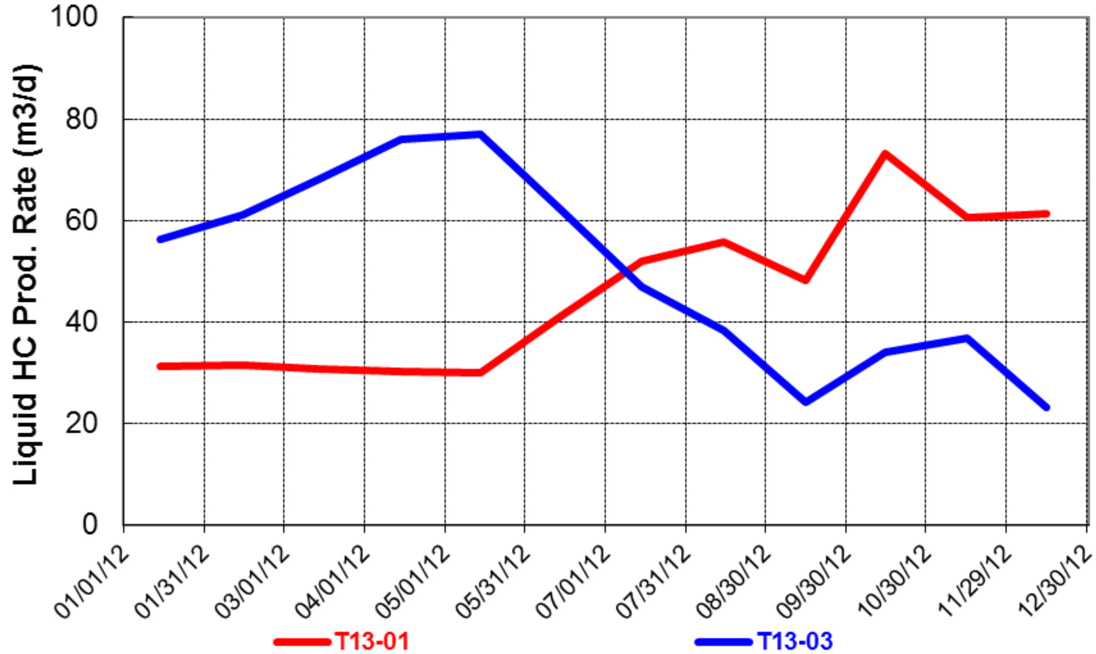
Well-pair 2 continued to operate in SA-SAGD mode until end of May 2012, when well-pair 1 started operating in SA-SAGD mode. Rates were dictated by a target diluent volume of roughly 20% volume diluent / volume steam. A plot of the monthly average diluent injection rates for each well is shown below.



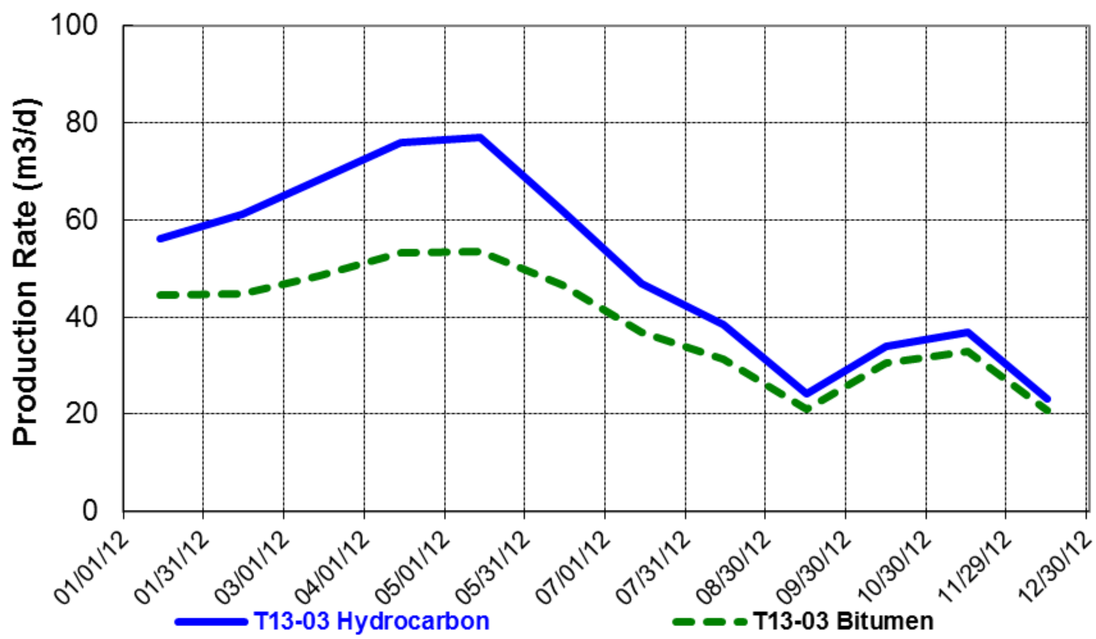
Water production during 2012 consisted of water from the condensing steam. Water production volumes from each well (monthly average rates) are shown below.

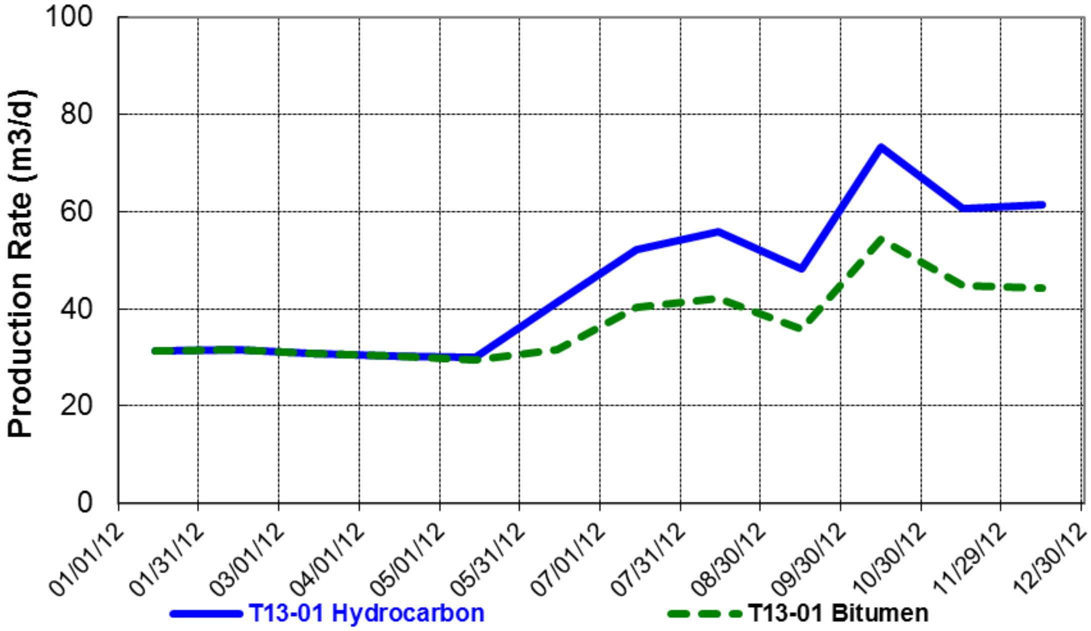


Liquid hydrocarbon volumes consisted of a bitumen plus recovered diluent mix. Liquid hydrocarbon production volumes from each well (monthly average rates) are shown below (including liquid hydrocarbon from both the liquid and vent gas separators).

