surmont
PROJECT

Surmont SAGD Pilot Project
Resource Management Report

Period January 1 to December 31, 2004

Prepared by ConocoPhillips Canada

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INTRODUCTION

The Alberta Energy and Utilities Board required as part of Decision 2000-22 that ConocoPhillips Canada (formerly Gulf Canada Resources Limited) submit annual reports on the management of the resources on its Surmont leases, including the continued assessment on the effect of the pressure of the overlying gas zone on SAGD bitumen recovery. The requirements for the annual Resource Management Report (RMR) were clarified in a letter dated May 9, 2001. This section of the report deals with the pilot scheme results for the year 2004.

The operating strategy for 2004 was to increase the pressures in A (P1/S1) and B (P2/S2) in an attempt to continue steam chamber growth and monitor steam chamber development as a function of pressure. As such, it was necessary to restrict production during this time to assist the pressure development. This restriction and increased steam injection caused the cumulative SOR to climb to 3.2 by the end of the year, compared to less than 3.0 in the past. Well pairs A and B were operated at the same pressure since it was believed their associated steam chambers could be interacting.

Gradually increasing the operating pressures at the A and B well pairs starting in September 2003 and continuing during most of 2004, resulted in observation wells OB 41 and OB 36 at the A well pair recording the presence of a steam chamber throughout 2004 and OB 22 at the B well pair exhibiting a good steam rise rate again. All excess steam was diverted to the C (S3/P3) well pair to keep the well pair warm. As more steam became available steam injection was increased at the C well pair and resulted in observation well OB 20 recording the presence of a steam for the first time and OB 37 recording the presence of steam once again.

The average bitumen production from A and B well pairs was 60 m^3/d. This rate is reasonable given that the operating pressure was building for most of the year. Production from the C well pair was shut-in in November 2003 when the gas lift system could no longer function at lower reservoir pressures, and remained shut-in until October 2004, when a rod pump was installed.

To date the pilot has shown that mudstones interbeds behave as baffles to steam and that steam development and rise rates are mostly influenced by geology at the wellbore level, completion and operational constraints and steam chamber pressure variations. Observation well data has demonstrated that hydraulic pressure communication between the SAGD steam chambers and the thief zones is occurring. To date no negative impacts to bitumen production has been detected. The growth rate of the steam chamber has largely been dependent on operational processes.

ConocoPhillips continues to follow plans at the pilot project to test and confirm its ability to operate SAGD commercially upon contact by the steam chamber with a pronounced overlying thief zone. This is important in order to meet the goal of exploiting thick, rich bitumen overlain by thick water and/or gas found in the rest of the lease. Exploitation of these reserves is expected after initial stages of commercial development that are oriented towards areas of relatively low risk of top water.

1 DRILLING AND COMPLETIONS

1.1 Well Layout

The pilot project consists of three horizontal SAGD well pairs drilled in a northeast to southwest direction with all six wellheads located in LSD 14-24-83-7 W4M as follows:

- Well pair A: center well pair - production well P1; steam injection well S1; 350 m horizontal section terminates in LSD 5-24-83-7 W4M.
- Well pair B: northern well pair - production well P2; steam injection well S2; 350 m horizontal section terminates in LSD 12-24-83-7 W4M.
- Well pair C: new southern well pair - production well P3; steam injection well S3; 700 m horizontal section terminates in LSD 4-24-83-7 W4M.

The true vertical depth of the horizontal section of A well pair's production well P1 is at an elevation of 217.0 m (+/- 1.0 m) ASL. The corresponding S1 steam injection well is located 5.0 m (+/- 1.0 m) vertically above the P1 production well.

The true vertical depth of the horizontal section of B well pair's production well P2 is at an elevation of 221.0 m (+/- 1.0 m) ASL. The corresponding S2 steam injection well is located 5.0 m (+/- 1.0 m) vertically above the P2 production well.

The true vertical depth of the horizontal section of C well pair's production well P3 is at an elevation of m 227 m (+/- 1.0 m) ASL. The corresponding S3 steam injection well is located 5.0 m (+/- 1.0 m) vertically above the P3 production well.

There are four (4) observations wells located along the A well pair, two (2) along the B well pair and five (5) along the C well pair. There is also an observation well located between the A and C well pairs and a well between A and B well pair. Most of these wells either have thermocouples strings, piezometers or both thermocouple strings and piezometers installed in them. The following figures illustrate their locations and the instrumentation configurations.

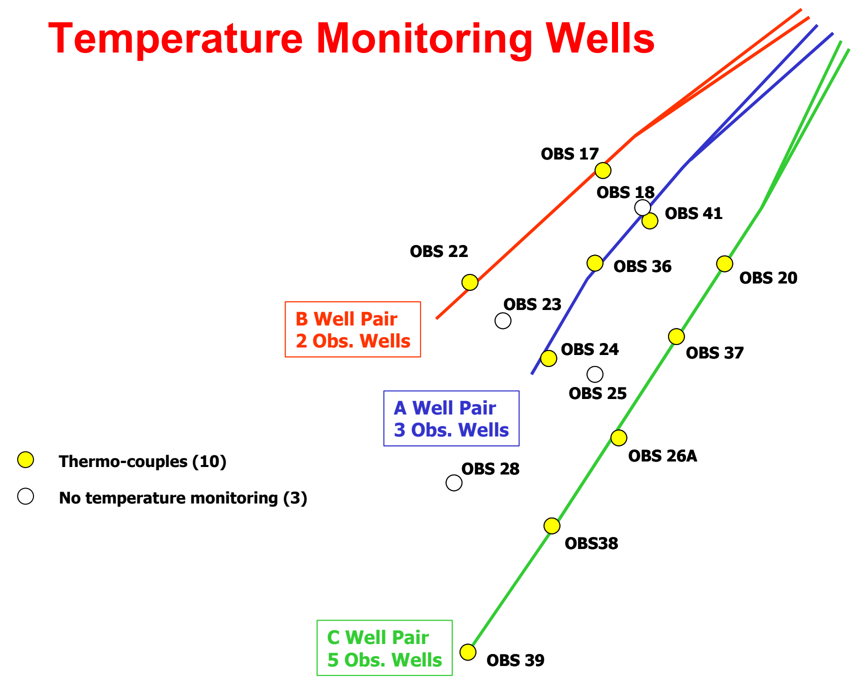


Figure 1.1.1 - Temperature Monitoring Wells

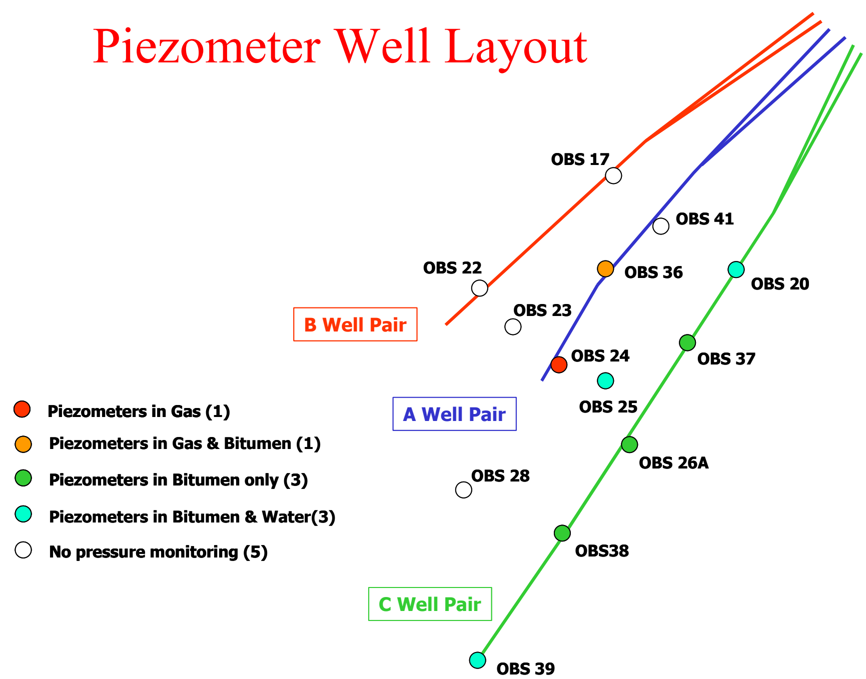


Figure 1.1.2 - Piezometer Well Layout

1.2 Drilling Experience

There were no drilling activities directly associated with the pilot during 2004.

1.3 Well Completions and Workovers

1.3.1 P1 (107/05-24-83-07W4M)

In May 2004, the existing 4.75" tubing barrel pump failed due to normal wear. It had been running since November 2002. A replacement 4.75" pump was installed along with the existing Ecoquip surface hydraulic unit. This pump failed a month later in June as the cage had fallen off due to improper torque make up. Subsequently another 4.75" tubing barrel pump was installed

In August, there was a minor workover to replace the polish rod, which was slightly bent due to alignment of the Ecoquip and causing some problems with leakage around the stuffing box. At this time, the downhole pressure measurement device (Promore ERD) malfunctioned and left only temperature measurements until the next workover in October was completed.

The surface drive Ecoquip unit was changed out for a few weeks in September with a smaller version with limited capacity to enable servicing and was returned to the original design when the service rig was on site for other work.

In October 2004, the pump failed again, likely due to a quick over pressuring of the flow line and suspected blowing of bottom hole drain. Given that there was no longer the steam requirement at this well, the high cost for a tubing pump and recent difficulties with these pumps, a 3.25" insert pump was installed next. There were no other workovers for the rest of the year.

1.3.2 P2 (108/12-24-83-07W4M)

In May 2004, the P1 well went down on pump failure after dynamometer cards indicated a problem. The pump teardown indicated general wear, particularly on the traveling valve. The pump had been running since May 2003 using a 3.25" insert type pump. A replacement 3.25" insert pump was installed. In September, the Lufkin pump jack had to be re-aligned by Weatherford so that the polish rod was stroking straight.

1.3.3 P3 (AA/04-24-83-07W4M)

For most of 2004 the P3 well was not operating due to insufficient pressure to operate gas lift. Additionally, the well was waiting on the CanK pump to return from lab testing. In October, a Weatherford VSH2 hydraulic surface unit was installed along with a 4.75" downhole tubing pump. Later in October, a minor workover was needed to change out the polish rod since it was leaking too much from the stuffing box. The workover revealed the previous polish rod was not fully spray coated and was upside down. The downhole spacing was also adjusted during this time.

To assist in analysis and troubleshooting, a pump-off controller was installed with radio communication back to a laptop at the Pilot Plant. Due to some electrical difficulties this had only moderate success and was not used to the best of its capabilities.

1.3.4 Steam Injection Wells

There were no workover operations on any of the steam injection wells during 2004. Although, in April 2004, three (3) separate tracers were injected into the injection wells for the purpose of monitoring possible fluid communication between the wells as would be evidenced by tracer returns taken from produced water from the production wells.

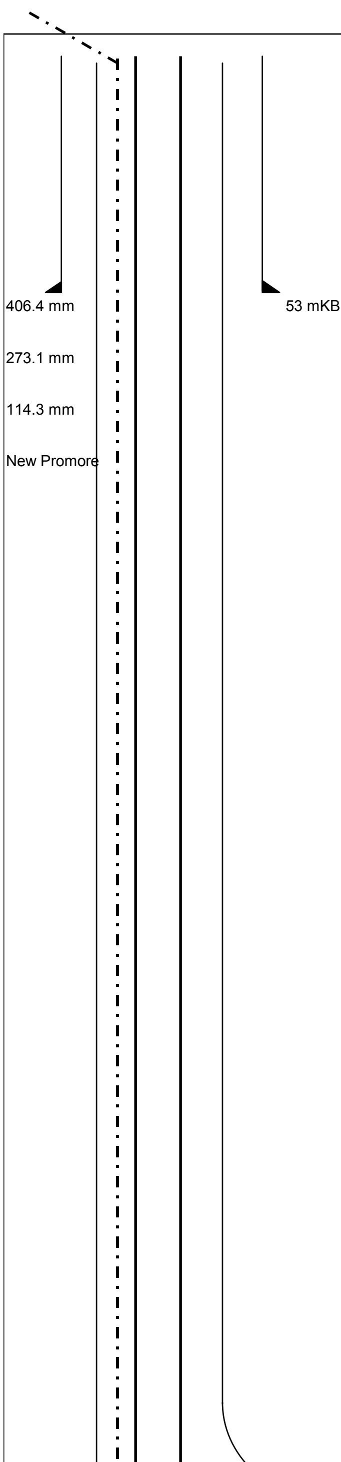
1.3.5 Water Disposal Wells

In October 2004, well 102/3-31-83-6W4M failed its packer test. The well has been locked out and is no longer used for disposal. The status of the well has been changed to observation so that no further work is required and pressures can be recorded from it to monitor the adjacent disposal well 103/3-31.

1.3.6 Source Water Supply Wells

There was no work done on the 1F1/8-25-83-7W5 well during 2004. The source water well approval was amended to include volumes for the rental steam generator to the end of 2006. If source water is required from this well beyond 2006 for the commercial or pilot projects another amendment will be necessary.

CONOCO PHILLIPS CANADA
HORIZONTAL DOWNHOLE WELL PROFILE



WELL NAME / UWI: CPC Resdeln P-1 Hz 106/05-24-083-07w4
FOREMAN: ALLAN GRAY   DATE: Oct 27 - 2004

KB ELEV 587.3 m **PBTD** 935 mKB **TD** 940(TVD mKB
KB - CSG 3.83 m **KB-THF** 3.58 m **KB-GR** m   Permanent Rig Anchors [X]

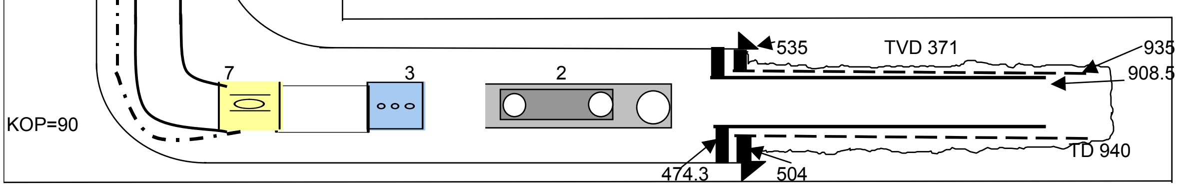
CASING/TUBING	SIZE (mm)	WEIGHT (kg/m)	GRADE	DEPTH (mKB)
Surface Casing	406.4	96.73	H-40	53.0
Intermediate Casing	273.1	67.71	L-80	535.0
Permanent Tail pipe	88.9	Hydrill 533		474.31 - 908.5 MD
Production Casing				
Liner	177.8	38.7	L-80	504 - 935 MD 0.005" wire wrapped
Tubing	114.3	14.14 STC 8rd	J-55	449.8
Perfs/ Open Hole, mKB	McMurray / ; /			
Old Perfs, mKB	Preperforated casing, Keystone wire wrapped Jt 20 & 33 blank			

FINAL TUBING STRING FROM BOTTOM UPWARD

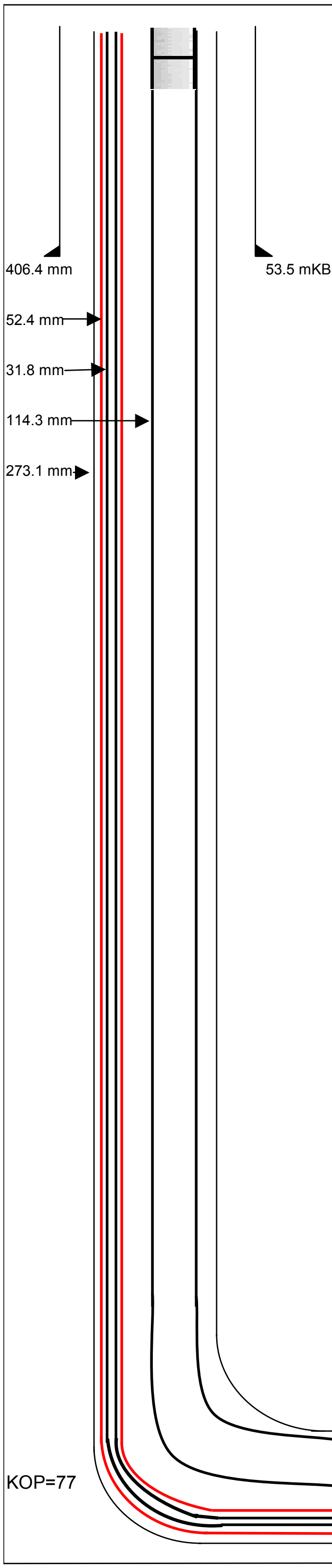
ITEM NO.	DESCRIPTION	LENGTH meters	TOP SET AT meters
1	1- Jt New 114.3mm Tbg c/w collar on Btm STC 8 rd threads	13.41	439.98
2	1 - 4.5" API - PSN <<NEW>>	1.03	438.95
3	1 - New 114.3mm pup Jt	4.01	434.94
4	1 - New Jt of 144.3mm Tbg	13.48	421.46
5	1 - Serviced Promore Tie in Sub	0.19	421.27
6	31 - Jts of <<NEW>> 114.3mm 14.14kg/m STC Tbg	413.34	7.93
7	1- New 114.3mm pup Jt	3.11	4.82
8	1 - New 114.3mm pup Jt	1.08	3.74
9	Tubing Hanger	0.16	3.58
10	11" BOP's required / No Riser spool needed		3.58
A	BHP 40 x 325 RHAFR 28 x 2 #BMW 2307		
B	1 - 28.5mm plain pony 1.8m		
C	40,000# shear coupling <<NEW>>		
D	Corod string # DR-85-000-11-8722 (340m)		
E	10 - 28.5mm NETB scrapered rods		
F	2 - 28.5mm ponies 2.4m plain and 1.8m scrapered		
G	<<NEW>> Full Metal Sprayed 10.9m x 38.1mm Polish rod		
H			
I			
J			
	TOTAL STRING LENGTH	449.81	
	K.B. TO TUBING HANGER FLANGE	3.58	
	SETTING DEPTH K.B.	453.39	

STRING WT 7500 daN   WT on PACKER n/a daN   WT on HANGER 7500 daN
TBG HANGER   TYPE Cameron   SIZE 228.6 x 114.3   SFC CSG STATUS Open/No flow
CASING BOWL   W.P. 14 MPa   MAKE Crown   FLANGED [X]   SCREWED [ ]
TUBING SPOOL   W.P. 14 MPa   MAKE StreamFlow   SIZE 339 x 279
MSTR VLV   No. n/a   TYPE   SIZE mm   MAKE Pumping wellhead
W.P. MPa   NACE TRIM? YES [ ]   NO [ ]
CSG VLV   No. 2   TYPE Gate   SIZE 52.8 mm   MAKE Crown
W.P. 14 MPa   NACE TRIM? YES [ ]   NO [ ]

