Innovative Energy Technologies Program

Project Approval No. 01-003
Final Report

June 30, 2012

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1. Report Abstract

The EnCAID project was designed to explore the use of air injection and downhole combustion to maintain formation pressure while accomplishing enhanced recovery of natural gas from shut-in "Gas Over Bitumen" (GOB) reservoirs. The project consisted of using a single air injection well in the Kirby K3 Wabiskaw gas pool to maintain the gas cap reservoir pressure and sweep gas to 6 existing production wells. A downhole combustion front was initiated and maintained to prevent oxygen from causing safety issues in the gas gathering system.

This Final Report summarizes the operational and financial results of the project, from the initiation of injection on June 2, 2006 thru the end of IETP funding December 31, 2010. The project went largely as planned despite some issues with plugging on the air injection well caused by compressor oil carry over. At the end of the reporting period a solvent squeeze on the injection well and coalescing filters downstream of the air compressors were planned to prevent the problem from reoccurring. Later in the reporting period, higher N2 production had to be restrained due to the lack of high heat value gas to blend the produced gas to sales specs. At the end of 2010 Cenovus was working on obtaining the necessary regulatory and partner approvals to bring on 4 additional producers at the far west end of the pool (referred to as EnCAID +). The drastic decline in natural gas prices over the project period significantly impacted project economics. The project demonstrated that this method for recovering GOB gas is technically sound and operationally viable. US and Canadian patent applications were submitted and were under review by the respective Patent Offices at the end of 2010.

Note: A Corporate entity change occurred on 2009-12-01 when Cenovus Energy Inc. split off from EnCana Corporation. Cenovus is referred to throughout this report.

2. Summary Project Status Report

2.1 Key Project Team Members

Larry Freeman – Production Engineer
Dr. Ben Nzekwu – Process & Reservoir Simulation
Julie Colwell – Reservoir Engineer
Dale Neufeld – Facilities Engineer
Larry Weiers – Vice President
Dr. Gordon Moore – Combustion Testing & Expertise
Ross Krill - Facility Engineering
Shelley Golebeski - Critical Controls and Monitoring design from Segment Engineering
Dr. Kenny Adegbesan - Reservoir Simulation with KADE
Jonah Resnick - Geologist for Geostatistical model for detailed history match
Scott Dutkiewicz, Ryan Samuel, Gary Joncas, Albert Whitford, Roger Boucher - Key Field Operating Staff during start up of EnCAID
Bill Hogue – Production Engineer
Kevin Cole – Geologist
Jessica Wu – Reservoir Engineer
Scott Obrigewitsch – Team Lead
Matt Toews – Reservoir Engineer
Dean Bierkos – Group Lead
Lee Emms – Facilities Engineer

2.2 <u>Chronological Report of All Activities and Operations Conducted</u>

- November, 2005: Alberta Department of Energy IETP 01-003 Approval
- January, 2006: ERCB Approval
- February, 2006: Spud 102/5-10-73-6W4 observation well
- June 2, 2006: Ignition & start-up
- January, 2007: Nitrogen response at 14-9-73-6W4Hz
- April, 2007: Nitrogen response at 2-16-73-6W4
- May, 2007: Nitrogen response at 11-15-73-6W4
- June, 2007: 14-9-73-6W4 Hz Shut in, Nitrogen >65%
- May, 2008: Nitrogen response at 1-17-73-6W4
- January, 2009: Gas production temporarily shut-in until 6-18-73-6W4 segregation repairs completed
- October, 2009: 1st decrease in injectivity
- June, 2009: Nitrogen response at 7-8-73-6W4Hz
- Q3 & Q4, 2009: 2-16-73-6W Colony flow test to try to cleanup cross flowed nitrogen from the Wabiskaw zone. Colony contaminated with nitrogen due to failure of surface check valve while flowing Wabiskaw & Colony during first 2 years of EnCAID.
- January, 2010: 100/5-10-73-6W4 injector stimulation treatment
- October, 2010: Shut in 1-17-73-6W4, Nitrogen 77%
- December, 2010: 100/5-10-73-6W4 air injection well fall off testing. Cenovus removed the thermocouple string and performed two pressure fall off tests on the EnCAID air injection well from December 12-21, 2010 and December 26-27, 2010. The data was analyzed to understand the wellbore damage which resulted from compressor lube oil carry over.
- December, 2010: Shut in 2-16-73-6W4, Nitrogen 84%
- December, 2010: Shut in 11-15-73-6W4, Nitrogen 70%

2.3 Production, Material and Energy Balance

The gross and net gas production history for the EnCAID project is shown in Table 2.3.1.