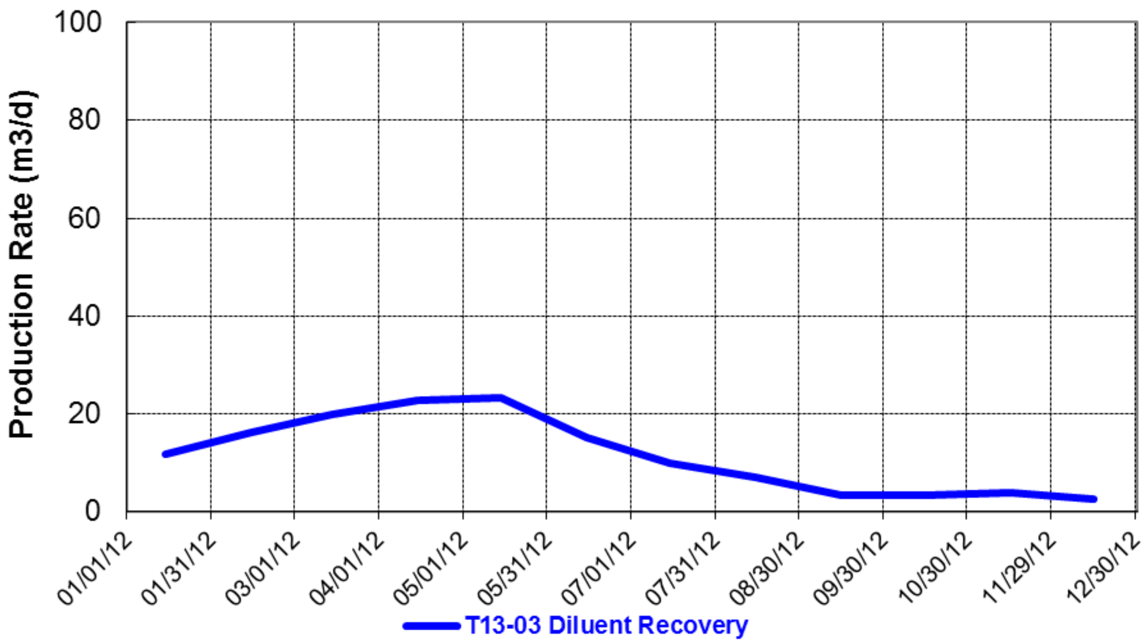


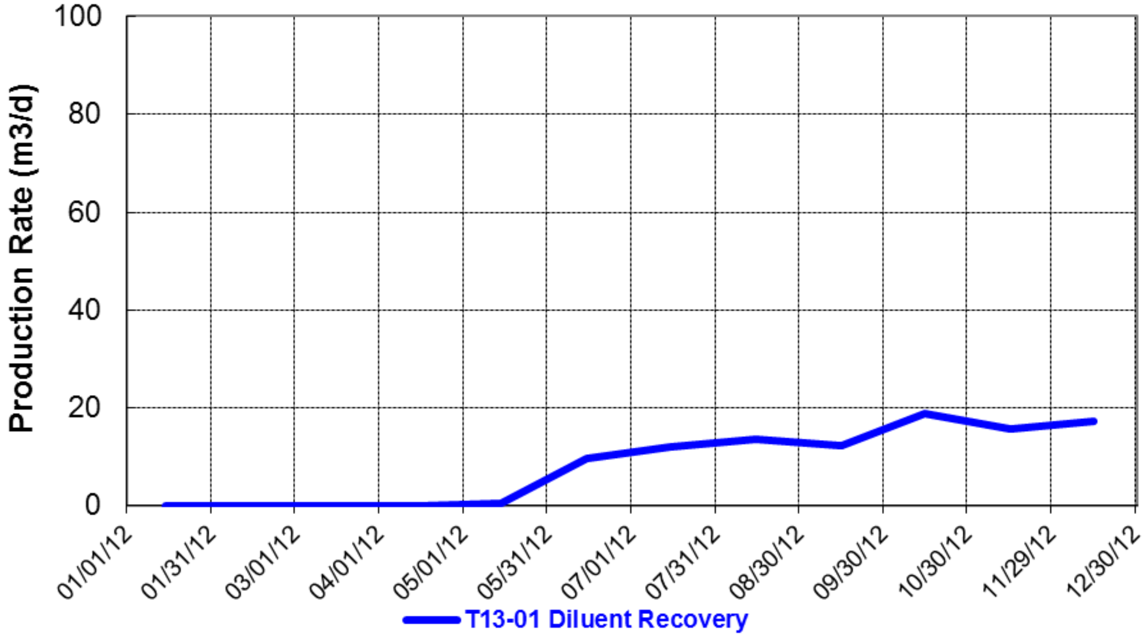
From production test samples, it was found during the year that 3 – 23 m^3/day of T13-03 and 10 – 19 m3/d of T13-01 hydrocarbon liquid volumes were recovered diluent. A breakdown of T13-03 and T13-01 hydrocarbon volumes to show bitumen production versus total hydrocarbon volumes (monthly average rates) are shown below.





Diluent recovery has also been measured after diluent injection commenced for each well pair. It was observed that roughly 30 - 80% of injected volumes were being recovered on a monthly basis. Total diluent recovery volumes (recovered from both the liquid and gas streams) from T13-03 and T13-01 (monthly average rates) are shown below.





100
80
60
40
20
0
Production Rate (m3/d)
01/01/12
01/31/12
03/01/12
04/01/12
05/01/12
05/31/12
07/01/12
07/31/12
08/30/12
09/30/12
10/30/12
11/29/12
12/30/12
T13-01 Diluent Recovery

4.2 Composition of produced / injected fluids

The components of the injected fluid consisted of dry steam and diluent. Injected diluent for the SA-SAGD well pair is sourced from Provident Midstream from its facility in Redwater, AB. The table below details a typical composition of the diluent.

COMPONENT	CARBON NUMBER	MOLE FRACTION	MASS FRACTION	LIQUID VOL FRACTION
Methane	C1	0.000	0.000	0.000
Ethane	C2	0.000	0.000	0.000
Propane	C3	0.000	0.000	0.000
i-Butane	i-C4	0.002	0.001	0.001
n-Butane	n-C4	0.040	0.029	0.033
i-Pentane	i-C5	0.250	0.224	0.238
n-Pentane	n-C5	0.264	0.236	0.248
Hexanes	C6	0.187	0.200	0.200
Heptanes	C7	0.080	0.099	0.095
Octanes	C8	0.030	0.043	0.041
Nonanes	C9	0.007	0.012	0.011
Decanes	C10	0.003	0.005	0.005
Undecanes	C11	0.001	0.002	0.002
Dodecanes	C12	0.001	0.001	0.001
Tridecanes	C13	0.001	0.001	0.001
Tetradecanes	C14	0.000	0.001	0.001
Pentadecanes	C15	0.000	0.001	0.001
Hexadecanes	C16	0.000	0.001	0.001
Heptadecanes	C17	0.000	0.001	0.001
Octadecanes	C18	0.000	0.001	0.001
Nonadecanes	C19	0.000	0.000	0.000
Eicosanes	C20	0.000	0.000	0.000
Heneicosanes	C21	0.000	0.000	0.000
Docosanes	C22	0.000	0.001	0.001
Tricosanes	C23	0.000	0.000	0.000
Tetracosanes	C24	0.000	0.000	0.000
Pentacosanes	C25	0.000	0.000	0.000
Hexacosanes	C26	0.000	0.000	0.000
Heptacosanes	C27	0.000	0.000	0.000
Octacosanes	C28	0.000	0.000	0.000
Nonacosanes	C29	0.000	0.000	0.000
Triacontanes Plus	C30 +	0.000	0.000	0.000
Benzene	C6H6	0.0085	0.0082	0.0062
Toluene	C7H8	0.0092	0.0105	0.008
Ethylbenzene, p + m-Xylene	C8H10	0.0049	0.0064	0.0049
o-Xylene	C8H10	0.0011	0.0015	0.0011
1, 2, 4 Trimethylbenzene	C9H12	0.0003	0.0004	0.0003
Cyclopentane	C5H10	0.0244	0.0212	0.0188
Methylcyclopentane	C6H12	0.0345	0.036	0.0318
Cyclohexane	C6H12	0.0238	0.0249	0.0211
Methylcyclohexane	C7H14	0.0266	0.0324	0.0278
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.

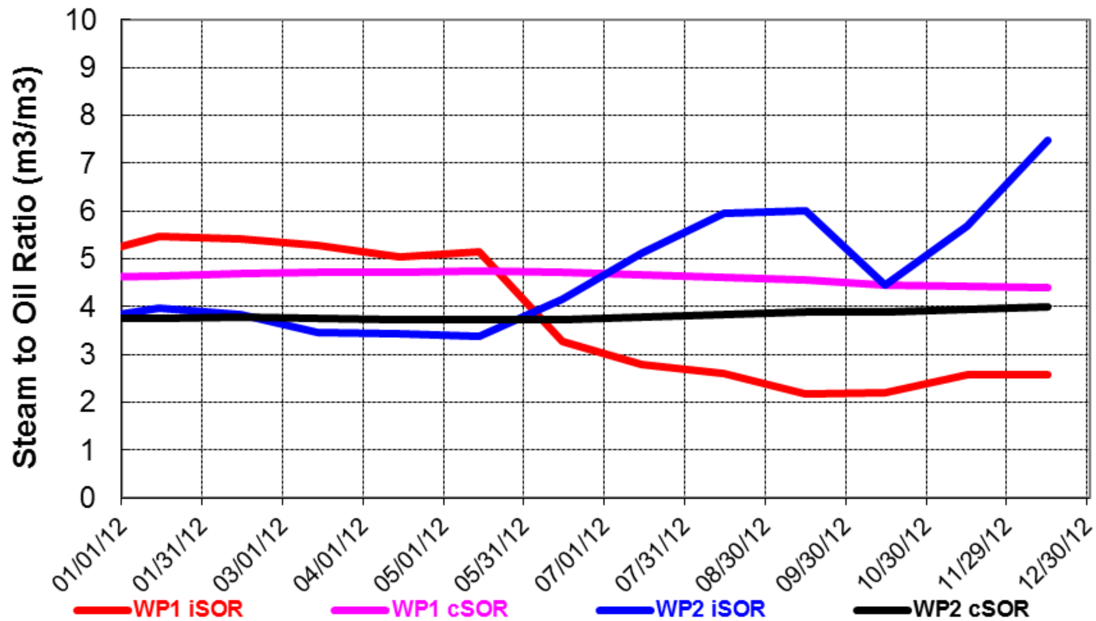
COMPONENT	CARBON NUMBER	MOLE FRACTION	MASS FRACTION	LIQUID VOL FRACTION
Methane	C1	0.0000	0.0000	0.0000
Ethane	C2	0.0000	0.0000	0.0000
Propane	C3	0.0000	0.0000	0.0000
i-Butane	i-C4	0.0000	0.0000	0.0000
n-Butane	n-C4	0.0000	0.0000	0.0000
i-Pentane	i-C5	0.0000	0.0000	0.0000
n-Pentane	n-C5	0.0000	0.0000	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