REMARKS
No Riser Spool required on well. ----11" BOP's fit onto wellhead.
The BHP Will not come thru wellhead, there is a 1.8m pony above BHP so/as to strip WH off
Promore Tbg/Cable banded to Tbg with collar guards every collar
WALS corod Bonneyville 1-800-661-5654 (Eugene)



CONOCO PHILLIPS CANADA
HORIZONTAL DOWNHOLE WELL PROFILE



WELL NAME / UWI: CPC Resdlyn P2 Hz 108/12-24-083-07 W4
FOREMAN: Albert Florence DATE: 5/15/2004

KB ELEV 587.3 m **PBTD** 960 MD mKB **TD** 965 MD T mKB
KB - CSG m **KB-THF** 3.11 m **KB-GR** m Permanent Rig Anchors [X]

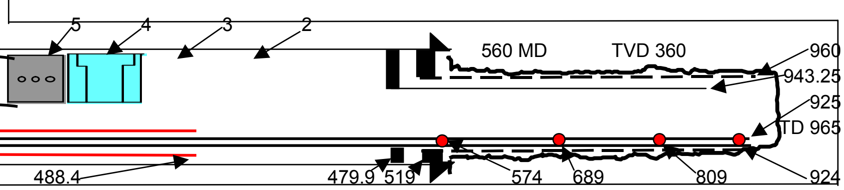
CASING/TUBING	SIZE (mm)	WEIGHT (kg/m)	GRADE	DEPTH (mKB)
Surface Casing	406.4	96.73	H-40	53.5
Intermediate Casing	273.1	67.71	L-80	560.0
Tubing	52.4	4.84 FJ	L-80	434.1
Instrument Coil String	31.8			Surface-925 MD(inside 52.4 mm)
Permanent Tail pipe	88.9	Hydrill 511 FJ	15.63	479.89 - 943.25
Liner	177.8	38.7	L-80	519 - 560 MD 0.005 " Keystone wire
Tubing	114.3	14.14	J-55	433.0
Perfs/ Open Hole, mKB	McMurray / Pre-perforated liner 519-960 MD; /			
Old Perfs, mKB				

FINAL TUBING STRING FROM BOTTOM UPWARD

ITEM NO.	DESCRIPTION	LENGTH meters	TOP SET AT meters
1	String Bottom		436.11
2	W/L re-entry EUE	0.16	435.95
3	Pup 114.3 mm EUE	2.51	433.44
4	PSN API 114.3 mmx 95.25 mm EUE	0.33	433.11
5	FIKE drain 4000 # burst EUE	0.15	432.96
6	xover EUE box x 8rd box	0.20	432.76
7	33 - Jts 114.3 mm x 14.14 kg/m J-55 8rd	424.90	7.86
8	Pup 114.3 mm 8 rd	4.55	3.31
9	Tubing hanger	0.20	3.11
10			3.11
A	40 - 325 RHAFR 34 - 3 - 0 BMW # 2212		
B	28.5 mm plain rod (38.1 mm pin)		
C	28.5 mm shear 40,000 #		
D	28.5 mm co-rod 360 m		
E	6 - 28.5 mm NETB 8/rod scrapered		
F	1 - 28.5 mm plain ponie		
G	1 - 38.1 mm x 10.97 mm Spray metal polish rod		
H			
I	Need to polish rod & pony to unseat BHP (5500 daN)		
J			
	TOTAL STRING LENGTH	433.00	
	K.B. TO TUBING HANGER FLANGE	3.11	
	SETTING DEPTH K.B.	436.11	

STRING WT 7500 daN WT on PACKER n/a daN WT on HANGER 7500 daN
TBG HANGER TYPE TC-EN SIZE 228.6x114.3 SFC CSG STATUS Open/No flow
CASING BOWL W.P. 14 MPa MAKE Crown FLANGED [X] SCREWED [ ]
TUBING SPOOL W.P. 14 MPa MAKE Cooper cameron SIZE 228.6 x 103.2
MSTR VLV No. n/a TYPE SIZE mm MAKE Pumping wellhead
W.P. MPa NACE TRIM? YES [ ] NO [ ]
CSG VLV No. 2 TYPE Gate SIZE 52.4 mm MAKE Crown
W.P. 14 MPa NACE TRIM? YES [ ] NO [ ]

REMARKS: BHP Insert pump String 2500 daN, 5500 to unseat. 40-325 RHAFR 34-3-0 BMW # 2212
Need to have string wt on bridle to remove/replace neck pin in Horse head
Need to remove Radigan to take BHP from well
Need 36" spool to N/U BOP stack 4000# Burst in Fike drain(BMW Lloyd)
Two tubing hangers, Lower hanger is 6" in diameter
40,000 # shear on co-rod string, between co-rod and plain rod (BMW Lloydminister 780-875-2730)



GULF HZNTL P3 RESDELN
Surmont Pilot SAGD
Production Well.
P3 - 1AA / 04-24-083-07 / W4M

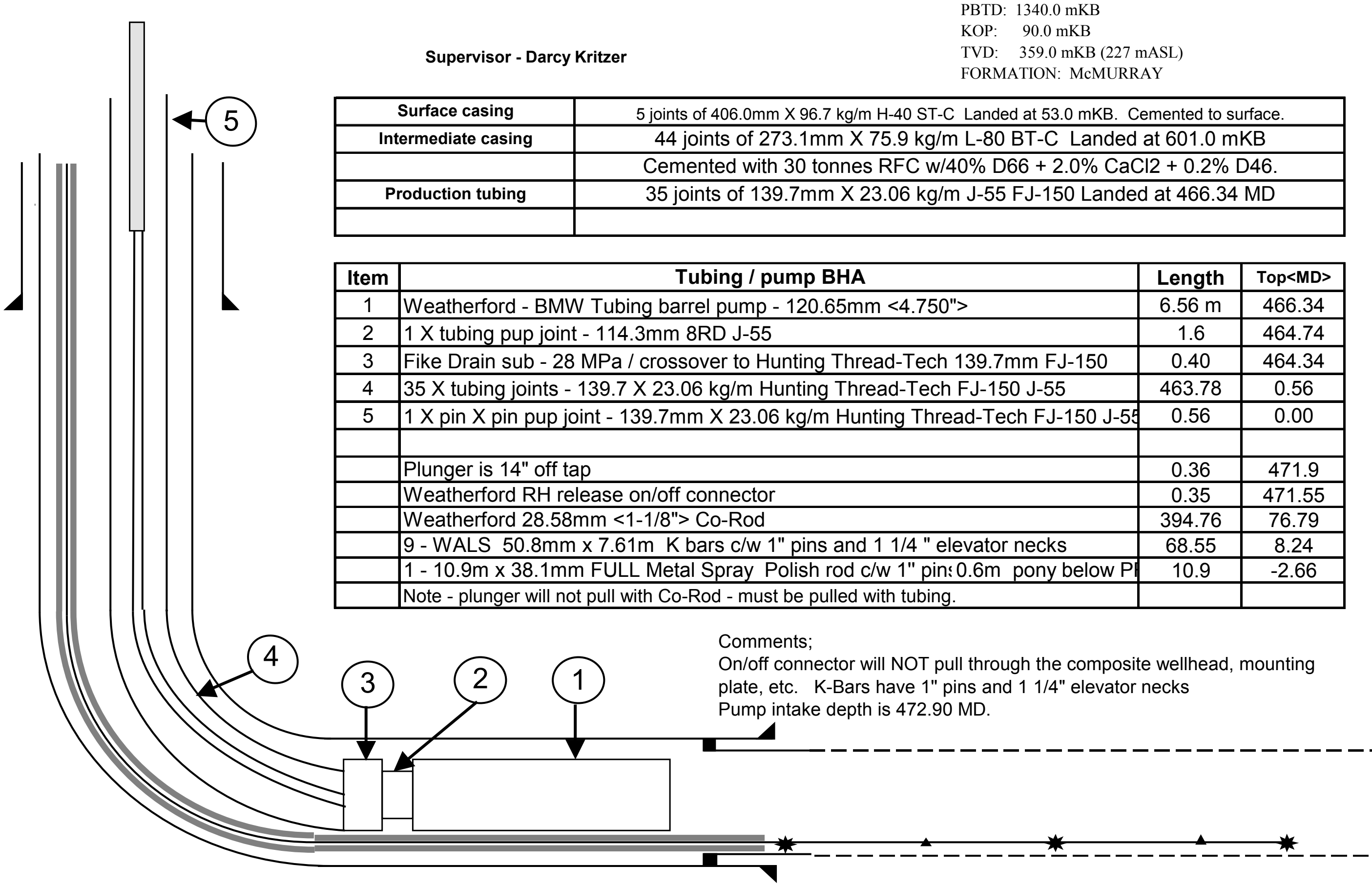
Date October 27 - 04
Allan Gray

KB: 586.13 m KB to GR 4.5 m
GL: 581.63 m KB to THF 3.31 m
TD: 1345.0 mKB
PBTD: 1340.0 mKB
KOP: 90.0 mKB
TVD: 359.0 mKB (227 mASL)
FORMATION: McMURRAY

Supervisor - Darcy Kritzer

Surface casing	5 joints of 406.0mm X 96.7 kg/m H-40 ST-C Landed at 53.0 mKB. Cemented to surface.
Intermediate casing	44 joints of 273.1mm X 75.9 kg/m L-80 BT-C Landed at 601.0 mKB
	Cemented with 30 tonnes RFC w/40% D66 + 2.0% CaCl2 + 0.2% D46.
Production tubing	35 joints of 139.7mm X 23.06 kg/m J-55 FJ-150 Landed at 466.34 MD

Item	Tubing / pump BHA	Length	Top<MD>
1	Weatherford - BMW Tubing barrel pump - 120.65mm <4.750">	6.56 m	466.34
2	1 X tubing pup joint - 114.3mm 8RD J-55	1.6	464.74
3	Fike Drain sub - 28 MPa / crossover to Hunting Thread-Tech 139.7mm FJ-150	0.40	464.34
4	35 X tubing joints - 139.7 X 23.06 kg/m Hunting Thread-Tech FJ-150 J-55	463.78	0.56
5	1 X pin X pin pup joint - 139.7mm X 23.06 kg/m Hunting Thread-Tech FJ-150 J-55	0.56	0.00
	Plunger is 14" off tap	0.36	471.9
	Weatherford RH release on/off connector	0.35	471.55
	Weatherford 28.58mm <1-1/8"> Co-Rod	394.76	76.79
	9 - WALS 50.8mm x 7.61m K bars c/w 1" pins and 1 1/4 " elevator necks	68.55	8.24
	1 - 10.9m x 38.1mm FULL Metal Spray Polish rod c/w 1" pin 0.6m pony below Pl	10.9	-2.66
	Note - plunger will not pull with Co-Rod - must be pulled with tubing.		



Comments;
On/off connector will NOT pull through the composite wellhead, mounting plate, etc. K-Bars have 1" pins and 1 1/4" elevator necks
Pump intake depth is 472.90 MD.

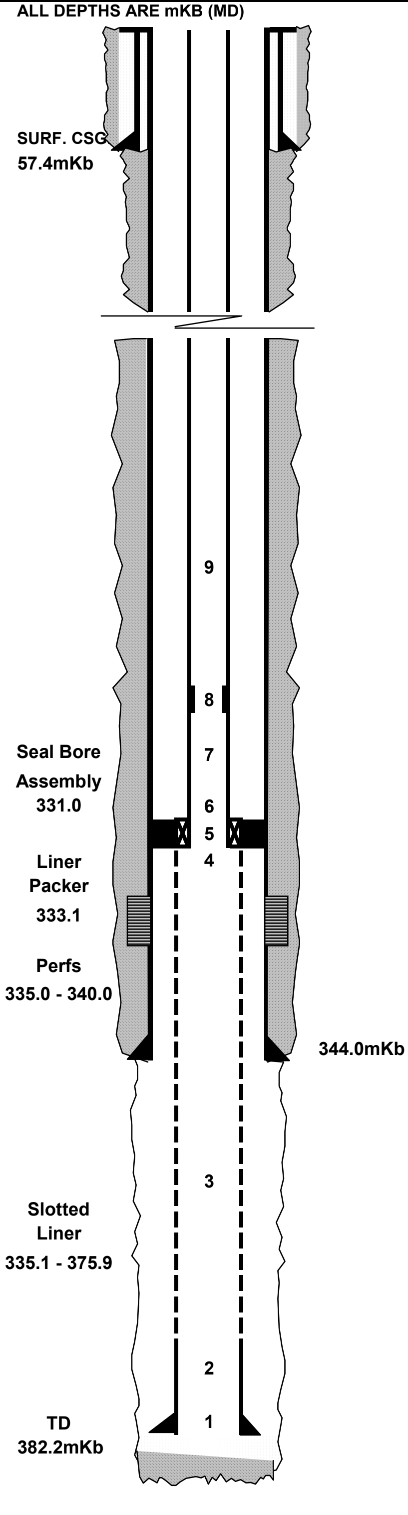
Instrument Bundle: 3 - pressure / temperature probes at 590, 950 and 1310 mKB. 2 - thermocouple junctions at 770 and 1130 mKB. **Coil Tubing** - 38.1 mm OD, X HS-70 landed at 1310 mKB.

Guide String- 61 jts of 52.4mm IJ tubing landed at 590.77 MD.

Liner Data- 273.1 mm x 177.8 mm Secure thermal liner hanger at 578.26 mKB with 50 joints (#2 through #51) of 0.005” Regent rolled programmed slotted liner. Slotted section from 633.11 - 1328.0 mKB. Base pipe consists of 177.8 mm, 34.22 kg/m, L-80, BT&C. 5 joints (# 1, 52, 53, 54 and 55) are blank. Liner landed at 1340.0 mKB.

CONOCO CANADA RESOURCES
WELL DIAGRAM (EXISTING CONFIGURATION)

ALL DEPTHS ARE mKB (MD)



WELL NAME: **Disposal Well 102/03-31-083-06 W4M**

PREPARED BY: Shawn Malone rev Deepa Thomas | DATE: 02-17-2004

ELEVATIONS (meters):

TD	382.24	KB Elev.	541.00	KB to CF Dist. H	2.30
PBTD	372.42	Ground Elev.	537.90	KB to Ground	3.10

CASING/TUBING	SIZE (mm)	WEIGHT (Kg/m)	GRADE	DEPTHS (m)
Surface Casing	219.10	35.71	J-55	57.43
Prod. Casing	139.70	20.83	J-55	344.00
Liner	88.90	13.84	J-55	335.09 - 375.87
Tubing	73.00	9.67	J-55	331.40

BOTTOM HOLE ASSEMBLY:

ITEM	DESCRIPTION	LENGTH (m)	Top at (m KB)
	String Bottom.		375.87
1	1 - Float Shoe.	0.44	375.43
2	1 - 88.9mm Pup Joint.	1.85	373.58
3	4 - Jts. 88.9mm Slotted Tubing Liner.	38.49	335.09
4	1 - Seal Bore Extension.	1.28	333.81
5	1 - Cardium Seal Bore Permanent Packer.	0.68	333.13
6	1 - Seal Assembly 0.8m pulled up.	2.09	331.04
7	1 - Jt. 73.0mm Tubing	9.60	321.44
8	1 - PSN	0.33	321.11
9	32 - Jts. 73.0mm Tubing.	304.70	16.41
10	1 - Jt. 88.9mm Pup Joint.	1.91	14.50
11	1 - Jt. 73.0mm Tubing	9.60	4.90
12	1 - Tubing Hanger & Nipple	2.60	2.30
13			
	TOTAL STRING LENGTH	373.57	
	K.B. TO TUBING HANGER FLANGE	2.30	
	SETTING DEPTH K.B.	375.87	

NOTE:

PUMP AND ROD ASSEMBLY

PERFORATION INTERVALS

13 SPM, 90 deg, 32 grm from 335.0 - 340.0 mKb.
Slotted Liner from 335.09 - 375.87 mKb

2 FACILITIES

There were no major facilities modifications at the Surmont Pilot in 2004.

An extensive HazOp was completed on the Surmont Pilot facilities in February 2004. This study identified a number of minor risks, operability issues and deviations from the as-built P&IDs. Operations have since successfully mitigated all of the major outstanding items and a major P&ID drawing update is complete.