Table 2.3.1 Gas Production History

Month	Year	EnCAID Gross and Net Gas Production (e3m3)																
		7-8-73-6w4 Hz		2-16-73-6w4		14-9-73-6w4 Hz		11-15-73-6w4		1-17-73-6w4		6-5-73-6w4		6-10-73-6w4		Overall EnCAID		
		Avg Gross Gas	Avg Form Gas	Avg Gross Gas	Avg Form Gas	Avg Gross Gas	Avg Form Gas	Avg Gross Gas	Avg Form Gas	Avg Gross Gas	Avg Form Gas	Avg Gross Gas	Avg Form Gas	Avg Gross Gas	Avg Form Gas	Avg Gross Gas	Avg Form Gas	% Sales Gas
June	2006	667	667	422	422	729	729	147	147	211	211	225	225	12	12	2414	2414	100.0%
July	2006	626	626	443	443	622	622	269	269	381	381	0	0	9	9	2350	2350	100.0%
August	2006	589	589	244	244	810	810	178	178	377	377	0	0	3	3	2201	2201	100.0%
September	2006	738	738	435	435	788	788	268	268	269	269	0	0	0	0	2499	2499	100.0%
October	2006	763	763	448	448	819	819	316	316	227	227	74	74	0	0	2647	2647	100.0%
November	2006	746	746	444	444	802	802	311	311	216	216	0	0	0	0	2518	2518	100.0%
December	2006	711	711	408	408	772	772	297	297	255	255	0	0	0	0	2443	2443	100.0%
Totals	**2006**	**4840**	**4840**	**2844**	**2844**	**5342**	**5342**	**1786**	**1786**	**1936**	**1936**	**299**	**299**	**25**	**25**	**17072**	**17072**	**100.0%**
January	2007	778	778	458	458	838	808	318	318	150	150	0	0	0	0	2542	2512	98.8%
February	2007	691	691	442	442	654	542	330	330	207	207	0	0	0	0	2325	2213	95.2%
March	2007	721	721	429	429	681	442	413	413	123	123	0	0	0	0	2367	2129	89.9%
April	2007	757	757	450	450	715	417	443	443	140	140	0	0	0	0	2505	2207	88.1%
May	2007	785	785	463	440	541	227	455	409	318	318	0	0	0	0	2562	2180	85.1%
June	2007	771	771	457	379	152	104	444	398	397	397	0	0	0	0	2221	2049	92.3%
July	2007	809	809	295	206	0	0	451	356	414	414	274	274	0	0	2241	2058	91.8%
August	2007	825	825	207	114	0	0	453	291	423	423	329	329	0	0	2237	1982	88.6%
September	2007	802	802	136	62	11	2	367	209	413	413	319	319	0	0	2048	1807	88.2%
October	2007	834	834	87	31	3	0	257	100	432	432	331	331	0	0	1945	1728	88.8%
November	2007	813	813	127	31	0	0	304	120	422	422	322	322	0	0	1989	1708	85.9%
December	2007	743	743	105	29	0	0	258	97	387	387	292	292	0	0	1784	1547	86.7%
Totals	**2007**	**9329**	**9329**	**3656**	**3071**	**3594**	**2543**	**4493**	**3484**	**3827**	**3827**	**1866**	**1866**	**0**	**0**	**26765**	**24120**	**90.1%**
January	2008	744	744	74	19	12	2	273	70	438	438	334	334	0	0	1875	1606	85.7%
February	2008	778	778	90	22	0	0	147	37	411	411	218	218	0	0	1643	1465	89.2%
March	2008	749	743	120	20	2	0	169	45	424	421	235	235	0	0	1699	1464	86.1%
April	2008	849	849	131	16	0	0	90	24	446	441	248	248	0	0	1763	1578	89.5%
May	2008	878	878	134	17	0	0	89	23	461	457	258	258	0	0	1820	1633	89.7%
June	2008	853	853	115	13	0	0	86	20	450	435	250	250	0	0	1754	1570	89.5%