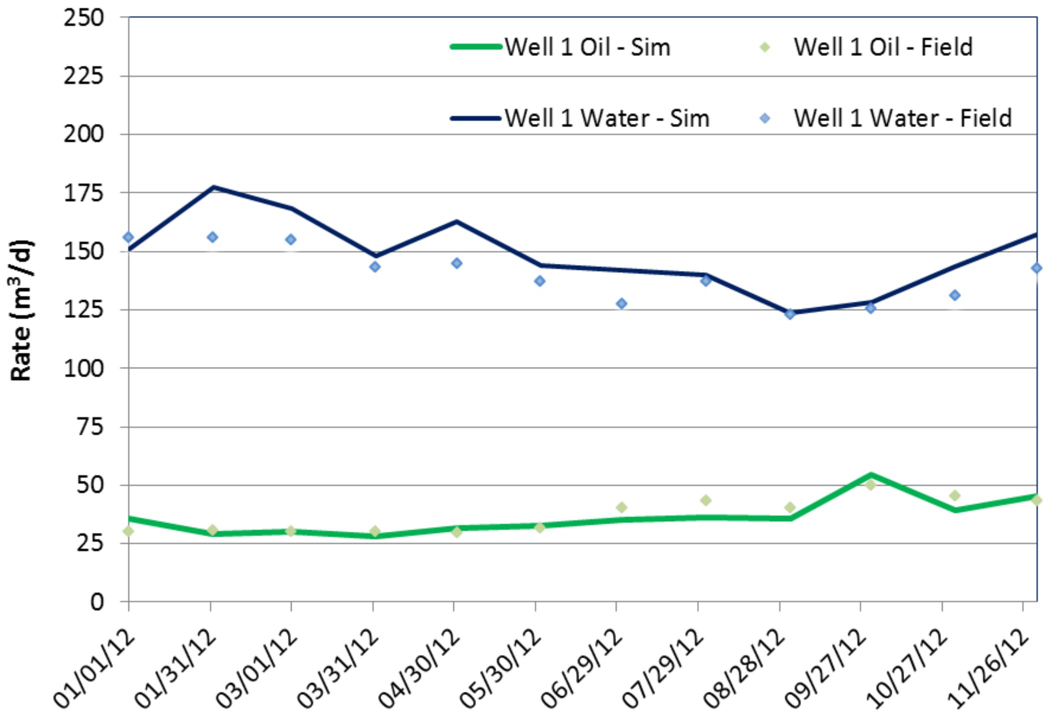
With the solvent switch occurring in May 2012, well-pair 1 transitioned from SAGD operations to SA-SAGD operations, and vice versa for well-pair 2. Well-pair 1 OSR went from 4-5 m^3/m^3 range (SAGD) to 3-4 m^3/m^3 range (SA-SAGD), and well-pair 2 went from 3-4 m^3/m^3 (SA-SAGD) to 5-7 m^3/m^3 (SAGD). In other words, actual SOR reduction was 25 to 30 %, compared to pre-pilot predictions of 15 to 30 %.

SORs continued to drop at well-pair 1 as oil rates increased due to the injection of diluent. At well-pair 2, SOR's continued to increase, due to cessation of diluent injection, as well as plugging issues observed at the producer. This plugging (skin) caused the producer BHP to decrease, the pump to operate inefficiently, and production fluid rates to drop (see section 10.1 for further discussion on skin).

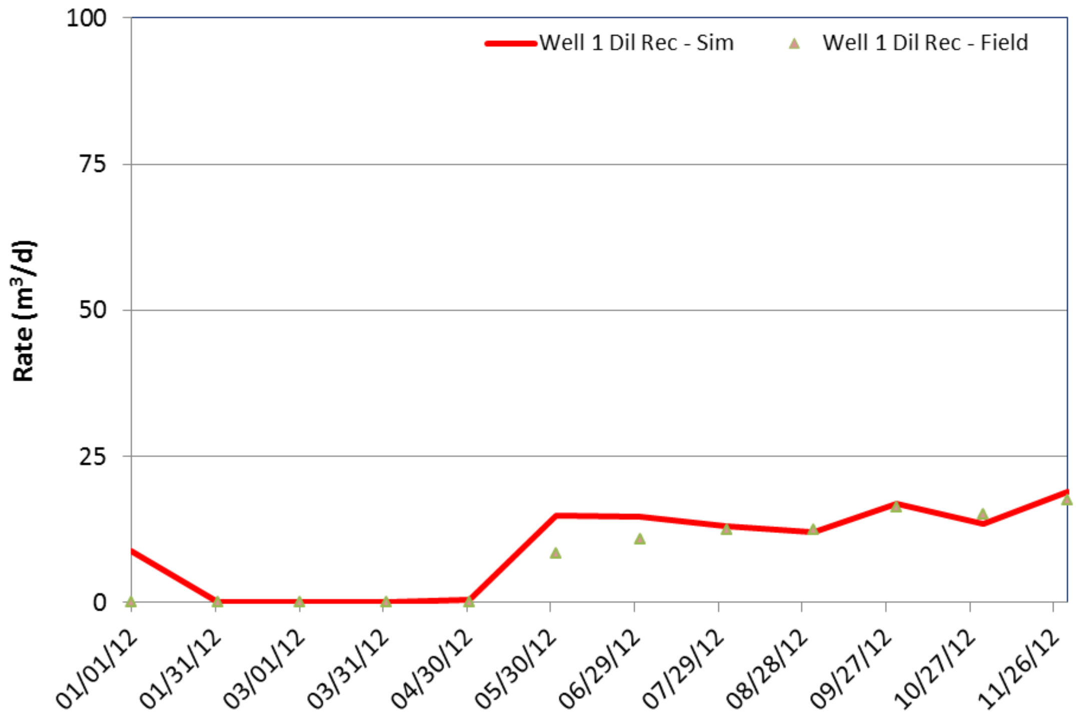
SORs seen to end of 2012 are generally within the expected performance range, with the exception of the increase in SOR on well-pair 2 due to skin issues. Plots of instantaneous and cumulative SORs (monthly averages) for each well-pair are shown below.



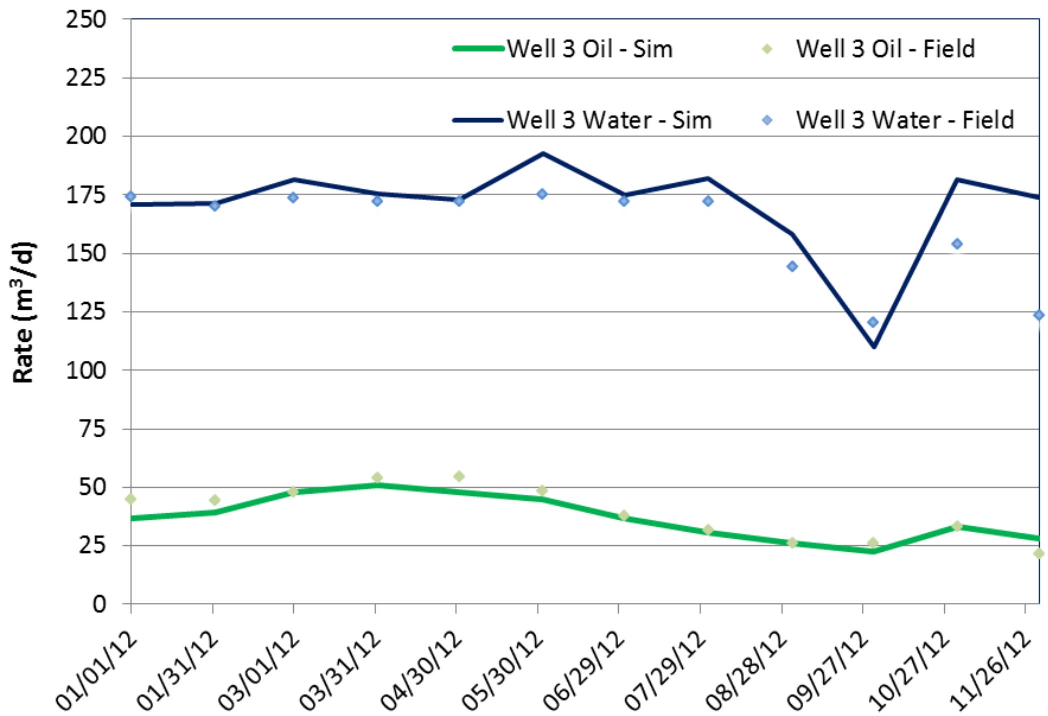
Field data was also used to generate history matched geologic-model based simulation models for SAGD / SA-SAGD operation, and create go forward predictions. Using steam injection volumes and production pressures as inputted values, oil and water production rates were history matched. At the time of the solvent switch, bitumen uplift was between 40 to 60 %, compared to initial pre-pilot predictions of 5 to 40 %. In terms of solvent recovery, well-pair 2 (SA-SAGD until May 2012, then SAGD) achieved a 78 % solvent recovery by the end of 2012 (and continued to increase), and pre-pilot predictions of recovery were in the range of 65 to 80 %.