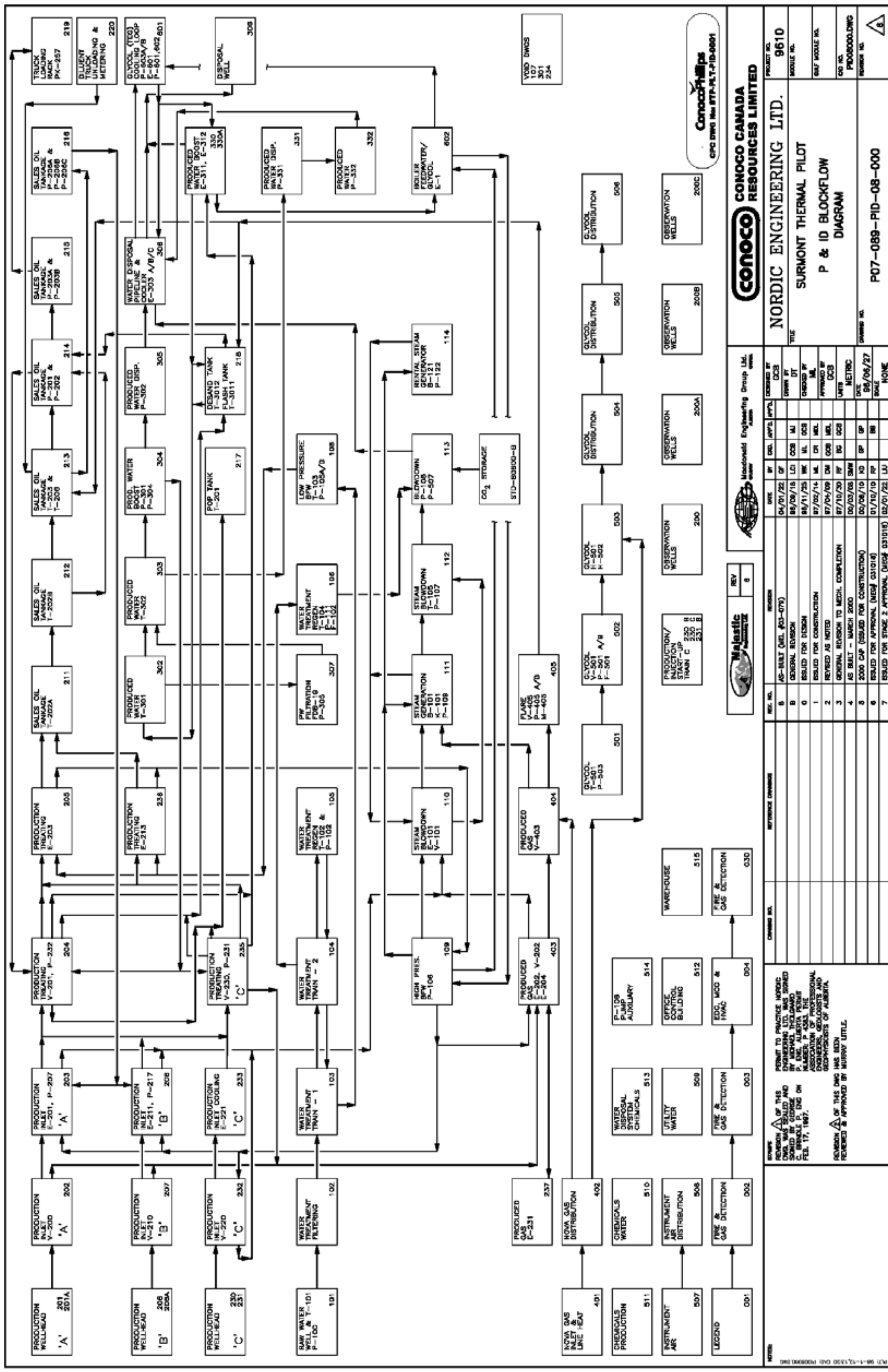
The June 2004 turnaround was routine in nature. All PSVs in the facility were serviced, the steam generator was cleaned (pigged) and some minor header piping was added to facilitate meter testing.

Multiphase metering testing continued at the Pilot in 2004. A Quadrant edge orifice meter was successfully tested for commercial use for measuring emulsion flow. An Agar OW-201 series water cut meter was also tested successfully and will be included in the commercial facilities. Later in the year, a FMC multi-phase meter was tested however the test was inconclusive due to problems with flow ranges.

With respect to water handling and processing, there continued to be fouling problems and resulting high differential pressures on the produced water exchangers. The belief is that a recent switch of chemical providers, while providing good quality separation, caused solids to carry over with the water and drop out downstream of the treater. Mitigating actions include blowdown washes, physical cleanings with pressure trucks and a solvent to aid the solid suspension qualities of the water. In addition, the rental steam generator installed in 2003 operated to capacity, but experienced longer down times during the year due to parts sourcing problems and lack of qualified service technicians.

From a plant optimization perspective, a "Six Sigma" process was initiated. The goal of the program is to maximize plant efficiency through greater steam output and less fuel usage. It is hoped that this process will not only improve Pilot efficiency, but also be applied to the Phase I Commercial Plant once it is in a steady state operation.

The 9-25 disposal well experienced some plugging at the wellhead meter. The plugging material was found to be pieces of mastic (pipeline joint compound). It is likely the mastic was over applied, and future applications in the commercial phase will have to be more closely observed.


CONOCO CANADA RESOURCES LIMITED
NORDIC ENGINEERING LTD.
SURMONT THERMAL PILOT
P & ID BLOCKFLOW DIAGRAM
P07-089-PID-08-000

3 INSTRUMENTATION IN WELLS

The data tables from the thermocouples and piezometers are included electronically with this report.

3.1 Observation Wells

In June 2004 the thermoucouple string was re-installed in OB 38 and moved up 4.5 m at OB22.

3.2 Horizontal Wells

There were no changes to the coiled tubing instrumentation or the Promore gauges strings in 2004. However, the pressure component of the Promore ERD gauges at the heel of P1 well failed in August 2004.

3.3 Observation Well Responses

There are six observation wells located along the two original SAGD well pairs as shown in Section 1. These wells are OB 18, 41, 36 and 24 along the P1/S1 well pair, and OB 17 and 22 along the P2/S2 well pair. A further five observation wells are located along the P3/S3 well pair (P3/S3). These wells are OB 20, 26A, 37, 38 and 39. OB 25 is located between the P1/S1 and P3/S3 well and instrumented with piezometers in the bitumen and top water zone. The OB well layouts are illustrated in Section 1

The OB 24 well has thermocouples only in the upper part of the pay zone and the OB 18 well has been non-operational for some time and is scheduled for abandonment in 2005. The OB 41 well was drilled to replace by the OB 18 well and drilled in close proximity.

3.3.1 OB 18 (00/12-24-83-07 W4M)

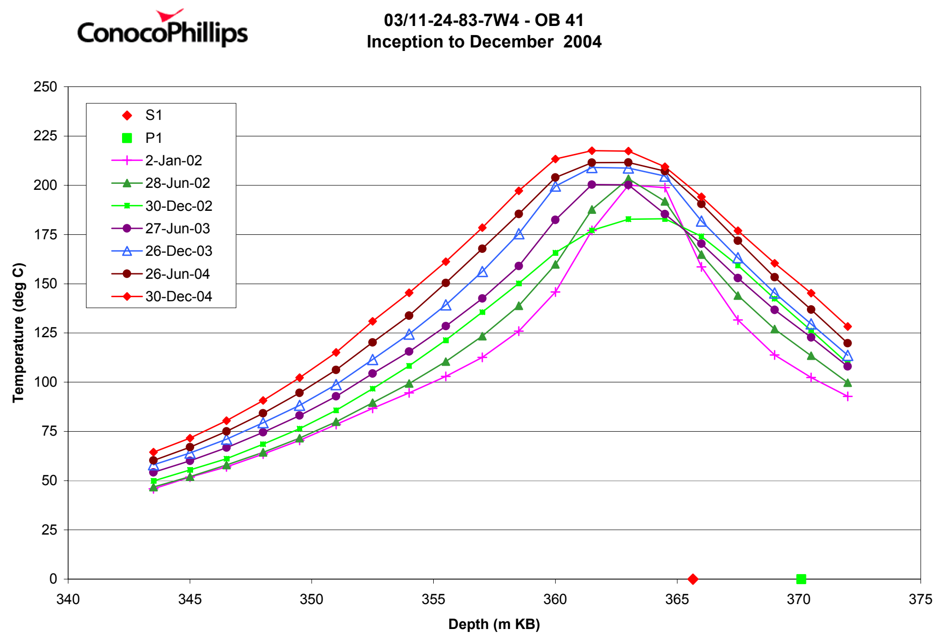
Lateral separation is estimated to be 1.0 m from S1 and 0.6 m from P1 according to surveys. This observation well is still non-operational and will be abandoned in 2005.

3.3.2 OB 41 (103/11-24-83-07 W4M)

Lateral separation is estimated to be 11.3 m +/- 5.6 m from S1 and 12.1 m +/- 5.5 m from P1 according to ranging surveys. The OB 41 well was drilled, near the OB 18 well, because the OB 18 well exhibited early steam development at this location.

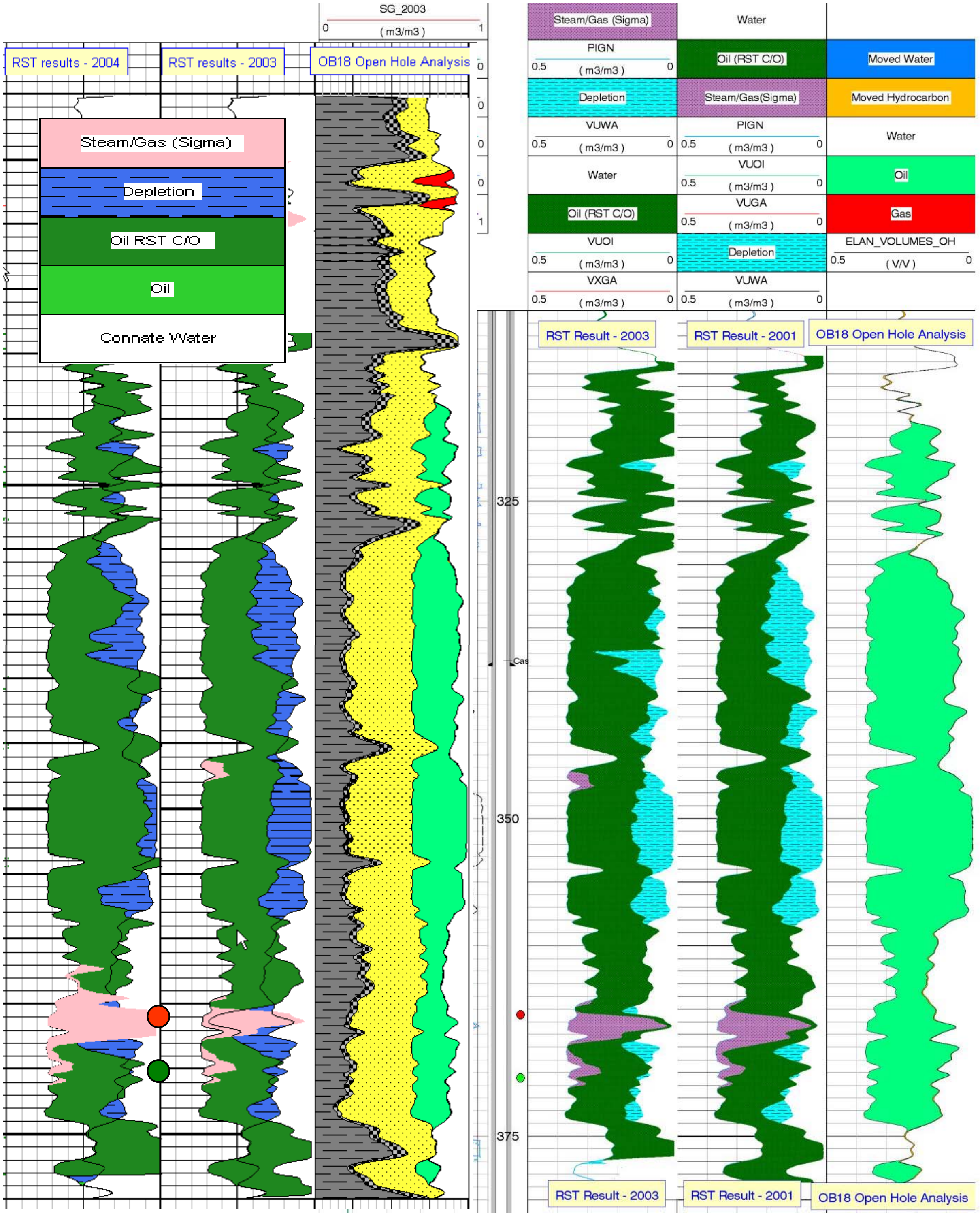
The following plot illustrates steam temperatures at the injector level of the OB 41 well.

A steam chamber has been present at this well since November 2001 albeit the steam rise rate has been slow. The current temperature profile indicates the 200º C level is 7 m above the injection well.



To understand the fluid distribution at this location neutron/carbon/oxygen logs (RST) have been run on this well in 2001, 2003 and in June 2004. Theses logs indicated that there is a thin steam chamber at this location. The 2004 RST log indicated a steam chamber growth of 2 m and is consistent with the thermocouple data.

The logs are included on the following page.

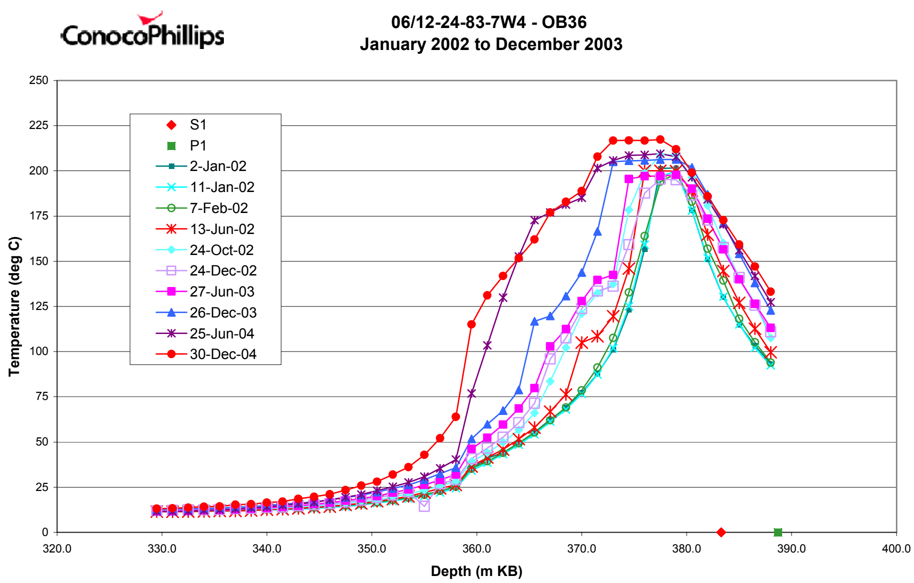

SG_2003
0
(m3/m3)
1
RST results - 2004
RST results - 2003
OB18 Open Hole Analysis
Steam/Gas (Sigma)
Depletion
Oil RST C/O
Oil
Connate Water
Steam/Gas (Sigma)
Water
PIGN
0.5 (m3/m3) 0
Oil (RST C/O)
Moved Water
Depletion
Steam/Gas(Sigma)
Moved Hydrocarbon
VUWA
0.5 (m3/m3) 0
PIGN
0.5 (m3/m3) 0
Water
Water
VUOI
0.5 (m3/m3) 0
Oil
Oil (RST C/O)
VUGA
0.5 (m3/m3) 0
Gas
VUOI
0.5 (m3/m3) 0
Depletion
ELAN_VOLUMES_OH
0.5 (V/V) 0
VXGA
0.5 (m3/m3) 0
VUWA
0.5 (m3/m3) 0
RST Result - 2003
RST Result - 2001
OB18 Open Hole Analysis
325
350
375
RST Result - 2003
RST Result - 2001
OB18 Open Hole Analysis

OB 41 RST log

3.3.3 OB 36 (106/12-24-83-07 W4M)

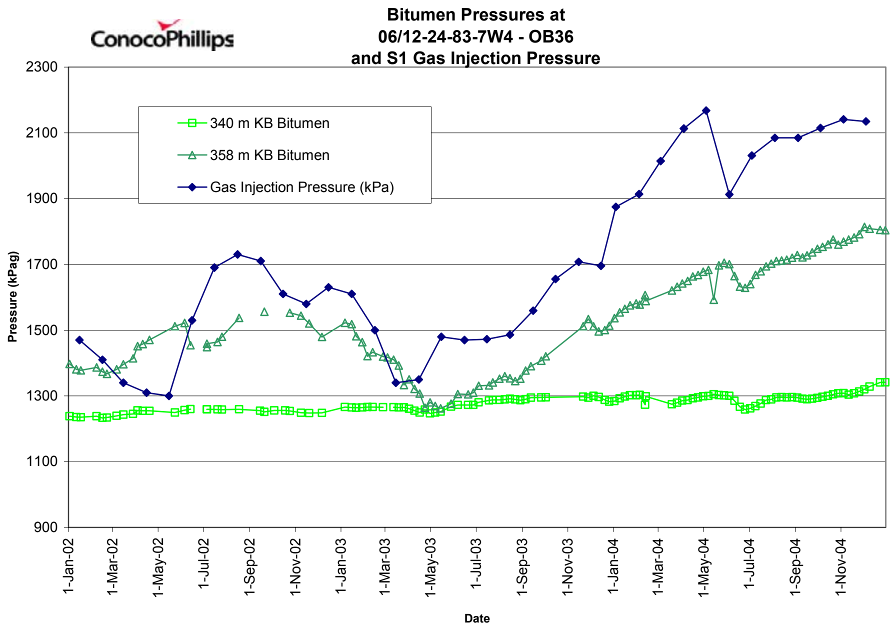
Lateral separation is estimated to be 2.1 m from S1 and 1.6 m from P1 according to surveys.

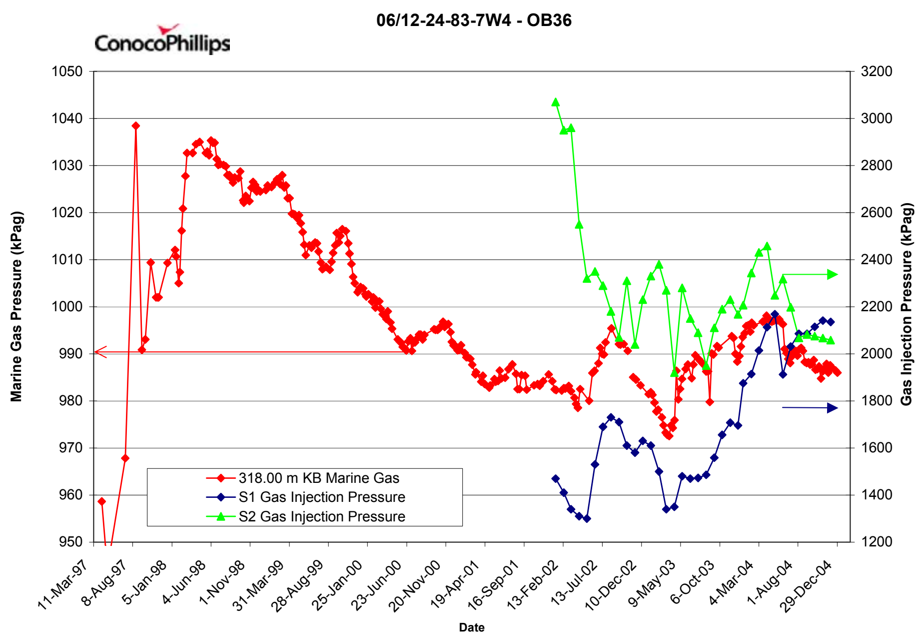
The plot that follows illustrates the temperatures observed at the OB 36 well from January 2002 to December 2004. The temperature profiles indicate that steam temperature conditions were present over the last year. Steam temperatures are observed approximately 10 m above the level of the injection well.



There were four piezometers installed in the OB 36 well, three in the bitumen and one in the Wabiskaw (marine) gas zone. One of the bitumen piezometers has been non-operational for years. The two remaining bitumen piezometers at OB 36 provide additional information about the location of the steam chamber front and conditions ahead of the front. At the end of December 2004 the piezometer at 340 m KB still showed limited interaction with the steam chamber at the P1/S1 well pair. The piezometer at 358 m KB indicated a response in relation to the steam chamber pressure.