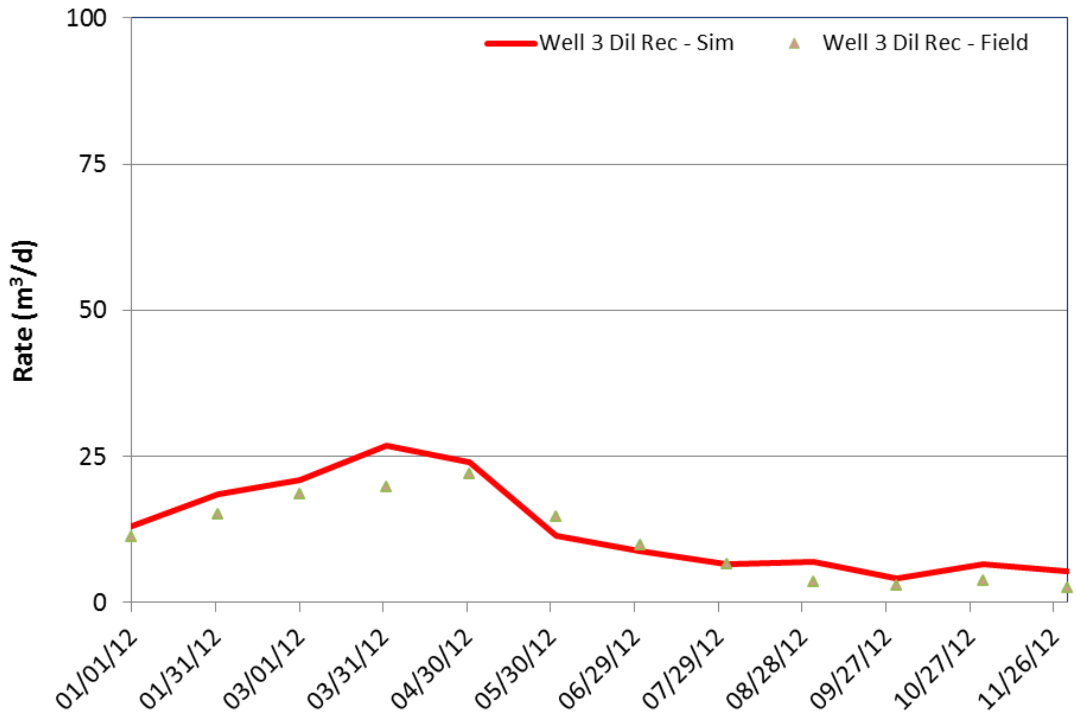
The plot below shows diluent production, field data compared to latest simulation model results. Diluent production at well 1 began in May 2012 (after solvent switch), and model matches field data, in terms of timing and magnitude, fairly well.



The plot below shows a comparison of field data with latest simulation model results (history match) of well 3 (well-pair 2 producer) 2012 performance. Both field and simulation model show a decrease in oil rates after cessation of solvent injection in well 3 in May 2012, the simulation model captures the timing and rate of decrease quite well. Water match generally tracks field water production at well 3, however, it deviates slightly from field after the Sept/Oct shut in. Another important phenomenon that was observed in the field is the development of skin around the producers. This phenomenon was successfully captured in the simulation model with a proper skin model.



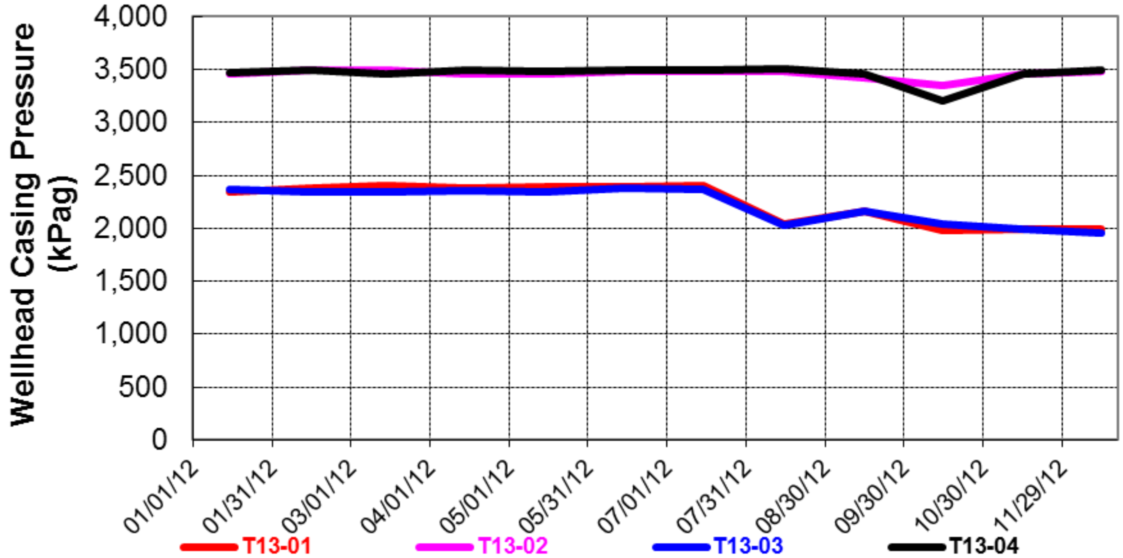
The plot below shows diluent production, field data compared to latest simulation model results. Diluent production at well 3 began to decline in May 2012 (after solvent switch), and model matches field data, in terms of timing and magnitude, fairly well.



Saturation logs were taken in 2012 as part of a special surveillance program, and a discussion of the results is covered in section 5.2.

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 2,000 – 2,500 kPa range (wells T13-01 and T13-03). During the September/October injection shut in, wellhead pressure in the injection wells declined to approximately 3,000 kPa for a few days. Plots of casing wellhead pressures (monthly average) for each well are shown below.

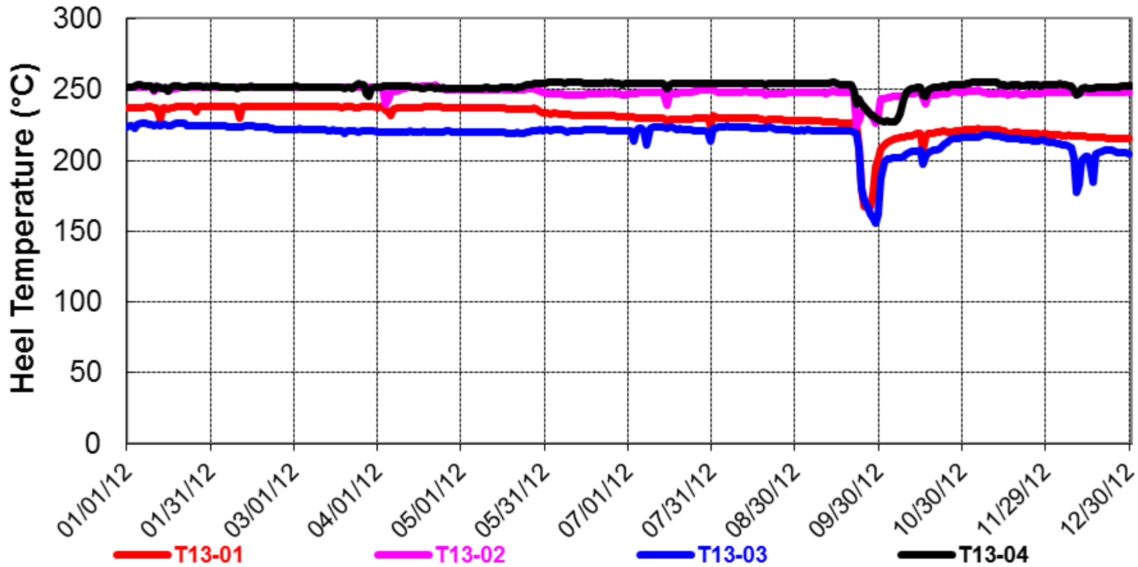


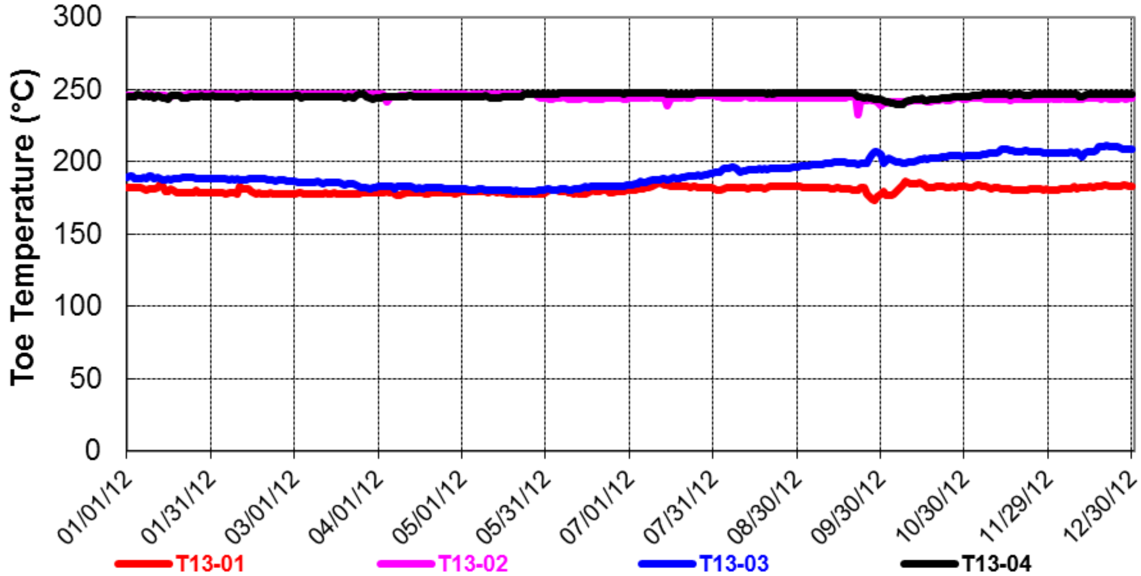
5 Pilot Data

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.

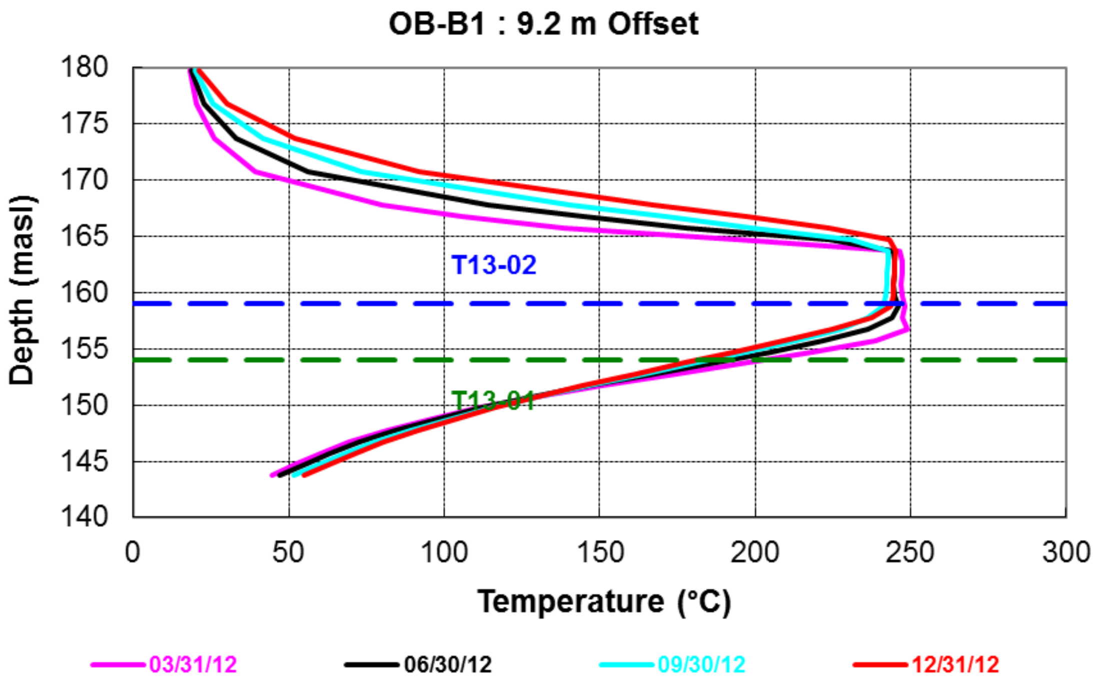
Injector well temperatures were approximately 245-250°C during SAGD/SA-SAGD operation (heel and toe of T13-02 & T13-04). Temperatures on the producer wells (T13-01 & T13-03) varied from 155 – 240 °C along the wells during SAGD/SA-SAGD operation. Temperatures (daily average) along the horizontal well at the heel and toe wells are shown below.

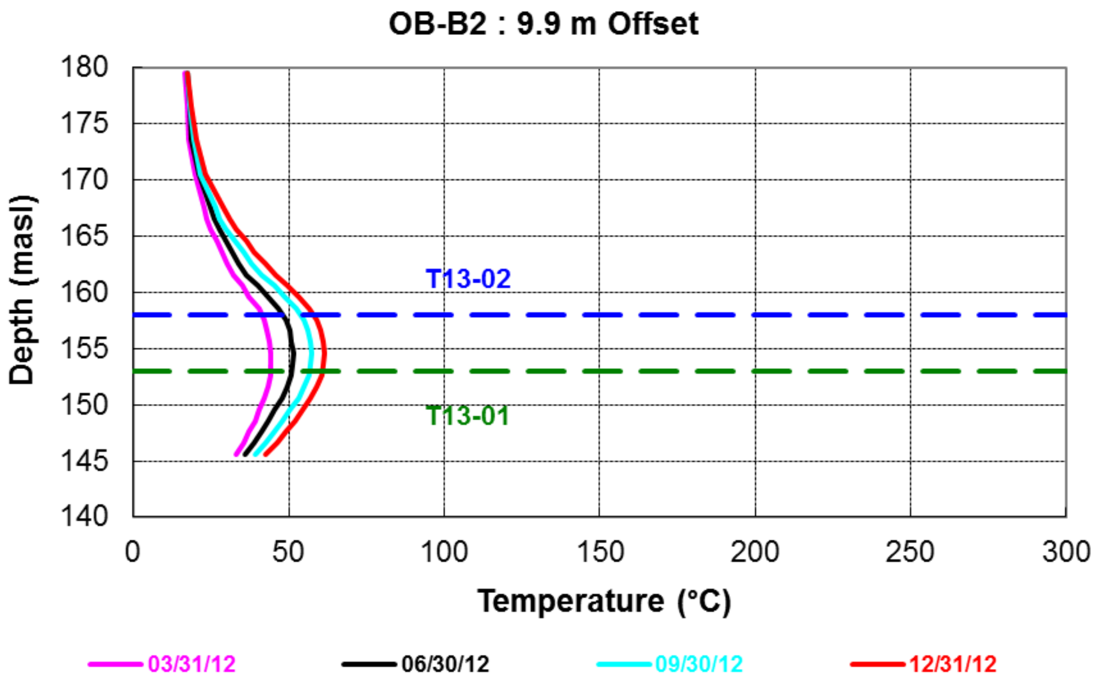


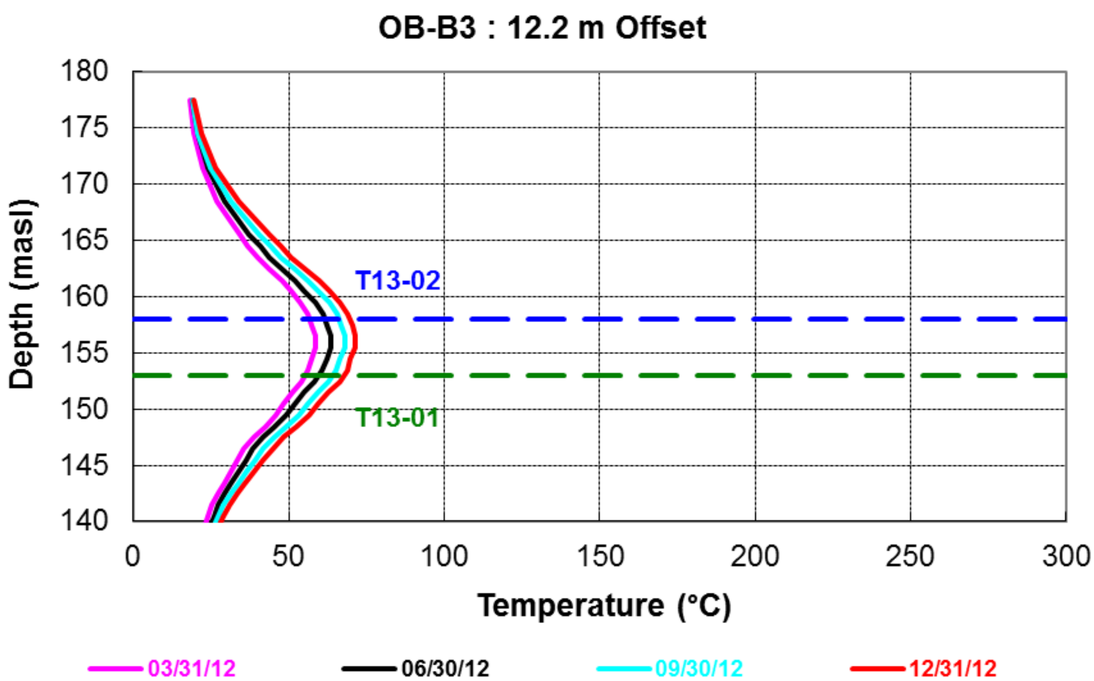


There are six total observation wells, three for each well-pair, that are positioned at the toe, heel, and midpoint of each horizontal well-pair. The offset distance from the horizontal wells varies between 5.7 and 13. 5 m. The temperature at the observation wells provides a measure of the amount of heat transferred to the reservoir.

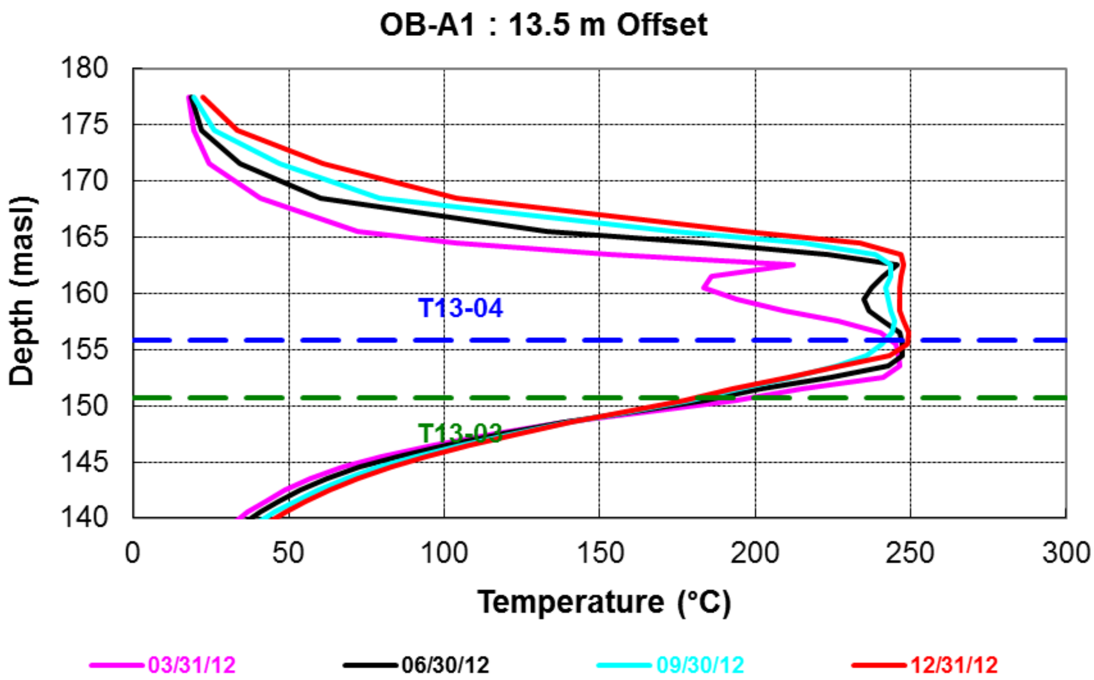
Observation wells OB-B1, B2, and B3 are adjacent to heel, mid, and toe of well-pair 1 (T13-01 & T13-02). Steam temperature was reached on OB-B1 in 2010, with continued vertical growth observed in 2011 and 2012. Temperature responses of between 60 – 70°C were also observed on B2 & B3 by the end of 2012. The temperature as a function of depth is shown below for each observation well at three-month intervals (dashed lines represent approximate depths of both the injector and producer wells from the adjacent well-pair).