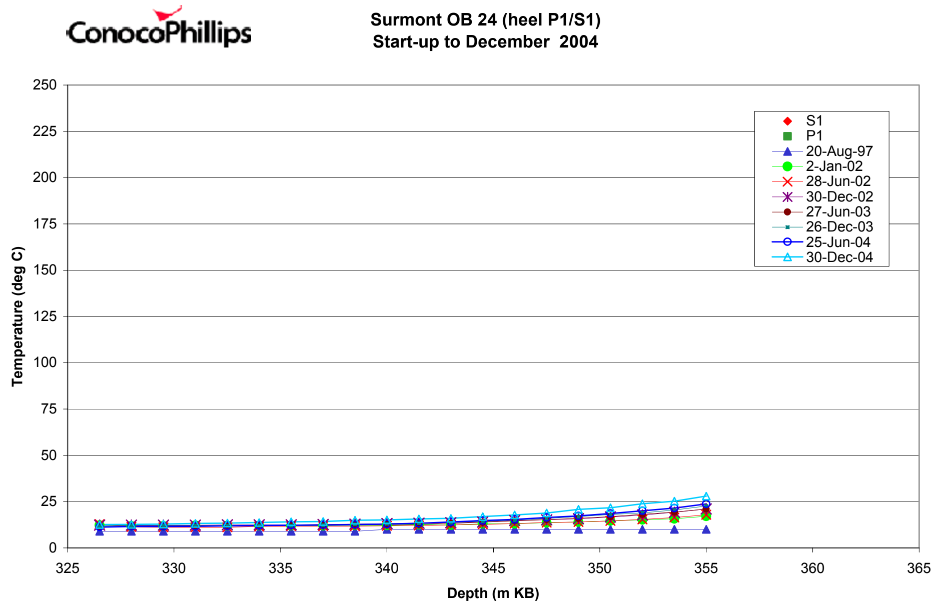
The piezometer in the gas zone at the OB 36 well in the past has been interpreted to be equalizing with the lower pressured channel gas zone. Although the two gas zones are still in communication there is a stronger correlation with the S2 steam injection pressure and the marine gas pressure response observed at this location. The S1 steam injection pressure is also plotted for reference. The McMurray (channel) gas is not monitored at this location. However, there is a piezometer in the McMurray (channel) gas zone at the OB 24 well.



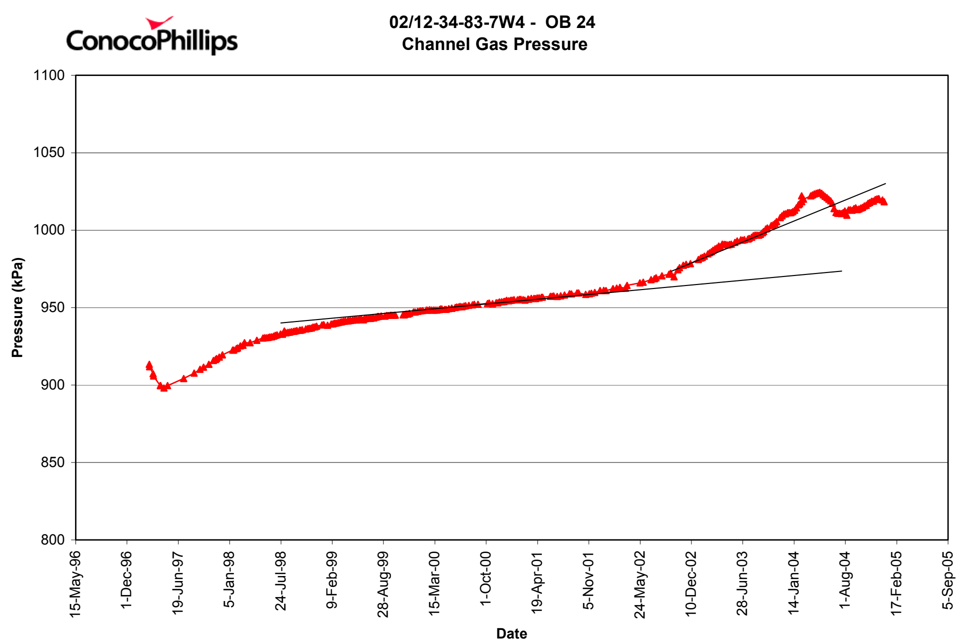


3.3.4 OB 24 (102/12-24-83-07 W4M)

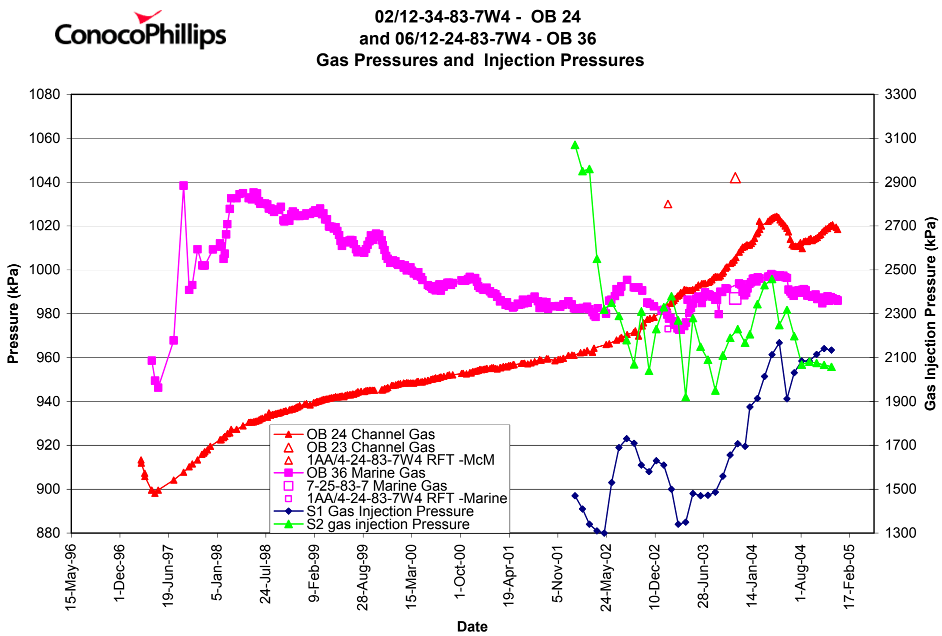
Lateral separation of the OB 24 well is estimated to be 13.1 m from S1 and 13.7 m from P1 according to surveys. The thermocouple string is located at the top of the well such that the lowest thermocouple is 35 m above the S1 horizontal injection well. Because of the lateral separation of OB 24 from the P1/S1 well pair, and the location of the thermocouples high in the pay zone, a small temperature response has been detected at the lower thermocouples at this observation well, as illustrated by the embedded plot.



There is only one piezometer installed at the OB 24 well. It is installed in the McMurray (channel) gas zone and continues to show an increasing pressure since shutting-in the gas in April 1997. As previously mentioned, this pressure response has been interpreted in the past to be equalizing with the higher pressured Wabiskaw (marine) gas zone. Although the two gas zones are still communicating with each other, the changes in the slope of the pressure response suggest that the McMurray (channel) gas zone at OB 24 is in hydraulic pressure communication with the approaching steam chamber. A plot of the OB 24 pressure response follows.



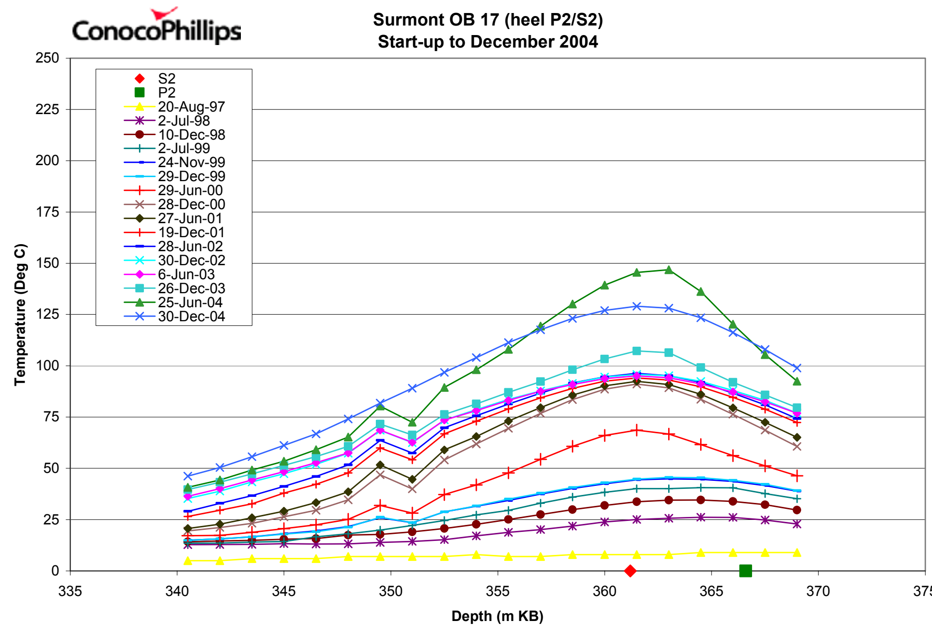
The following plot illustrates the pressure responses measured in the gas zone at both the OB 36 and OB 24 wells. The plot indicates that the Wabiskaw (marine) gas at the OB 36 well is communicating with S2 steam injection pressures and that the McMurray (channel) gas at the OB 24 well is communicating with S1 steam injection pressures.



3.3.5 OB 17 (104/12-24-83-07 W4M)

Lateral separation is estimated to be 10.3 m from S2, and 8.9 m from P2 according to surveys.

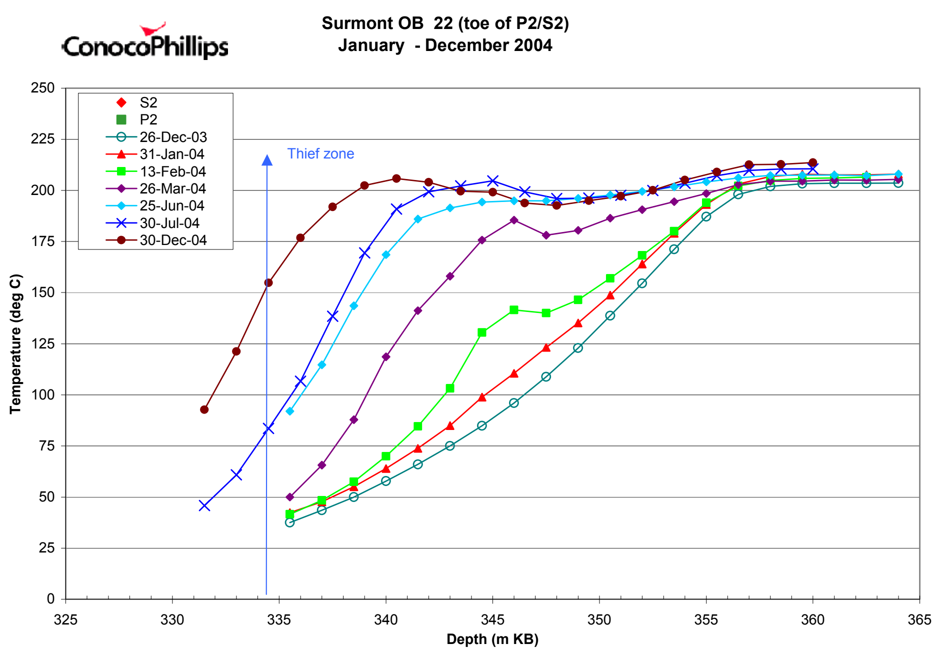
By January 2004, a significant temperature response of 147° C was detected, but a steam chamber was not detected. By December 2004, the temperature had decreased to129° C , as indicated by the plot that follows.



There are no piezometers installed at the OB 17 well

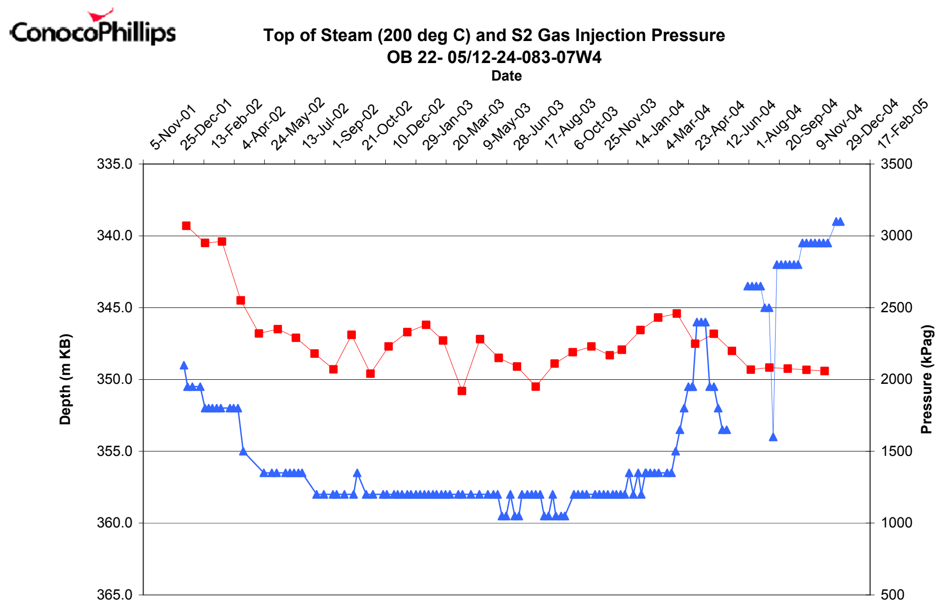
3.3.6 OB 22 (105/12-24-83-07 W4M)

Lateral separation is estimated to be 0.2 m from S2, and 0.0 m from P2 according to surveys, indicating that this well should be right at the location of the horizontal wells. The temperature profile of the well indicates that the level of the steam chamber was at 356.5 m KB in January 2004. In February the temperature 10 m above at 346 m KB



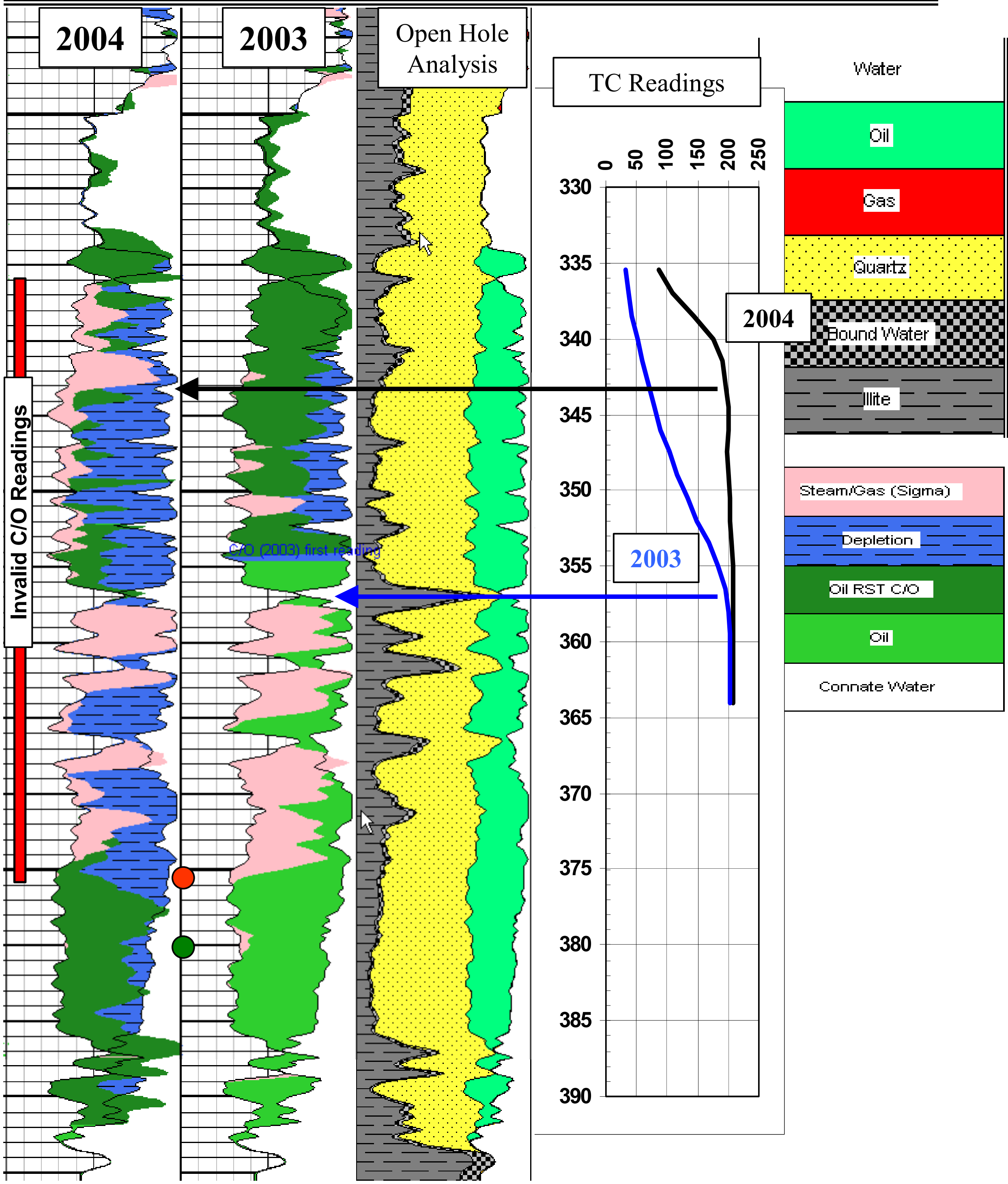
began to increase indicating that steam was approaching the observation from the side. By June 25 the temperatures above the steam zone had increased by nearly 75° C from the January reading and by July 30 steam was detected at two different levels at this location such that the top of the steam is approximately 6 m from the thief zone.

The following plot of the top of steam and S2 gas injection pressure illustrates the relationship of the injection pressure with the apparent top of the steam chamber. The S2 gas injection pressure is roughly 500 kPa higher than the steam chamber pressure due to skin damage at this well but decreased significantly towards the end of the year.



There are no piezometers installed at the OB 22 location.