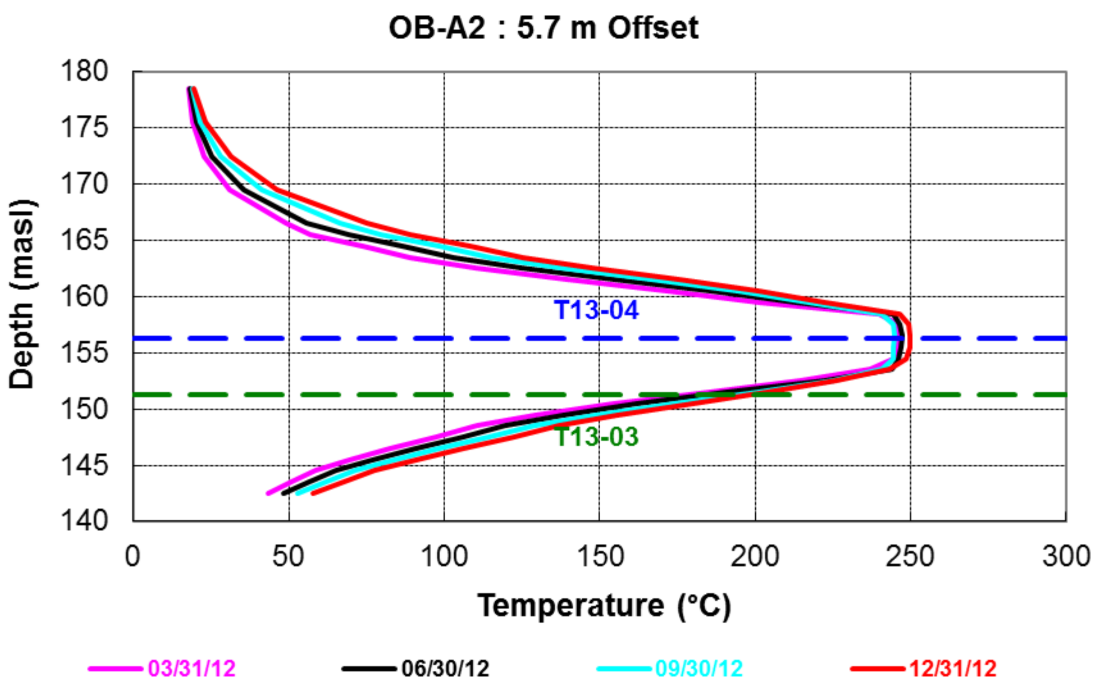


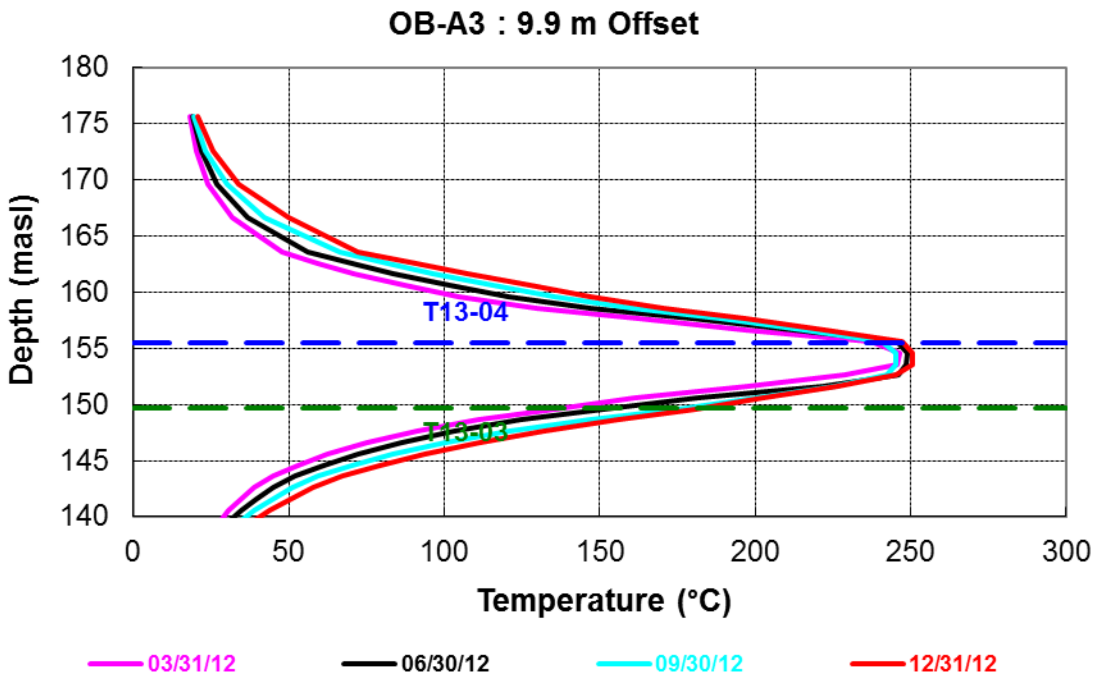

OB-B2 : 9.9 m Offset
Depth (masl)
180
175
170
165
160
155
150
145
140
T13-02
T13-01
0
50
100
150
200
250
300
Temperature (°C)
03/31/12
06/30/12
09/30/12
12/31/12


OB-B3 : 12.2 m Offset
Depth (masl)
180
175
170
165
160
155
150
145
140
T13-02
T13-01
0
50
100
150
200
250
300
Temperature (°C)
03/31/12
06/30/12
09/30/12
12/31/12

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 2012. The temperature as a function of depth is shown below for each observation well at three-month intervals (dashed lines represent approximate depths of both the injector and producer wells from the adjacent well-pair).





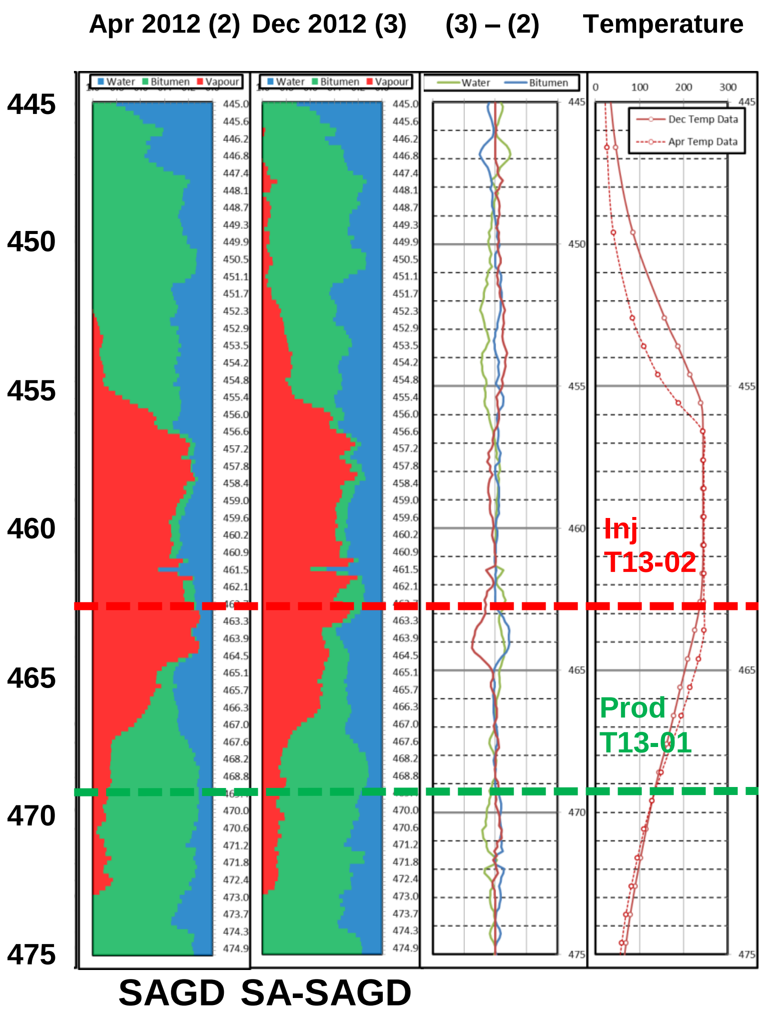


OB-A3 : 9.9 m Offset
180
175
170
165
160
155
150
145
140
Depth (masl)
T13-04
T13-03
0
50
100
150
200
250
300
Temperature (°C)
03/31/12
06/30/12
09/30/12
12/31/12

5.2 Interpretation of pilot data

The solvent switch in May 2012 provided valuable insight into understanding the SA-SAGD process, and performance uplifts associated with this process. When diluent injection ceased in well-pair 2, bitumen rates dropped by 60% and SOR increased by 25-30 %, and conversely, when diluent injection began at well-pair 1, bitumen rates increased by 40-50%, and SOR decreased by 25-30%. These results confirm the work performed by the Alberta Research Council (ARC)[2] and by Imperial which 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.