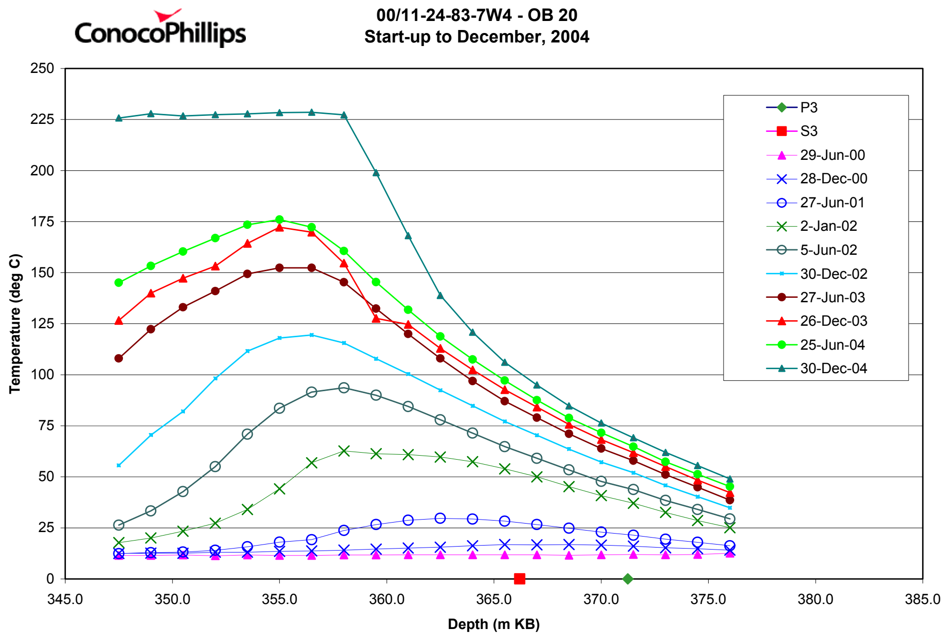
A neutron/carbon/oxygen log was also run at OB 22 run at this location in April 2003. The steam zone from the 2003 RST log matched the temperature profiles and the interval of apparent fall back in steam chamber height appears to be saturated by bitumen with some water and increasing amounts of vapour (methane & steam) towards the top of the steam chamber. To verify the above interpretation, the well was re-logged in June 2004 after raising the apparent steam chamber height. The carbon/oxygen tool failed in zone of investigation as the wellbore was fluid filled and tool went over 150°C. The Sigma tool was still good for steam/gas height as when correlated to temperature it showed top of steam. There appears to be a possible gas front before steam chamber.


2004
2003
Open Hole Analysis
TC Readings
Invalid C/O Readings
C/O (2003) first reading
0
50
100
150
200
250
330
335
340
345
350
355
360
365
370
375
380
385
390
2004
2003
Water
Oil
Gas
Quartz
Bound Water
Illite
Steam/Gas (Sigma)
Depletion
Oil RST C/O
Oil
Connate Water

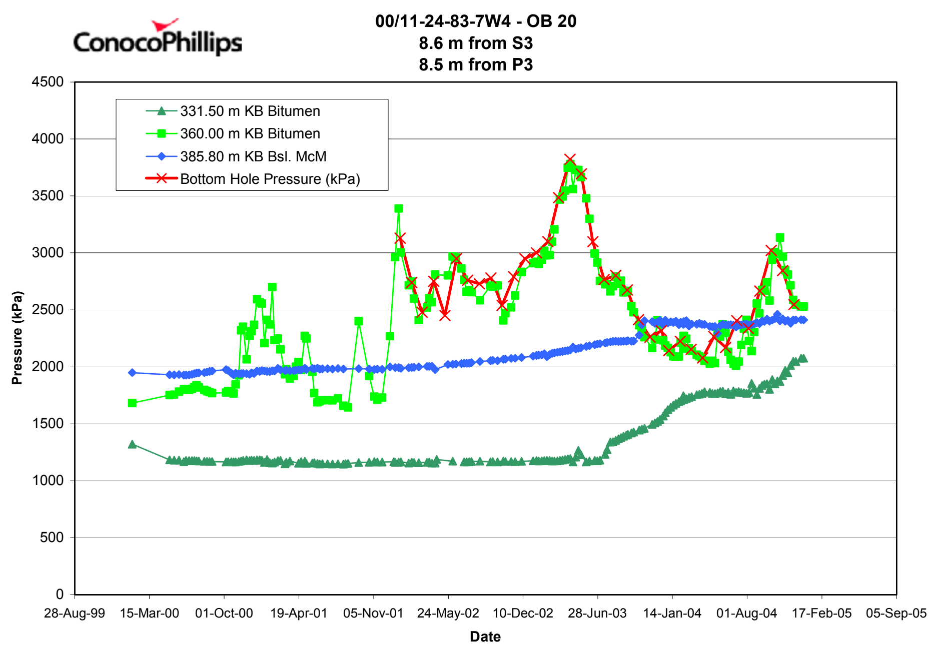
OB 22 RST log

3.3.7 OB 20 (100/11-24-83-07 W4M)

Lateral separation is 8.6 m from S3 and 8.5 m from P3. This observation well is located at the heel of the P3 horizontal well. A plot of the temperature profile at this well as shown below illustrates that steam is present at least 19 m above the injector at this location.



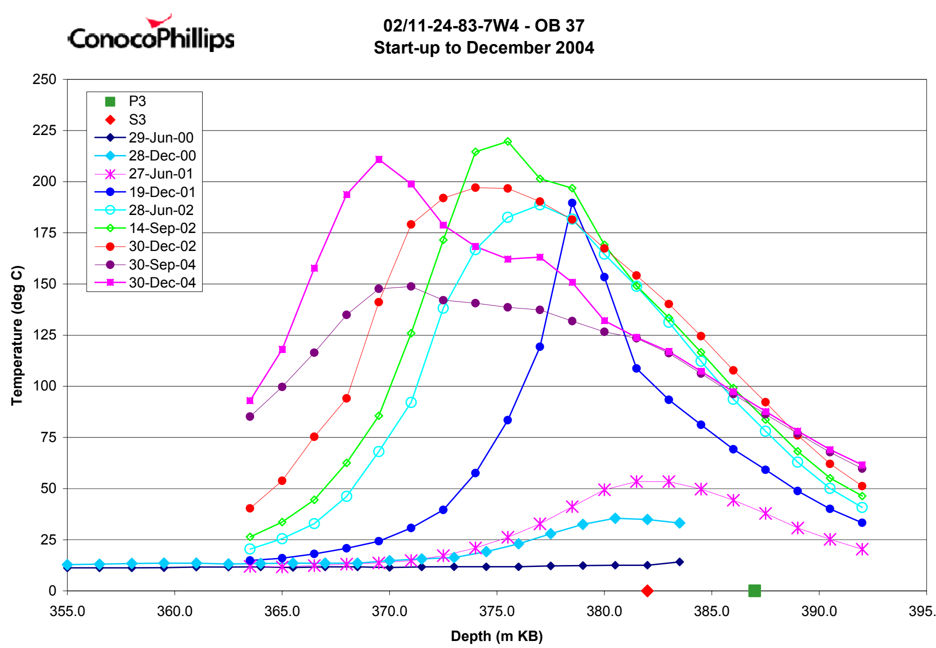
There are three piezometers installed in the OB 20 well, one in the Basal McMurray and two in the bitumen zone. The graph of the three piezometers and the bottom hole pressure at the S3 well indicate that piezometer at 360 m KB responds to S3 gas injection



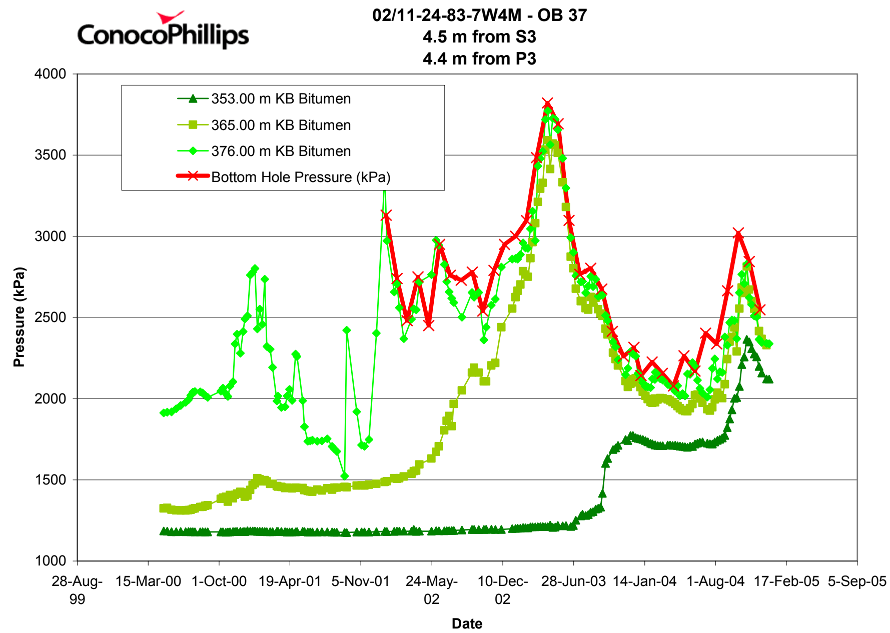
pressure. Over the last two years the piezometer in the bitumen at 331.5 m KB has exhibited an increasing pressure trend. Over the past two years the Basal McMurray piezometer has similarly exhibited an increasing pressure trend.

3.3.8 OB 37 (102/11-24-83-07 W4M)

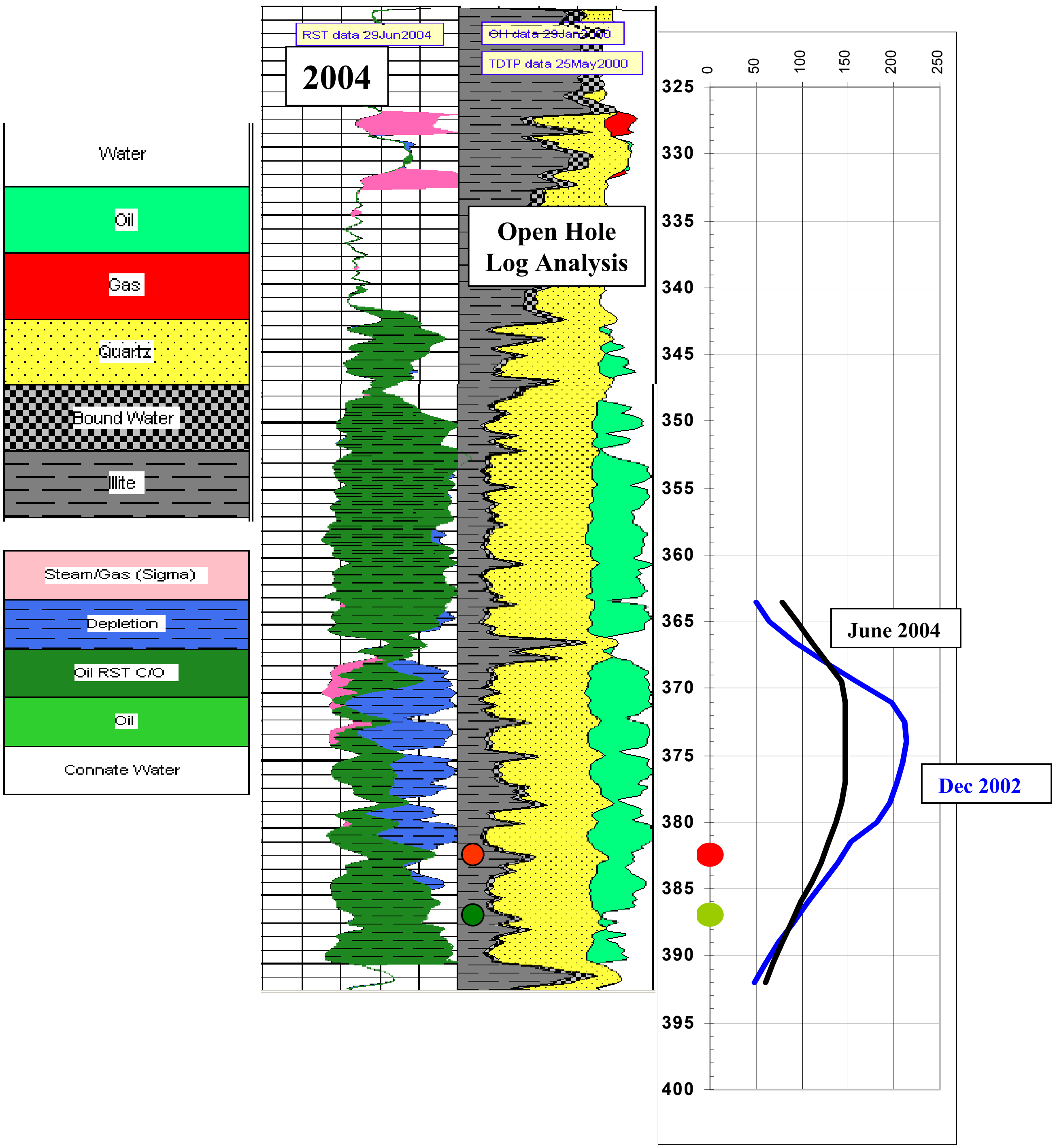
The OB 37 well is located approximately 1/4 of the way from the heel to the toe of the S3/P3 horizontal well pair. Lateral separation is 4.5 m from S3 and 4.4 m from P3. Steam chamber temperatures were observed at this well just above the steam injector in January 2002. The temperature profile plot indicates that the steam chamber continued to develop until December 2002 after which the apparent steam chamber top continued to fall back due to restricted production, the lack of steam capacity and lift issues. In September of 2004 similar to OB 22, temperatures began to increase from above the last known vertical location of steam suggesting that steam was approaching the OB well location from the side. By December 2004 temperatures in excess of 200° C were observed 12.5 m above the injector. Conduction heating in still occurring as indicated by the increasing temperatures at the upper most thermocouples.



Three piezometers were installed in the OB 37 well in the bitumen zone. The two lower most piezometers, which are 6 and 17 m above the level of the injection well, showed a pressure response to steam injection much earlier than the upper most piezometer at 353 m KB. This piezometer is 30 m above the injector and started showing a pressure response to steam injection in September 2004 although a pressure response was also seen in September 2002 after a high pressure cycle. The piezometer data and gas injection pressure are illustrated following page.



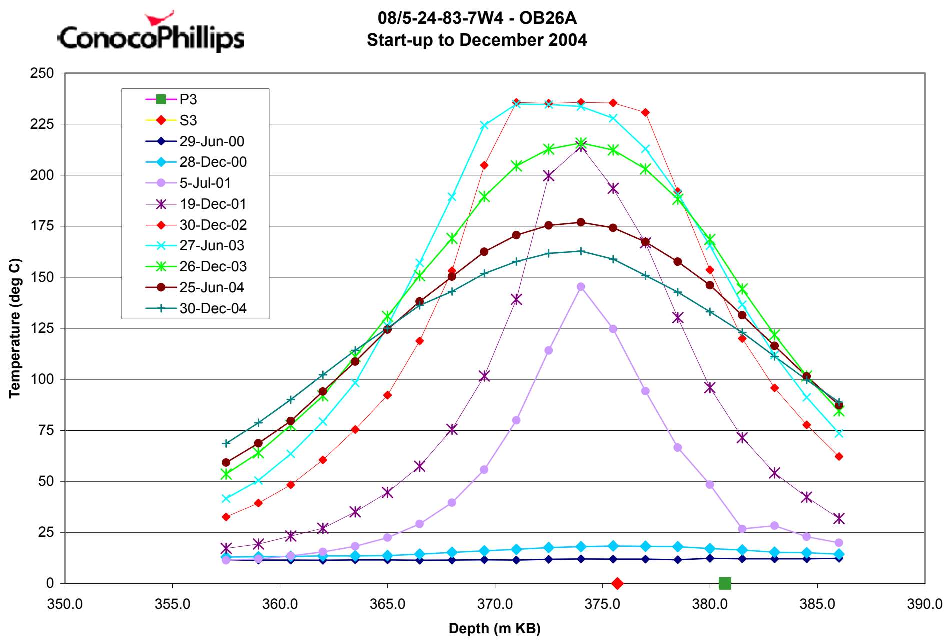
A RST log was also run at the OB 37 well in June 2004. This log indicated that there is a swept zone as high as 367.5 m KB in June 2004 and that there may be evidence of gas ahead of the steam front. There is good agreement with the highest temperature of 210° C observed at 372.5 m KB at this location from thermocouples in December 2002. The log and thermocouple profile is illustrated on the following page.


Water
Oil
Gas
Quartz
Bound Water
Illite
Steam/Gas (Sigma)
Depletion
Oil RST C/O
Oil
Connate Water
RST data 29Jun2004
2004
TDTP data 25May2000
Open Hole Log Analysis
0
50
100
150
200
250
325
330
335
340
345
350
355
360
365
370
375
380
385
390
395
400
June 2004
Dec 2002

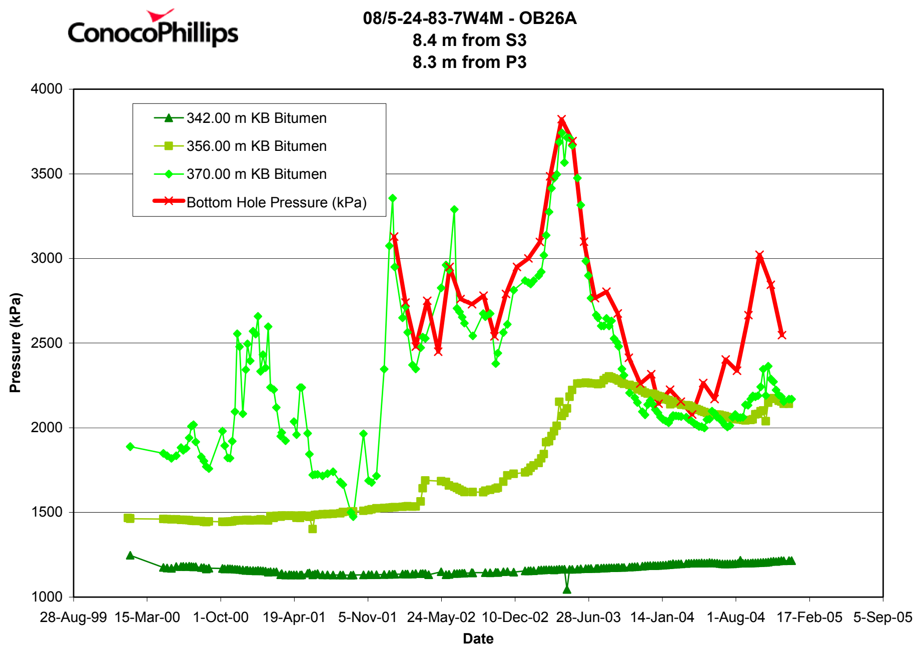
OB 37 RST log

3.3.9 OB 26A (108/5-24-83-07 W4M)

Lateral separation of OB 26A is 8.4 from S3 and 8.3 m from P3. This observation well is located ½ way down the horizontal trajectory of the S3/P3 well pair. Steam temperatures were first observed at this location in November 2001. The temperature profile plot illustrates the steady growth of the steam chamber at this location until May 2003, when the steam chamber was 6.2 m above the S3 injection well. Since May 2003 and throughout 2004 the steam chamber continued to fall back although conduction heating is still occurring as indicated by the higher temperatures at the upper thermocouples.

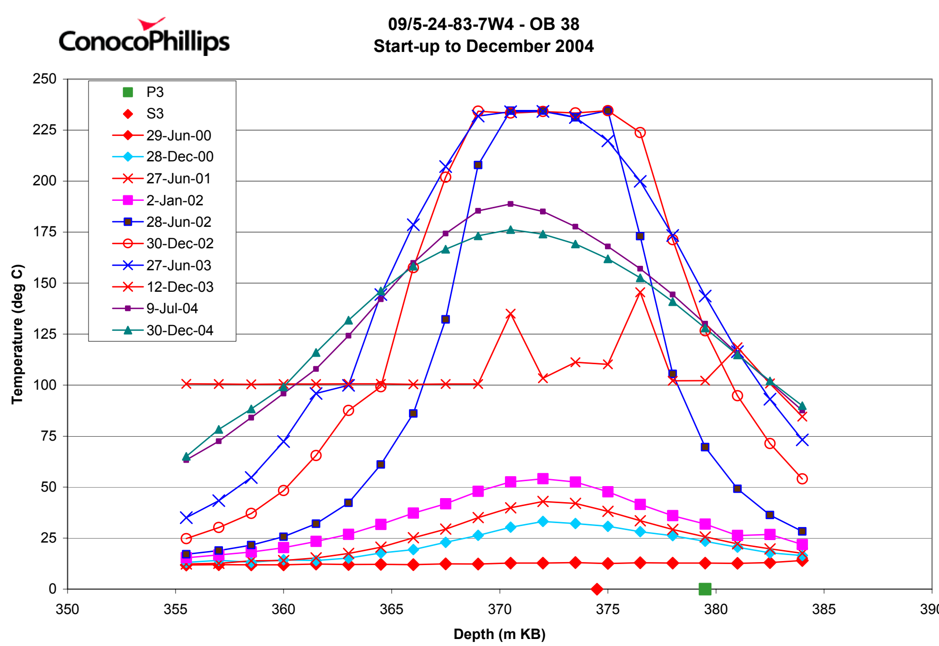


There are three piezometers installed in the bitumen at the OB 26A well. The two lower most piezometers, which are 6 and 20 m above the level of the injection well exhibited pressure responses to steam injection pressures, as illustrated in the plot that follows.



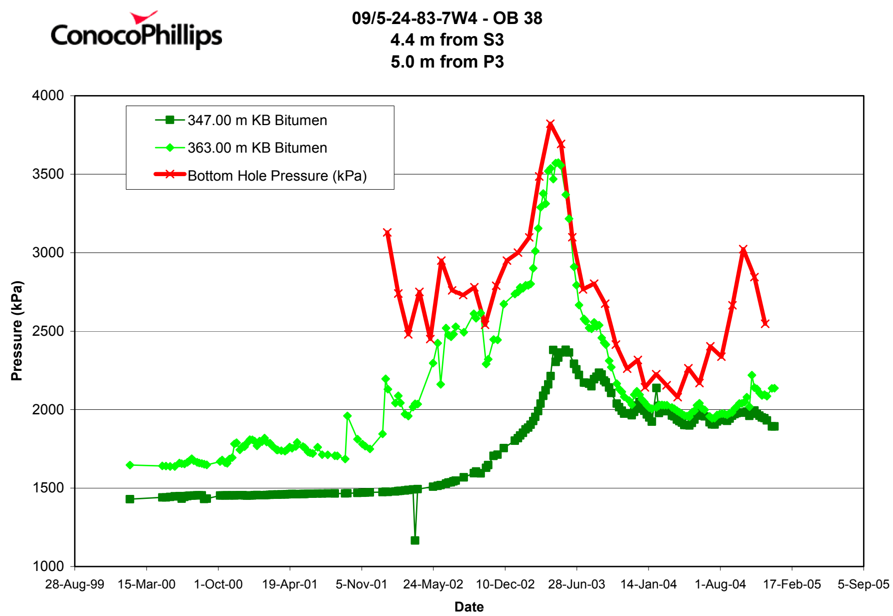
3.3.10 OB 38 (109/5-24-83-07 W4M)

Lateral separation of the OB 38 well is 4.4 m from S-3 and 5.0 m from P-3. This well is located ¾ of the way down the trajectory of the S3/P3 horizontal well pair. This well was displaying the lowest temperature response until April 2002. However, between April 2002 to October 2003 the OB 38 thermocouple data had been indicating the presence of a steam chamber. The thermocouple string was pulled in December 2003 due to a possible casing leak at this well. In June 2004 the thermocouple string was re-installed after



confirming the casing intergrity. The July and December temperature profiles indicate that the steam chamber has continued to fall back at this location and that conduction heating is occurring

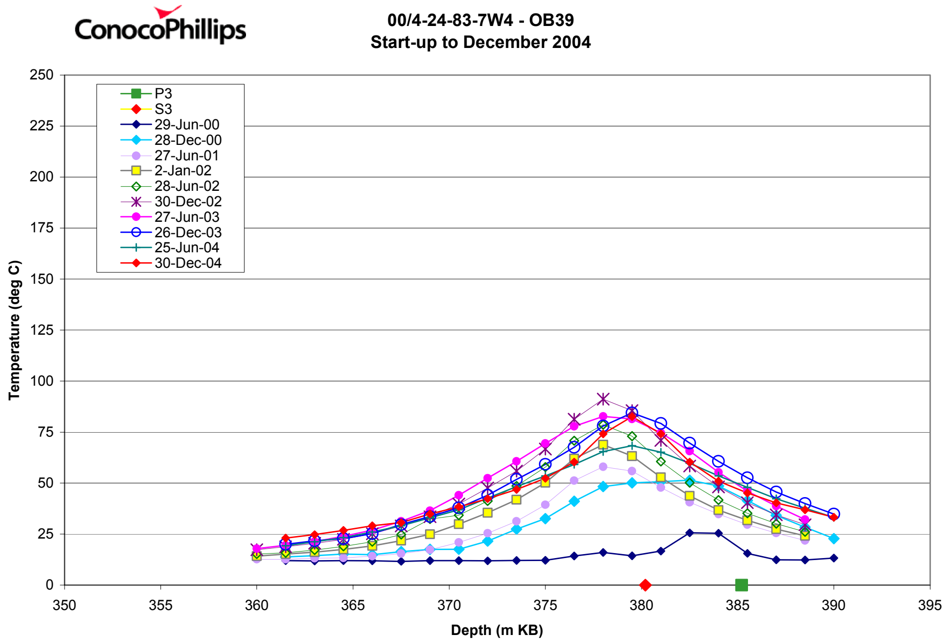
There are two piezometers installed in the bitumen zone at the OB 38 well, one at 363 m KB and one at 347 m KB. Both these piezometers, which are 12 and 29 m above the level of the injection well, are exhibiting a pressure response to the steam injection pressure.

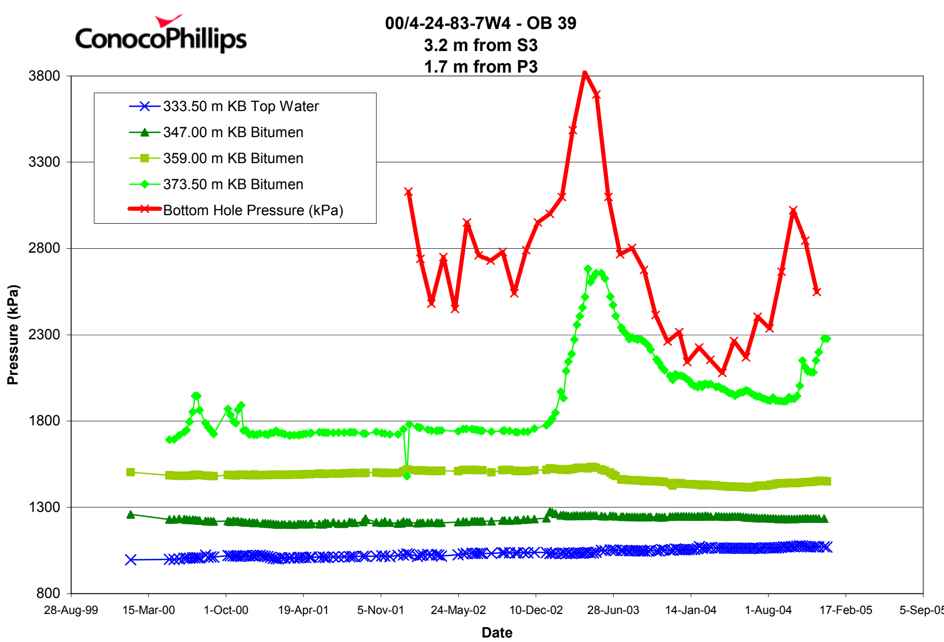


3.3.11 OB 39 (100/4-24-83-07 W4M)

The OB 39 well is at the end of the S3/P3 horizontal well pair. Lateral separation is 3.2 m from S3 and 1.8 m from P3. Although this observation well is the closest well to the horizontal well pair, it is not exhibiting a steam chamber. This well did initially exhibit a temperature response due to conduction heating but has not developed a steam chamber due to the presence of mudstone between the injector and producer as illustrated by the log section in the 2001 report.

There are four piezometers installed at the OB 39 well, one in the top water zone and three in the bitumen zone. The three in the bitumen zone are installed at 347.0 m KB, 359.0 m KB and 373.5 m KB. The lower most piezometer, at 7 m above the injector showed the most pronounced pressure response while the middle bitumen piezometer exhibited a small response.


ConocoPhillips
00/4-24-83-7W4 - OB39
Start-up to December 2004
P3
S3
29-Jun-00
28-Dec-00
27-Jun-01
2-Jan-02
28-Jun-02
30-Dec-02
27-Jun-03
26-Dec-03
25-Jun-04
30-Dec-04
Temperature (deg C)
Depth (m KB)

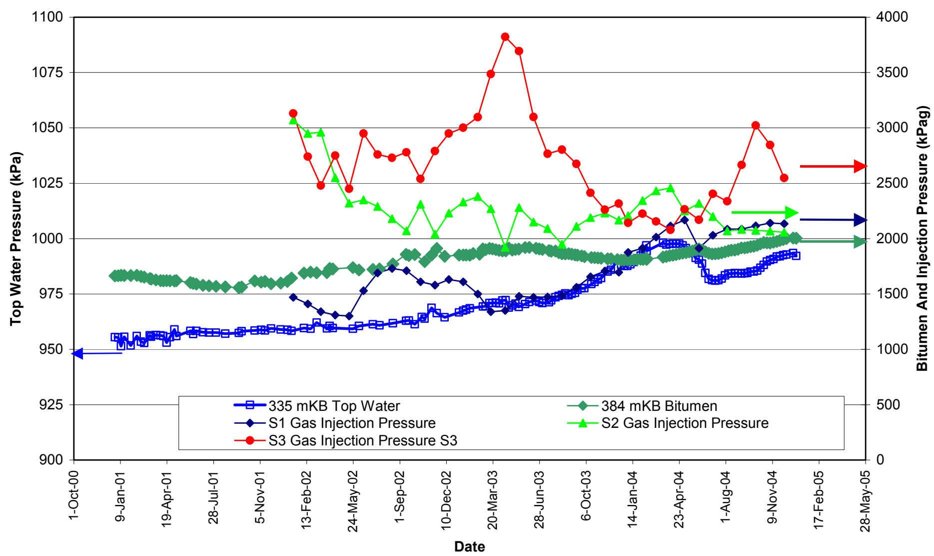

ConocoPhillips
00/4-24-83-7W4 - OB 39
3.2 m from S3
1.7 m from P3
333.50 m KB Top Water
347.00 m KB Bitumen
359.00 m KB Bitumen
373.50 m KB Bitumen
Bottom Hole Pressure (kPa)
Pressure (kPa)
Date

3.3.12 OB 25 (102/5-24-83-07 W4M)

OB 25 is located between the S1 and S3 horizontal injectors. The piezometer in the bitumen zone of the OB 25 well indicates that the pressures in the bitumen zone were as high as 2000 kPa during the reporting period. These pressures indicate the pressure wave from the steam chamber. The pressure exhibited by top water piezometer at 335 m KB over the last year appears to be following the steam injection pressures.

ConocoPhillips

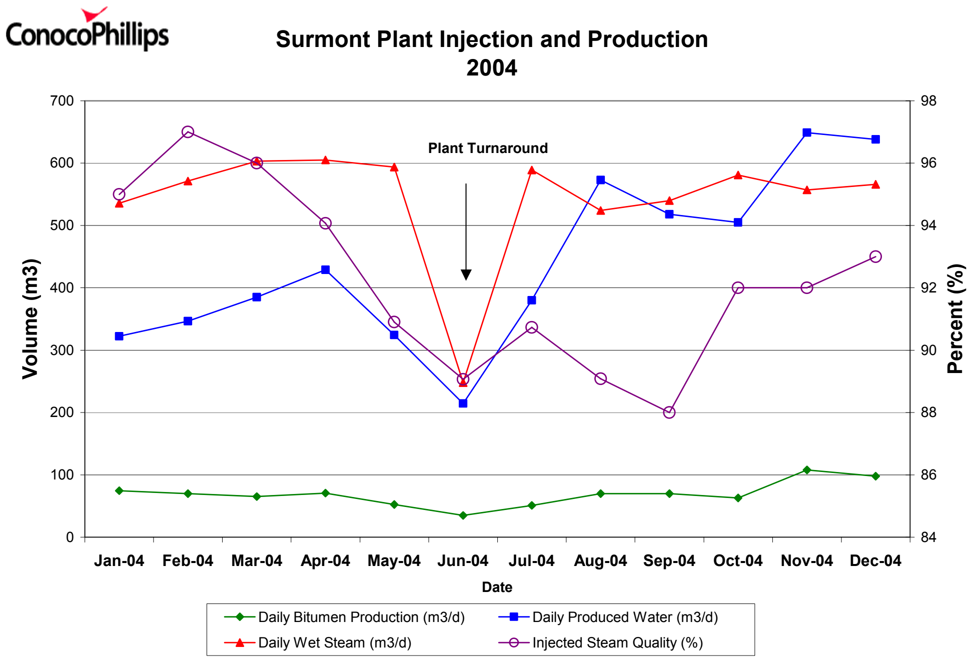
02/5-24-83-7W4 - OB 25
Bitumen Piezometer and S1 and S3 Gas Injection
December 2001 - December 2004



4 Pilot Performance

4.1 Injection and Production History

The 2004 Surmont pilot performance, with regard to steam injection rates, bitumen and water production rates, and steam oil ratio are provided graphically. The graphs show monthly averaged data.



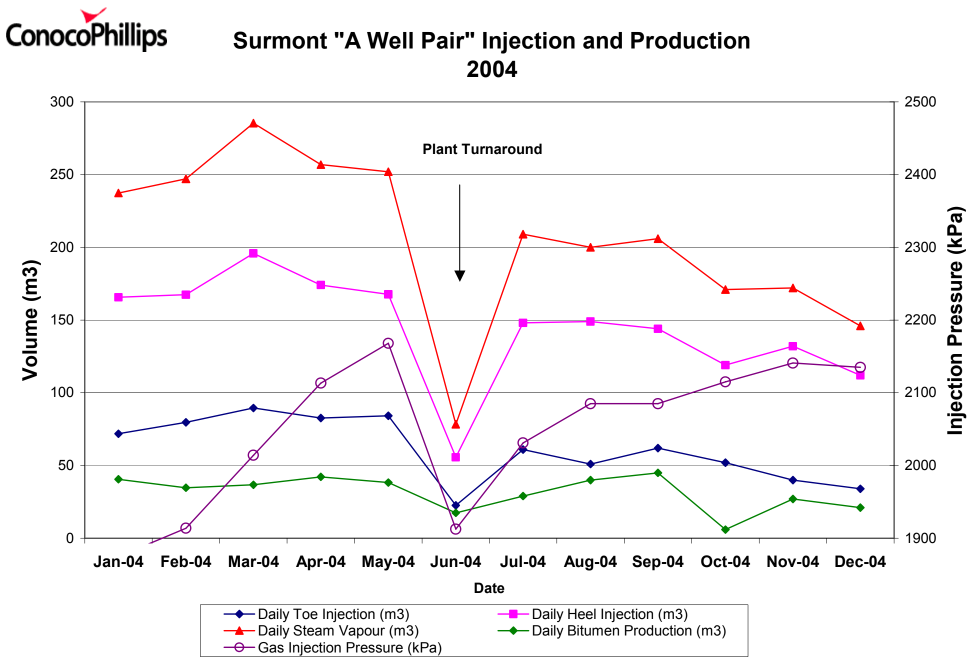
Plots from the individual P1, P2 and P3 production wells are provided for the year 2004. An allocation method to balance the liquid production from tank inventory changes with the mass flow meter readings of individual wells is being utilized. The total bitumen production from the Surmont pilot project is consistent with trucked dilbit sales volumes minus the diluent volumes. This total bitumen production reporting is considered to be the most accurate account of the production from the operation.

The total water production is the difference between metered water disposal rates and metered blowdown water rates (from the steam generator).

Total project steam injection is calculated from the boiler feed water minus the blowdown water, and then allocated to the individual wells based on the individual steam meters. Steam quality is the same for all injection wells and is estimated based on the ratio of blow down water to boiler feed water, i.e., when the blow down separator is fully operational, then near 100% quality steam is injected at the wellhead.

4.1.1 A (P1/S1)

During 2004 the A well pair (P1/S1) operating pressure was being increased. The following plot illustrates that the gas injection pressure was increased from 1875 to 2135 kPa.