All six OB wells had baseline cased-hole saturation logs run prior to the start-up of steaming operations at T13. Subsequent logs were run in 2012 to evaluate the development of the steam chambers in these wells and to assess the differential performance of SAGD versus SA-SAGD performance. The figure below is an example of the results from this logging program for OB-B1. In general, the vapor saturated intervals in these repeat saturation logs were consistent with the thermocouple temperature profiles and showed low residual-bitumen saturations for both SAGD and SA-SAGD operations.



[2] 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.

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 2012 10-K filing
- Solvent pricing from the Sproule December 31, 2012 price database

	Bitumen C$/bbl	Solvent (Edmonton Pentanes Plus) C$/bbl	Natural Gas C$/mcf
2010	58.36	84.21	4.04
2011	63.95	104.12	3.59
2012	59.76	100.84	2.33

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 was **77,795 m^3** in 2012.

Steam injection was 118,158.1 m^3 in 2012. Based on a 75 m^3 natural gas / m^3 steam ratio to generate steam, it is estimated that **8,861,858 m^3** of natural gas was required to generate steam volumes

Thus, the net gas volume for 2012 was **-8,784,063 m^3** (77,795 m^3 – 8,861,858 m^3).

6.2 Revenue

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.

Gross revenue for the pilot in 2012 is estimated to be **C$ 10,439,665**. This is based on a bitumen production volume of 27,774 m^3, and a bitumen price of 59.76 C$/bbl.

6.3 Capital costs

The following table summarizes capital costs by category, incurred in 2012 (as per 2012 IETP claim form submissions):

Category	Description and Details of Capital Costs	Cost (C$)
Facilities	Drilling	0.00
	Surface Facilities (Steam injection facilities, separator; chemical injection facilities, separator; production facilities, pump jacks, ROV, coolers)	0.00
	Engineering Procurement Construction	0.00
	Trunkline / Laterals	0.00
	Facilities - Capital Related Expense	0.00
Drilling	Drilling four horizontal wells - 2 well pairs, each wellpair consist of an injector and producer well.	0.00
	Completion of horizontal wells	0.00
	Capital Related Expense	0.00
Trunkline	Drilling	0.00
	Surface Facilities	0.00
	Engineering Procurement Construction	0.00
	Trunkline / Laterals	0.00
	Capital Related Expense	-6,370.92
Total Capital Costs (C$)		**-6,370.92**

The capital costs for 2012 are negative because of an AFE that was reopened for a Material and Equipment Transfer, which indicates that material/equipment that was originally charged to the AFE was in fact transferred to another location.

6.4 Direct and indirect operating costs

The following table summarizes operating costs by category, incurred in 2012 (as per 2012 IETP claim form submissions):

Category	Description and Details of Operating Costs	Cost (C$)
Facility Exp.	Drilling observation wells, well heads, completions, reservoir monitoring instrumentation	0.00
	Completions	0.00
	Surface Facilities (Facilities portion associated with solvent injection: solvent tank, pump, lines; production and vent gas testing equipment, samples, separators, horizontal well reservoir monitoring instrumentation; EPCM)	0.00
Field Exp.	Field operating costs	959,977.14
	Surveillance costs	1,396,777.75
Total Operating Costs (C$)		**2,356,754.89**

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 in 2012 were (as per 2012 IETP claim form submissions):

Total Injectant Costs (C$)	**7,437,695.53**

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 three years.

(C$)	2005	2006	2007	2008	2009	2010	2011	2012	Total ('05-'12)
SA-SAGD Revenue	0	0	0	0	0	5,216,789	16,450,837	15,073,158	**36,740,784**
SA-SAGD CAPEX & OPEX	1,484,356	1,442,184	1,661,186	20,463,138	12,569,963	3,152,997	6,815,711	9,788,080	**57,377,614**
SA-SAGD Gas Expense	0	0	0	0	52,724	786,251	958,678	722,781	**2,520,434**
SA-SAGD Cash Flow	(1,484,356)	(1,442,184)	(1,661,186)	(20,463,138)	(12,622,687)	1,277,541	8,676,449	4,562,298	**(23,157,263)**
Cold Lake Royalty Rate	30%	30%	30%	25%	28%	31%	34%	34%	
Cold Lake Royalty Impact	(445,307)	(432,655)	(498,356)	(5,115,785)	(3,510,369)	395,006	2,935,577	1,543,601	**(5,128,288)**
Total Cold Lake Payable Royalties	**157,264,756**	**375,655,398**	**338,663,276**	**575,819,711**	**438,161,793**	**628,311,434**	**934,732,007**	**680,330,734**	**4,128,939,109**

[1] Estimated, see section 6.6 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] Total Cold Lake royalties paid, which include SA-SAGD costs and revenue. IETP credits are not included.
[5] Amendments to prior years were processed, therefore the royalties for these years has been revised since the 2011 annual IETP progress report

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 & shipping, but for the purposes of this report, solvent recovery is shown as a theoretical revenue stream. Estimates have been made for:

Bitumen revenue in 2012 = C$ 10,439,665 (see section 6.2)
Recovered solvent revenue in 2012 = C$ 4,633,493 (based on a recovered volume of 7,305 m^3, and a solvent price of 100.84 C$/bbl)
Net natural gas expense in 2012 = C$ 722,781 (see section 6.1 - based on a net gas volumes of -8,784,063 m^3 and a gas price of 2.33 C$/mcf)

Capital and operating costs are known to be:

Capital costs in 2012 = C$ -6,371 (see section 6.3)
Operating costs in 2012 = C$ 9,794,450 (see section 6.4 – includes operating and injectant costs)

2012 cash flow is estimated to be:

Cash Flow = Revenue – Costs – Royalties
= (Bitumen + Solvent Revenue) – (Capital + Net Gas + Operating Costs) – Royalties
= (10,439,665 + 4,633,493) – (-6,371 + 722,781 + 9,794,450) – 1,543,601
= C$ 3,018,697

This does not include taxes.

6.7 Cumulative project costs and net revenue

Cumulative project costs to date are:

C$	Up to YE 2010	2011	2012	Total (to YE 2012)
Total Capital Costs	26,133,883	78,212	-6,371	**26,205,724**
Total Operating Costs	13,828,517	1,048,829	2,356,755	**17,234,100**
Total Injectant Costs	811,423	5,688,670	7,437,696	**13,937,789**
Total Net Gas Costs[1]	838,975	958,678	722,781	**2,520,433**
Total Costs	**41,612,798**	**7,774,389**	**10,510,860**	**59,898,046**

[1] Estimated, see section 6.6 for assumptions

Cumulative project revenue to date is:

C$	Up to YE 2010	2011	2012	Total (to YE 2012)
Bitumen Revenue	4,898,707	12,877,231	10,439,665	**28,215,602**
Solvent Revenue	318,082	3,573,606	4,633,493	**8,525,182**
Total Revenue	**5,216,789**	**16,450,837**	**15,073,158**	**36,740,784**

[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 (~83m^3 of useable volume)
- Diluent pump

Production side

- Rotary operated valve to direct production either to test or 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 in 2012.

7.3 Process flow and site diagrams

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

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 (IOR 2012) 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 73534-0-04, as amended.

9 Future Operating Plan

9.1 Project schedule

Key future milestones would be as follows:

▪ 2012 Progress Report	Q2, 2013
▪ End of Pilot Operations	Q4, 2013
▪ Final Report Issued	Q2, 2014

Key deliverables from the project team and the pilot operating team would be as follows:

- Monthly reporting of injection and production volumes to ERCB (held confidential until end of pilot period)
- Annual progress reports (ERCB confidential) would only document operations data and the ongoing analysis of pilot performance including plots of cumulative injection, production, steam-oil ratios and solvent recovery from each well pair; plots of temperature profiles from the observation wells; and data from any surveillance tools such as 3D seismic or cased hole logging
- Final report to include an engineering analysis of pilot performance versus key pilot objectives including output from reservoir simulation tools tuned to history match observed pilot performance

9.2 Changes in pilot operation

Our team is considering a second solvent switch in 2013 before end of pilot operations.

9.3 Optimization strategies

As our pilot producers began to develop skin, which in turn impacted the wells' inflow capabilities, and thus, total fluid production (see section 10.1 for further details), our team:

(a) completed an acid job on T13-03 and T13-01 in Q1 2013 to remove skin
(b) plans to complete a second acid job on T13-03 in 2013, as skin has developed around the well once more, and an intervention is warranted

9.4 Salvage update

Currently, there are no plans to salvage any of the equipment on site.

10 Interpretations and Conclusions

10.1 Overall performance assessment

To summarize overall 2012 performance:

- Well-pairs went through a solvent switch in May 2012, solvent response apparent
- Continued successful pilot operations in 2012
- SAGD (well-pair 1) and SA-SAGD (well-pair 2) performance to date was generally within the expected range, encountering skin issues enhanced learning, and predictions were adjusted accordingly

Difficulties Encountered

Well-pair 2 has experienced an increasing near-wellbore pressure drop in T13-03. For much of the pilot period, this pressure drop did not interfere with the operations of well-pair 2 as the FBHP was higher than the surface separator pressure, ensuring that a fluid column was maintained above the pump. However, during the latter part of 2012 the FBHP declined to the point where this fluid column could not be sustained and gas interference effects became apparent. These effects complicate interpretation of the post solvent-switch production decline for well-pair 2.