The previous figure shows the distribution of steam to the toe and heel of the injector. The distribution of steam remained mostly to the heel to improve steam quality distribution by avoiding associated higher pressure drops within the smaller toe tubing string.

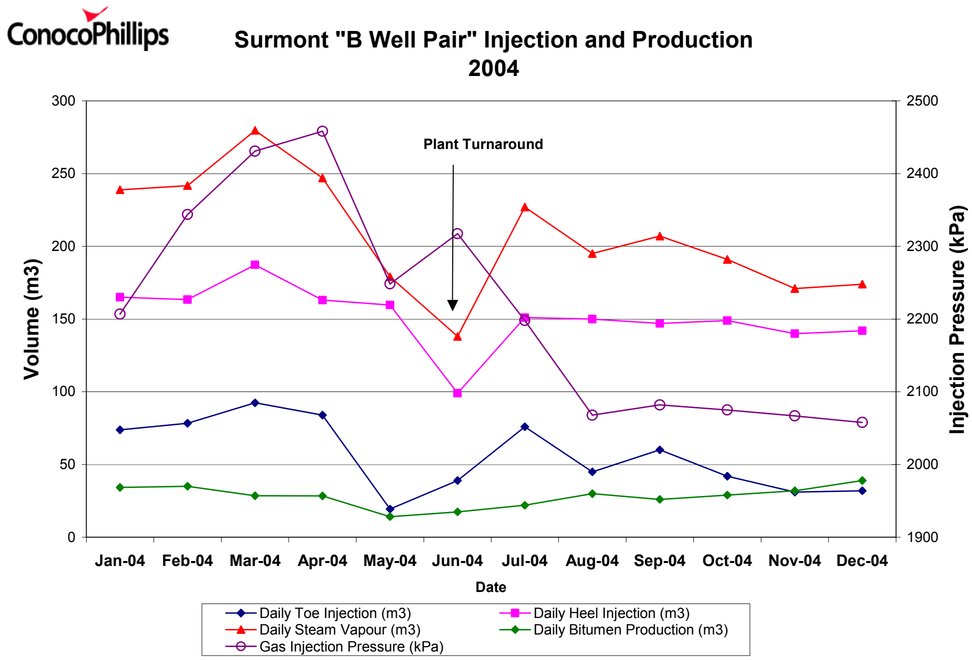
The A well pair steam chamber pressure is based on the casing blanket gas pressure at S1. Short-term injector shut-ins were conducted to verify actual reservoir pressure.

Wellbore subcools are calculated from the difference between the steam saturation temperature calculated from the measured producer wellbore pressure and the measured temperature. This indicates how close the water entering the pump is to flashing conditions. Due to the failure of the portion of the downhole Promore gauges producing wellbore subcools weren't available for most of 2004. During the June 2004 turnaround the Promore ERD device was replaced only to have the pressure measurement portion of the device fail in August, leaving left only temperature measurements. Reservoir subcools remained between 25-35 °C.

Annual bitumen production averaged 32 m^3/d. This rate is reasonable given the operating pressure was building for most of the year. As a result of increasing pressure via increasing the volume of steam injected the SOR for 2004 was 5.9.

4.1.2 B (P2/S2)

For the first part of 2004 the strategy for the B (P2/S2) well pair was to continue increasing the operating pressure to re-establish steam rise. As a result dry steam injection rates at S2 were increased to over 250 m3/d starting in March 2004, subsequent to the production rate decrease that was initiated in late 2003.

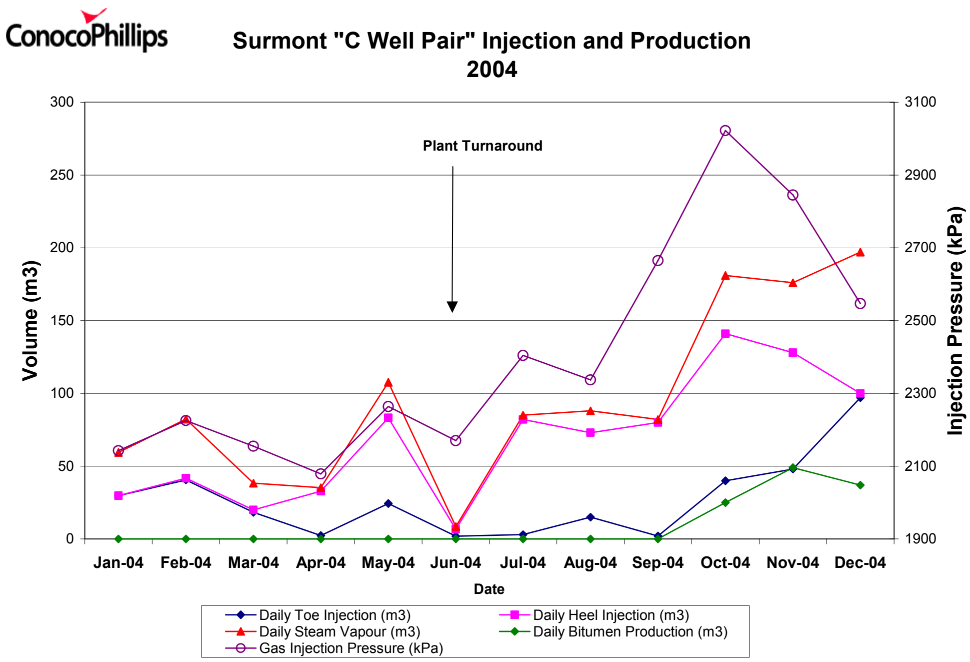


Distribution of steam to the toe was limited by pressure drop constraints down the small diameter toe string with the remainder down the heel. Due to high horizontal wellbore skin, steam chamber pressures were approximately 500 kPa lower than the S2 gas blanket injection pressure indicates. By August 2004 these skin effects lessened and the S2 blanket gas pressure became more representative of reservoir pressure. Short-term injector shut-ins were conducted to verify actual reservoir pressure. Production was relatively stable in 2004, with bitumen production rates at an average of 28 m^3/d with a high average dry SOR of 6.75, again due to increasing chamber pressure. The reservoir subcools at P2 remained relatively constant in the 20-25 °C range after turnaround.

4.1.3 C (P3/S3)

The principal purpose of the new 700 m C well pair (P3/S3) was to develop the technology for start-up and operation of a commercial length SAGD. Lifting the production by only using an ESP from day one was thought to have the potential advantage of:

- Reducing the process overall SOR
- Limiting the surface equipment and allowing better heat recovery



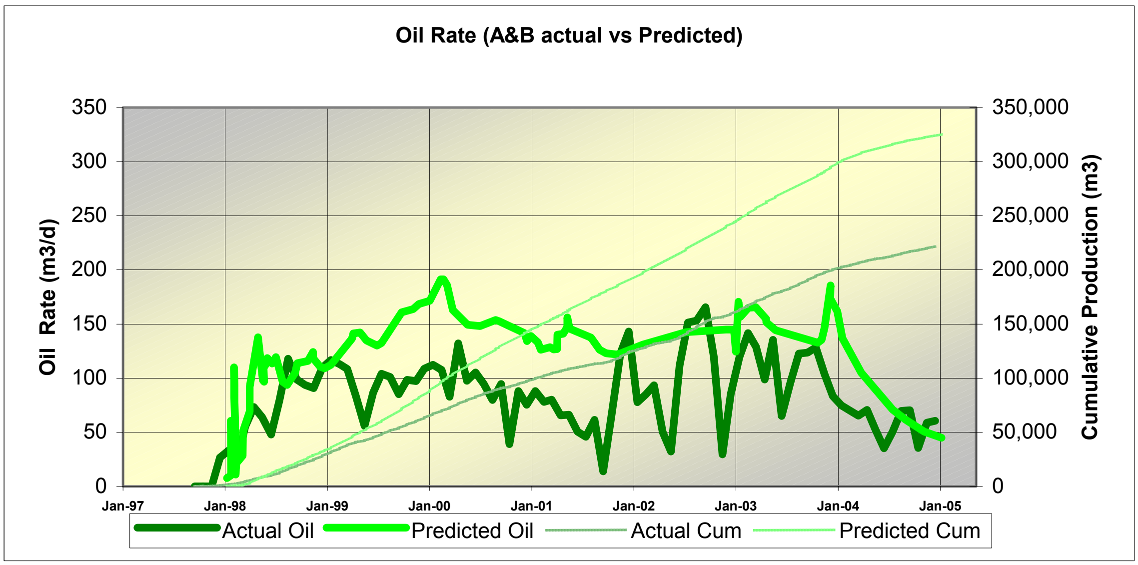
Initially P3 was equipped with an ESP and SAGD production was initiated mid-December 2000. In December 2001, following a third ESP failure, it was decided to abandon the ESP's and was replaced with a gas/steam lift system.

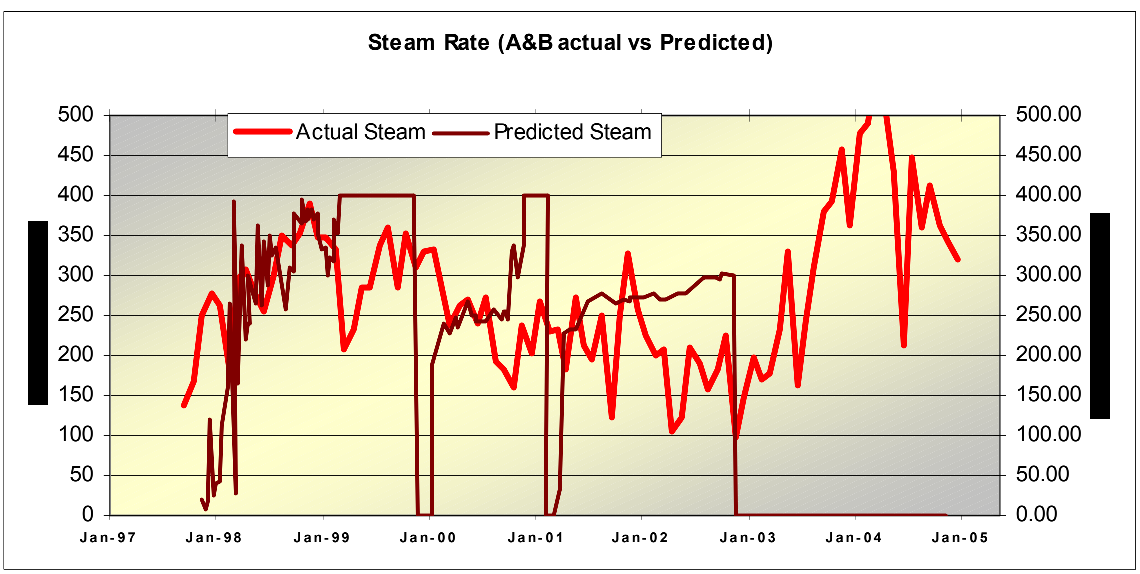
Due to steam limitations the operating pressure at C well pair continued to decline and production was shut-in in November 2003 when the gas lift system would no longer function at lower reservoir pressures (approximately 2200 kPa). A new pumping system was scheduled for installation and testing in early 2004, however development/testing problems caused a significant delay in pump delivery. During 2004 all excess steam was diverted to the C well pair. After the A well pair workover and resuming C well pair production in October injected steam volumes increased from 59 to 197 m^3/d and resulted in increased steam chamber pressures.

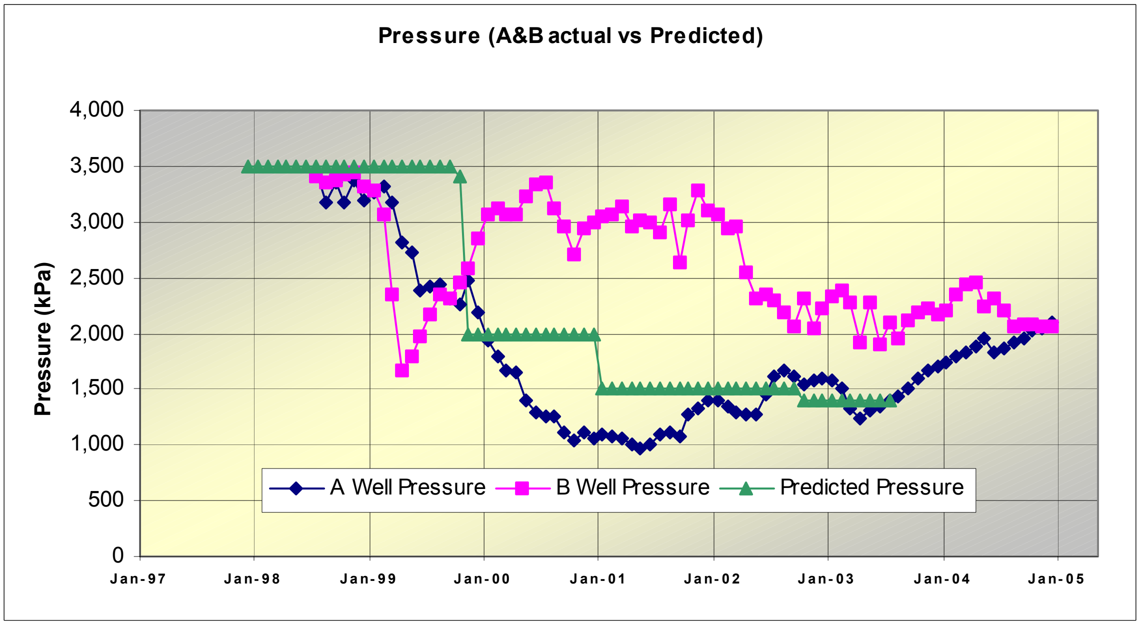
Bitumen production was resumed in October 2004 when a rod pump was installed in the P3 well. Bitumen production averaged only 37 m3/d for the last 3 months of 2004 with an average SOR of 4.60. After a change in heel/toe steam distribution, reservoir subcools dropped into the 10-15^{o} C range.

4.2 Comparison of Predicted versus Actual Performance

A comparison of predicted versus actual performance is provided for the combined injection and production of the P1/S1 and P2/S2 well pairs. The predicted performance is shown below.







The simulation prediction was first submitted to the gas/bitumen inquiry in 1997 as Figure 5, Case 1, in the report entitled "Reservoir Study Concerning the Effect of Thief Zones on Recovery Performance at Gulf's Surmont Oil Sand Leases". The report was re-submitted in the 2000 Resource Management Report as Attachment #2. The model was built from the general geology for the area.

The effective startup date for the Surmont pilot project is considered to be January 1998. This is the estimated equivalent startup date had the wells not experienced the numerous operational difficulties in 1997 and the re-completion downtime in February 1998. The 350 m long A well and the 350 m long B well may be compared to the prediction for a 700 m long well in the case cited above.

Cumulative Comparison

	2003	2003 *	2004	2004
	Predicted A & B Combined	Actual A & B Combined	Predicted A & B Combined	Actual A & B Combined
Avg Oil Rate (m3/d)	136	91	45	87
Cum Oil (e3m3)	298	200	325	222
Cum Dry SOR	1.7	2.6	1.5	2.9

*** An error was discovered in last year's volume calculations in this section of the report. The correct volumes are reported in the table above.**

The comparison of predicted oil rate, cumulative oil and cumulative SOR is not a exact comparison since the original prediction does not match actual operating pressures and/or allow for downtime or lift experimentation. The actual operating pressures in the field have been adjusted to achieve experimental objectives. Furthermore, operational issues have dominated the process. Although average performance is poorer than predicted, the plots illustrate that when operational issues are minimized the performance is in line with the predicted. The predicted cumulative SOR is significantly lower than actual since it was assumed that the well pairs would be in blowdown mode by now. Actual data suggests that normal operations should continue into the foreseeable future.

The C well pair performance was affected by the low pressure start-up which was proven to be inefficient, numerous ESP failures in 2001, narrow slots restricting flow in the production well and the continuing lack of steam due to plant capacity limitations throughout 2003 and into 2004. Additionally, C well pair was shut in for the majority of 2004. Due to this long non-productive period a large amount of accumulated water will have to be produced off before normal production performance can resume.

5 ARTIFICIAL LIFT

The artificial lift systems installed in the wells throughout 2004 Sucker Rod Pumps (SRP) in P1, and P2, and after October 2004 in P3.

The operating strategy for 2004 was to increase the pressures in A and B in an attempt to continue steam chamber growth and observe and monitor steam chamber development as a function of pressure. As such, it was necessary to restrict production during this time to assist the pressure development. This restriction and increased steam injection caused the cumulative SOR to climb to 3.2 by the end of the year, whereas it had been below 3.0 previously. Well pairs A and B were operated at the same pressure since it was believed their associated steam chambers could be communicating.

5.1 P1 (107/05-24-83-07W4)

The tubing pump failed from normal wear in May after a long run life since November 2002. A tubing pump was put in as a replacement but subsequently failed in June. The pump teardown failed to discern the cause, though it was agreed that the pump had not been torqued properly resulting in the cage coming loose from the rest of the pump. A replacement 4.75" tubing barrel pump was installed.

In August, there was a minor workover to replace the polish rod, which was slightly bent and causing some problems with leakage around the stuffing box. At this time, the downhole pressure measurement device (Promore ERD) malfunctioned and left only temperature measurements until the next workover was completed in October. Reservoir subcools remained in the range of 25-35^{o} C.

The surface drive Ecoquip unit was changed out for a few weeks in September with a smaller version with limited capacity to enable servicing and was returned to the original design when the service rig was on site for other work.

The pump installed in June failed in October 2004 likely due to a quick over pressuring of the flow line and suspected blowing of bottom hole drain. Given that there was no longer the steam requirement at this well, the high cost for a tubing pump and recent difficulties with these pumps, a 3.25" insert pump was installed.

5.2 P2 (108/12-24-83-07W4)

Dynamometer cards indicated a problem with the P2 well and the pump subsequently failed in May. The pump teardown determined the cause of failure to be wear, particularly on the traveling valve. The pump had been running since May 2003 and was using a 3.25" insert type pump. In September, the Lufkin pump jack had to be re-aligned by Weatherford so that the polish rod was stroking straight

Reservoir subcools were also quite constant after turnaround in the 20-25^{o}C range.

5.3 P3 (AA/04-24-83-07W4)

In 2003, sufficient steam chamber pressure was lost in C well pair such that gas lift was no longer able to function. P3 did not produce until a SRP was installed in October 2004.

The surface drive for the P3 SRP is a Weatherford VSH2 hydraulic pumping unit that uses nitrogen to push down on the accumulator to help drive the rods. A 4.75" tubing pump was installed downhole. Later in October, a minor workover was needed to change out the polish rod since it was leaking too much from the stuffing box. The workover revealed the previous polish rod was not fully spray coated and was upside down. The downhole spacing was also adjusted during this time.

To assist in analysis and troublshooting, a pump-off controller was installed with radio communication back to a laptop at the Pilot Plant. Due to some electrical difficulties this had only moderate success and was not used to the best of its capabilities.

Reservoir subcools were quite high upon initial start up, 50^{o}C and above. After a change in heel/toe steam distribution, reservoir subcools dropped into the 10-15^{o} C range.

6 GEOPHYSICS

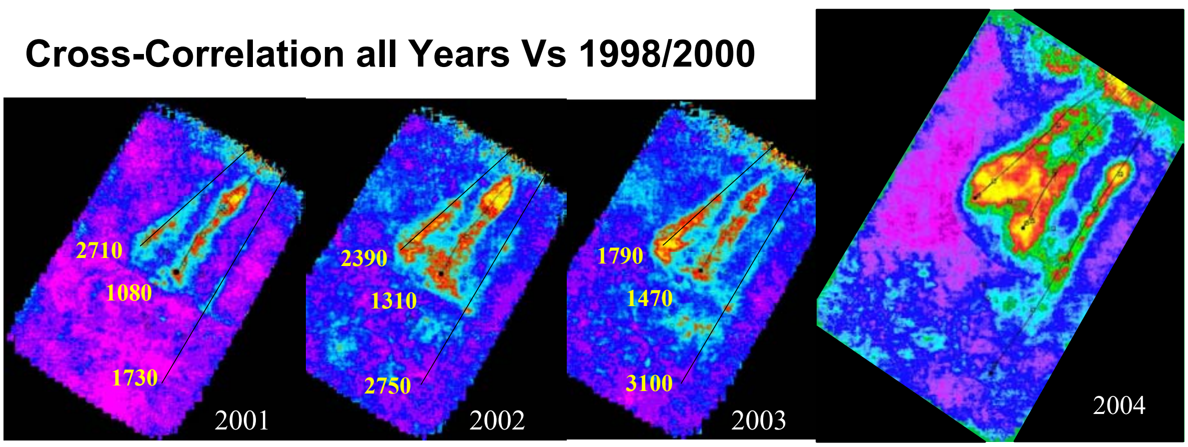
A description of ConocoPhillips Canada's 2D and 3D seismic is included in the "Surmont Oil Sands Leases" section of the Resource Management Report.

6.1 Pilot Area Time Lapse Seismic

The 4D seismic is used to monitor development of the steam chamber around the injection wells. The seismic data responds to the development of the steam chambers and should be useful for predicting breakthrough into overlying thief zones, as well as interaction between adjacent steam chambers.

For the current reporting period the June 2004 seismic data has been incorporated with the previous 6 years of seismic data and the map view of the steam chambers has been updated. The images that follow illustrate in map view the effects related to steam. Note that the difference baseline is extended for the 2003 analysis, using 1998 for the northern area and 2000 for the southern portion of the "C" well pair.

The 2004 data indicate that the shorter well pairs' (A & B) steam chambers are connected seismically and the longer (C) well pair's chamber is growing. The numbers on the map view pictures are the operating pressures in kPa.



6.2 Conclusion

The 4D seismic continues to show affected areas at all three well pairs. Additional well data is continually acquired to better calibrate the seismic analysis and to assist with 4D visualization of steam chamber development.

7 GEOLOGY

There are no new geological data to report for 2003.

8 INTERPRETATIONS

This section provides interpretations and conclusions based on the year 2004 data presented in previous sections.

8.1 Steam Chamber Development

The following topics address steam chamber development in the A, B and C well pairs during the year 2004.

8.1.1 A and B Well pairs

Observation Wells

1. **OB 22 Temperature Data**

In 2000 the overall steam rise rate averaged 8 m/yr through a heterogeneous region containing mudstone breccia, and silty shale layers. The rise of the steam chamber was delayed by 4 months due to a 0.6 m thick shale layer. This provided an important direct field demonstration that heterogeneities in the McMurray formation act like baffles, and not barriers.

During 2001, the steam chamber in observation well OB 22 continued to rise, as previously predicted. The steam rise rate averaged 6 m/year through a fairly clean sand region.

The relatively good steam rise performance in OB 22 during these previous years occurred despite several factors:

- The apparent reduction in the height of the steam chamber by one half starting in November 1998 as the steam chamber was depressurized. The top of the steam chamber did not recover to its former elevation until November 1999.
- There were non-optimum subcool values in P2, due to insufficient lift.
- High-quality steam may not have reached the toe of S2. (Where OB 22 is located)
- In 2001, the S2 injection rates were restricted due to plant limitations.

During 2002, the apparent top of the steam chamber had dropped, similar to what occurred at the end of 1998 when the pressure in the steam chamber was reduced. Steam chamber development has been sensitive to operating parameters such as lowering operating pressures and lift.

In 2003, steam chamber pressures were down slightly and then up slightly, so the apparent top of the steam chamber remained at about the same position.

During 2004, the increased S2 injection rate corresponded to steam chamber growth and development. Thermocouple data at OB 22 indicated that the chamber grew 17 m in 2004. By the end of 2004 the temperature at the thief zone interface was above 100°C and in a potentially mobile state.

2. Other Observation Well Temperature Data

Lift and operating pressures are among the factors that can affect overall steam chamber growth rates. Steam chamber shape is affected by geologic variations along the well pair, operational issues including high subcools and steam rate and quality distribution issues that can favour the growth of the steam chamber in one area.

In 2004, the lack of steam chamber development at OB 17 and its erratic behavior at OB 36 is considered to be primarily due to the following operational factors:

- The tailpipe configurations in P1 and P2, which forces flow from the heel to the toe, makes production from the heel of the wells (OB 41 and OB 17 locations) susceptible to any potential plugging/or flow restriction.
- Pressure cycling

Increased steam injection rates in A and B pairs did result in increased temperatures in all the wells. OB 17 did see a significant temperature increase, although not at steam conditions this response does indicate that chamber development is closely tied to operational conditions. OB 36 did experience chamber development and a temperature response can be implied with further analysis at OB 24 despite not having thermocouples lower in the bitumen zone.

Bitumen Recovery

To recover the bitumen from the upper McMurray it will have to come in contact with steam. Since the top of the steam chamber is not level, successful SAGD operations continuing after communication with the top thief zones are required in order to maximize bitumen recovery.

The bitumen recovery obtained in the A (P1/S1) and B (P2/S2) well pairs during 2004, at an average rate of 60 m^3/d, a significant 53% decrease from the previous year. This decreased production rate can be associated with the process of increasing the reservoir pressure of A and B pairs to approximately 2000 kPa and to a lesser extent to operational issues. The bitumen rates are slightly lower than predicted numerically, as described previously. To the end of 2004, on a cumulative basis, ConocoPhillips delivered 272,000 m^3 of bitumen from the plant of which 221,500 m^3 of the total was from the two original 350 m long A and B well pairs.

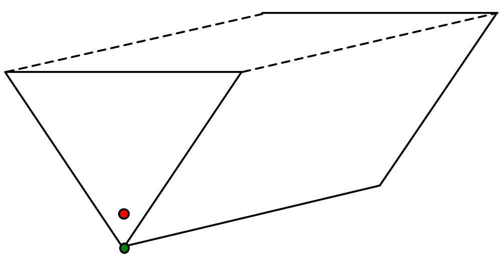
Total Volume of Steam Chamber

The A well cumulative bitumen volume was 94,200m^3 and the B well cumulative bitumen volume was 127,300m^3. For an average porosity of 0.30 and an average reduction in bitumen saturation of 0.70 within the steam chamber (at this stage of steam chamber development), the total volume of the A and B steam chambers was 448,000m^3 and 607,000m^3, which is a total of 1,055,000 m^3 respectively at the end of 2004.

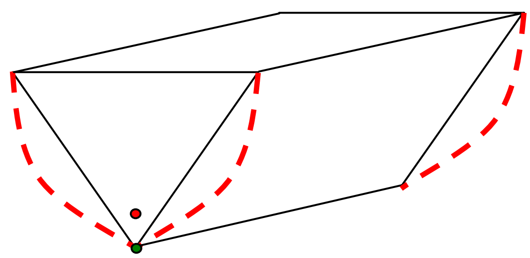
If the average porosity were less than 0.30, and/or if the average change in bitumen saturation within the steam chamber were less than 0.70, the steam chamber volume would be greater than 1,055,000 m^3.

Approximate Dimensions of Steam Chamber

When calculating the steam chamber dimensions more detailed considerations were made for this report. The previous method to calculate steam chamber volume/dimension assumed a triangular chamber shape and a completely uniform vertical dimension along the horizontal length of each well. It is known from simulation results that the shape is not necessarily triangular. It is also known from observation well data that the steam chambers are not necessarily uniform along the horizontal direction. The observation well data also indicates the height of the steam chamber at those points. Taking these facts into account better estimate of the steam chamber volume and its dimensions can be made.



Previous Shape Assumption



New Shape Assumption

Using the following assumptions the approximate shape of the steam chamber in the A and B well pairs can be calculated at the end of 2004:

- A well chamber is uniform along the well length and has an average height of 15 m above the producer
- B well chamber is not uniform length (approximately 70% ot total length) and has an average height of 40 m above the producer

Given these assumptions of chamber length and height, the width can then easily be determined. The average dimensions of the A and B steam chambers at the end of 2004 are estimated as follows: A well pair's chamber is 15 m high, 114 m wide and 350 m long, and B well pair's chamber is 40 m high, 82 m wide and 245 m long.

The continued bitumen production and large estimated steam chamber size continue to show that SAGD operations below a thief zone are feasible.

8.1.2 C Well pair

C well production was shut in from November 2003 to October 2004 with limited steam injection continuing. When production resumed the steam chambers at OB 26a and OB 38 had collapsed and only a conductive zone remained. Interestingly, the observation wells towards the heel of C pair, OB 37 and OB 20, incurred new chamber growth.

- OB 20 approximately 0 m from P3/S3 heel – 8.5 m lateral distance
- OB 37 approximately 175 m from P3/S3 heel – 4.5 m lateral distance

Over 10 m of new steam chamber growth was seen at OB 20. This chamber growth occurred despite a lack of production withdrawal and then accelerated when production started.

OB 39 at the Toe exhibited conduction heating responses only. The steam chamber does not have a regular shape and the lack of steam development at these locations can be explained by the poorer reservoir quality especially at OBS 39. If the horizontal wellbores are placed in poorer quality pay there will be less oil drainage and a correspondingly smaller steam chamber size.

8.2 Effect of Overlying Gas Zone on Bitumen Recovery

Hydraulic communication of the steam chamber(s) with the overlying water and gas zones became evident during 2003 and continued into 2004. The pressure increases in the thief zones along the A and B well pairs have been relatively small. During 2004, higher temperatures have been observed at the thief zone interface and to date there does not seem to be any negative impact on production performance. Since the pilot test is ongoing, the effect of the thief zone on ultimate reserves recovery remains unknown. There has been a much larger pressure increase in the upper bitumen zones underlying the thief zones along the C well pair. However, since the P3 well is no longer capable of producing with gas lift, any effects on recovery from pressure communication with the thief zones will not be known until the well's production is resumed.

8.3 Overall Success of Pilot

8.3.1 Bitumen Production

During 2004, the average bitumen production rate of 60 m^3/d from the two half-length well pairs is a significant decrease from the 2003 record high of 111m^3/d. This reduction can be associated with two things: the re-pressurizing of the A and B chambers to 2000 kPa and to several artificial lift problems and insufficiencies. Additional factors not accounted for in the original commercial predictions were well pair or plant downtime. Since the pilot does not have the built in redundancy that a commercial plant would, the downtime effects are greater. Also a pilot is operated in test mode, rather than a commercial operation mode that will affect average performance. Actual production would be even closer to the commercial predictions if adjusted for downtime.

The A and B average SOR of 6.9 for 2004 was a reflection of the poorer performance. The original prediction assumed blowdown by the 6^{th} year of operation while actual operations are expected to continue for the foreseeable future. The cumulative SOR for the A and B well pairs has risen to 2.92 by the end of 2004.

By the end of 2004, the total trucked sales bitumen was 272,000 m^3. The 221,000 m^3 of bitumen production from the A and B well pairs translates to a volume of the steam chamber of at least 1055,000 m^3, or a semi-triangular steam chamber averaging 545 m in length, 98m in width, and 26 m in height. This large steam chamber size is bottom-line proof that the steam chambers' growth through and/or around interbedded heterogeneities act only as baffles and not barriers.

To determine the overall impact of SAGD performance under a thief zone, the recovery following thief zone interaction needs to be maximized, but so does the recovery prior to thief zone interaction. The recovery factor in the A and B well pairs has already reached 20.3% of the OOIP, and is well on its way to achieving commercial recovery factors.

8.3.2 Steam Rise Data

P1/S1 and P2/S2 well pairs

During the year 2001, OB 22 has demonstrated a relatively good steam rise rate of 6 m/yr through a fairly clean sand section of the formation. Most importantly, it was demonstrated in November and December 2001 that the yearly average rise would have been even better with adequate lift and good steam quality at the toe of the injection well. During the last two months of 2001, the average steam rise rate was restored to 12 m/yr. The evidence provided by OB 22 is a very important demonstration of steam rise through and/or around heterogeneities in the McMurray formation. Reducing the operating pressure in preparation for interaction with the thief zones resulted in the apparent drop of the steam chamber height. This apparent drop in the steam chamber height stabilized during 2003 and may be due to an accumulation of non-condensable gas or fluid drainage at this location as the pressure in the steam chamber was reduced. In 2004 the chamber grew significantly, growing 17 m within the year at OB 22. Although, it should be noted that the steam chamber response observed at OB 22 seems to indicate that the chamber growth near the top appeared to come in laterally across OB 22. To fully recover the bitumen from the upper McMurray, contact with steam is necessary. Since the top of the steam chamber will not be level, successful SAGD operations continuing after communication with the top thief zones is required to maximize bitumen recovery.

The pilot has also demonstrated that the limited steam chamber development at OB 36 and OB 41 can be linked to operating conditions (pressure, lift, steam rate and quality). Vertical chamber growth was minimal in 2004, approximately 1-2m.

P3/S3 Well pair

The C well pair was shut in for much of 2004. Prior to being shut-in, the steam chamber was present along the middle portion of the horizontal length, namely OB 26a and OB 38. When production resumed in late 2004 the steam chamber seemed to shift toward the heel portion of the well. OB 20 at the heel position incurred the most steam chamber growth in 2004 in excess of 9 meters.

8.3.3 Communication with Thief Zone

Hydraulic communication between the steam chamber(s) and the overlying thief zone had been firmly established in 2003. This has been seen from the pressure data at OB 24 and OB 36 along the A well pair. More significant pressure increases have been seen 10-15 m ahead of the steam front at the piezometers located high in the bitumen zone at OB 20, OB 37, and OB 38 along the C well pair indicating fluid displacement high into the bitumen zone appearing well in advance of any observed temperature response. These pressure responses appeared only after the C well pair steam chamber was pressured up over 3800 kPa illustrating the large impact pressure has on the SAGD process. The pressure responses again illustrate that the heterogeneities in the McMurray formation at the Surmont pilot project act as baffles, not barriers.

By the end of 2004 OB 22 at the toe of B well pair was registering temperatures above 100° C at the reservoir/thief zone interface. At this temperature bitumen is mobile. To date, no negative impacts from this interaction have been observed on production performance. However, factors that have delayed breakthrough to the thief zone at the pilot project, compared to the numerical prediction, include the following:

- The impact of lowering the steam chamber pressure.
- Elevated subcool values due to insufficient lift at various times during the life of the well.
- Steam quality distribution difficulties in the injection.
- The SAGD process is significantly impacted by operational parameters

A better understanding of the apparent drop in the top of the steam chamber is required before a better estimate of temperature breakthrough to the thief zone can be made. Time to breakthrough is dependent on the lift conditions, the operating pressure, possible non-condensable gas accumulation and the degree of shale baffles. Meanwhile, reasonable production rates and recovery factors continue to demonstrate that the SAGD process is viable under thief zones. Post breakthrough success depends on operating the steam chamber at pressures slightly higher than the thief zone. This strategy balances heat losses into the thief zone against top water draining into steam chamber. Slower breakthrough times due to shale baffles should also decrease both heat losses into the thief zones and top water drainage into the steam chamber after breakthrough.

8.3.4 Tracers

ConocoPhillips utilized reservoir tracers in 2004 in the pilot wells in an attempt to understand potential communication of fluids between the various well pairs. The produced water sample data confirmed that there was fluid communication between the A and B well pairs.

8.3.5 Seismic

- 4D seismic shows interaction between all three pilot well pairs (especially at A and B well pairs)
- Additional data will be acquired to better calibrate the seismic analysis and to assist with 4D visualization of steam chamber development

9 Surmont Proposed Future Operating Plan

ConocoPhillips' operating plan remains aligned with pilot objectives as stated in Application No. 960817.

Both the A and B well pairs will remain the primary wells to determine the effect of a top water thief zone on the SAGD recovery process. As discussed in the previous report, the operating strategy for A and B well pair was to increase pressures to 2000 kPag. Now that pressure of approximately 2000 kPag is reached at A and B well pairs, C well will get any remaining steam.

There are no plans at this time to change the artificial lift systems in either of the A or B well pairs, although the tubing pump on A well pair was replaced with an insert pump. It is expected that an appropriate artificial lift system be installed in the C well in Q1 of 2005. Consideration is being given to installing a Can-K downhole twin screw in this well.

Although the main focus will be on the A and B well pairs, the operations through out 2005 will be adjusted accordingly to provide maximum reservoir data as well as optimizing the production from all the well pairs.

ConocoPhillips utilized reservoir tracers in 2004 in the pilot wells in an attempt to understand potential communication of fluids between the various well pairs. The data to date indicated that there is fluid communication between the A and B well pairs.

RST and temperature logs may be run again this year to verify and strengthen previous results. The tool does have some temperature limitations and the OB well environment definitely tests the limits when the wellbore is fluid filled. Results from the previous RST logs were encouraging.

Acquisition and analysis of 4D seismic data will be further utilized in 2005 to determine steam chamber development in the pilot area. Acquisition is tentatively scheduled for the spring.

Temperature and pressure data acquisition and analysis from the existing observation wells will continue.

Testing of various multiphase, water cut, and flow meters as well is expected to continue in 2005.