Technical and Economic Viability

Judgements regarding technical and economic viability of a solvent-assisted SAGD process have yet to be made at this time.

Overall Effect on Gas / Bitumen Recovery

This has yet to be determined.

Future expansion or commercial field application

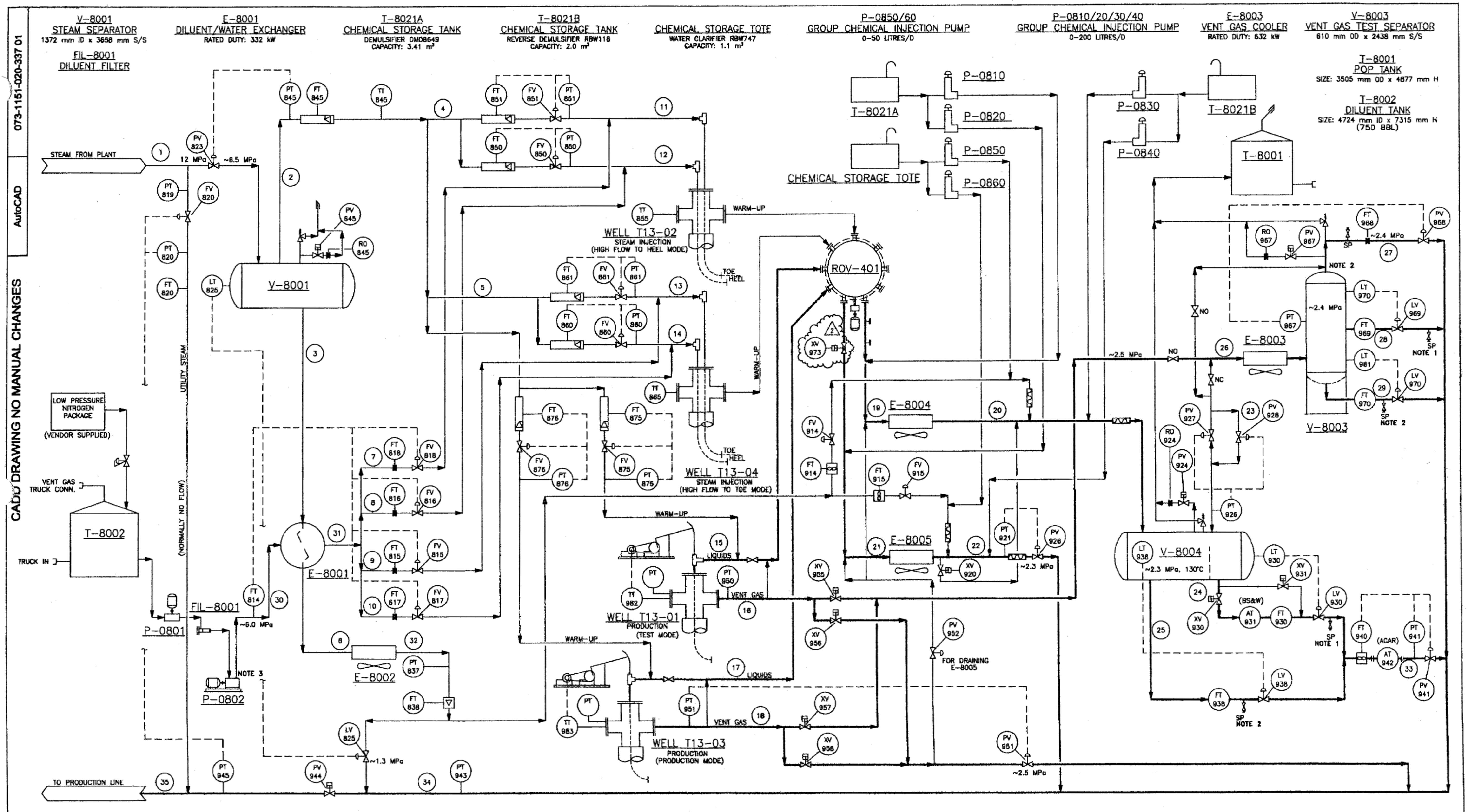
This has yet to be determined.

Appendix A

Process Flow Diagrams (PFDs)

&

Site Maps



CONSTRUCTION NOTES:

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

P-0801 DILUENT BOOSTER PUMP 66 m³/d	P-0802 DILUENT INJECTION PUMP 66 m³/d	E-8002 WATER COOLER RATED DUTY: 3498 kW	E-8004 PRODUCTION TEST COOLER RATED DUTY: 1285 kW	E-8005 PRODUCTION COOLER RATED DUTY: 1285 kW	ROV-401 8-WAY ROTARY SELECTOR VALVE	V-8004 PRODUCTION TEST SEPARATOR 1524 mm ID x 6706 mm S/S

Imperial Oil

Esso

IMPERIAL OIL RESOURCES

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

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

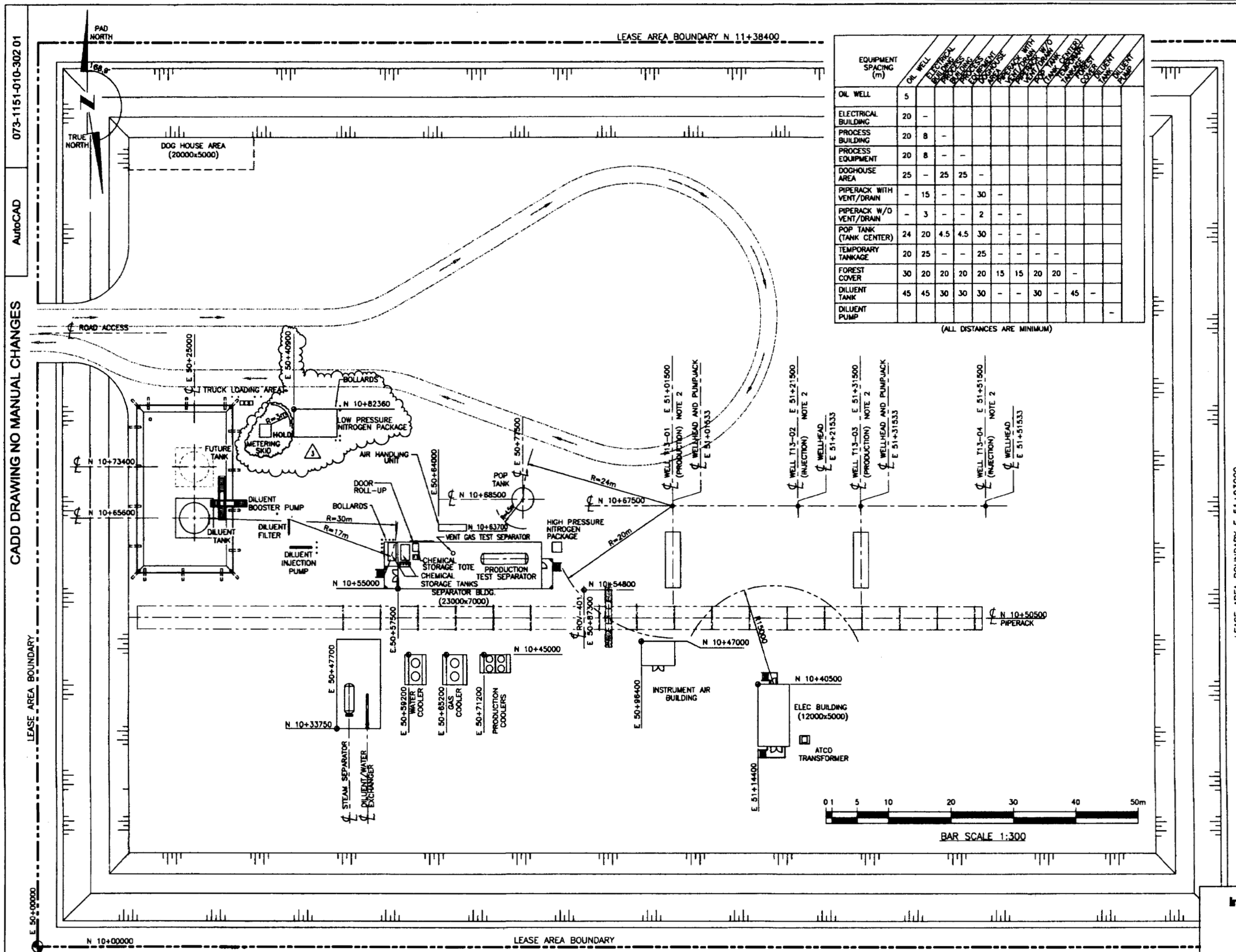
SEAL/STAMP

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

APPROVED FOR CONSTRUCTION
DATE Mar 26/09 REV. 2
PROJECT ENGINEERING

CONTRACTOR NAME	SCALE	IOR DRAWING NUMBER	REV.
COLT ENGINEERING CORPORATION	NONE	073-1151-020-337 01	2
CONTRACTOR DWG NUMBER XY.2006.28284			

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.

NO.	DATE	REVISIONS	DRAWN	CHECK	DESIGN	APPR.
3	09 05 25	RE-ISSUED FOR CONSTRUCTION - MOC C-4784 (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			
CONTRACTOR DWG NUMBER XY.2008.28284	1:300	073-1151-010-302 01	3

073-1151-010-302 01

AutoCAD

CADD DRAWING NO MANUAL CHANGES