July	2008	883	883	133	10	0	0	89	17	464	412	259	259	0	0	1829	1581	86.4%
August	2008	892	892	133	9	2	0	89	18	462	363	259	259	0	0	1837	1542	83.9%
September	2008	817	817	115	8	14	0	83	20	424	299	238	238	0	0	1690	1383	81.8%
October	2008	901	901	123	8	24	0	88	20	465	304	262	262	0	0	1863	1495	80.2%
November	2008	875	875	137	8	0	0	83	18	453	276	254	254	0	0	1802	1430	79.4%
December	2008	794	794	108	5	2	0	55	13	408	145	230	230	0	0	1598	1187	74.3%
Totals	**2008**	**10013**	**10007**	**1412**	**157**	**56**	**3**	**1342**	**323**	**5305**	**4400**	**3044**	**3044**	**0**	**0**	**21173**	**17933**	**84.7%**
January	2009	509	509	68	3	1	0	45	9	276	131	156	156	0	0	1054	807	76.6%
February	2009	91	91	6	0	0	0	14	3	49	23	27	27	0	0	187	144	77.1%
March	2009	840	840	114	6	2	0	67	17	420	156	244	244	0	0	1688	1263	74.8%
April	2009	901	901	133	5	1	0	99	21	452	178	262	262	0	0	1847	1368	74.0%
May	2009	933	933	140	5	0	0	90	19	469	186	271	271	0	0	1903	1414	74.3%
June	2009	902	896	0	0	0	0	82	15	454	172	262	262	0	0	1700	1344	79.1%
July	2009	932	916	0	0	0	0	76	14	440	160	271	271	0	0	1719	1361	79.2%
August	2009	930	896	7	0	6	0	69	12	390	132	271	271	0	0	1673	1312	78.4%
September	2009	917	863	0	0	0	0	66	11	379	107	265	265	0	0	1627	1245	76.6%
October	2009	945	870	0	0	10	0	67	14	388	105	274	274	0	0	1684	1262	74.9%
November	2009	850	760	3	0	0	0	65	13	348	94	267	267	0	0	1534	1135	74.0%
December	2009	798	695	38	1	12	0	51	8	309	75	280	280	0	0	1488	1059	71.2%
Totals	**2009**	**9548**	**9169**	**508**	**21**	**31**	**0**	**791**	**155**	**4374**	**1519**	**2851**	**2851**	**0**	**0**	**18103**	**13714**	**75.8%**
January	2010	708	601	52	2	9	0	48	5	231	47	250	250	0	0	1297	905	69.8%
February	2010	712	593	83	3	0	0	53	5	224	43	252	252	0	0	1323	896	67.7%
March	2010	791	658	116	3	0	0	54	8	245	44	280	280	0	0	1486	994	66.9%
April	2010	766	608	96	2	0	0	53	9	223	40	271	271	0	0	1409	931	66.1%
May	2010	792	614	90	2	9	0	55	9	226	44	279	279	0	0	1452	948	65.3%
June	2010	768	590	66	2	0	0	56	9	133	26	272	272	0	0	1295	899	69.4%
July	2010	792	609	68	2	10	0	59	9	112	22	327	327	0	0	1368	969	70.8%
August	2010	648	473	9	0	0	0	8	1	7	1	274	274	0	0	946	750	79.2%
September	2010	733	527	37	1	5	0	59	12	45	4	377	377	0	0	1256	920	73.2%
October	2010	541	390	68	2	0	0	61	12	26	2	334	334	0	0	1029	741	72.0%
November	2010	512	362	67	2	0	0	30	6	0	0	285	285	0	0	893	655	73.4%
December	2010	585	410	37	1	0	0	39	8	0	0	200	200	0	0	861	620	72.0%
Totals	**2010**	**8345**	**6436**	**789**	**23**	**33**	**0**	**575**	**95**	**1472**	**273**	**3401**	**3401**	**0**	**0**	**14614**	**10228**	**70.0%**
Cumulative Total		**42076**	**39781**	**9208**	**6115**	**9057**	**7889**	**8988**	**5842**	**16913**	**11955**	**11461**	**11461**	**25**	**25**	**97728**	**83068**	**85.0%**

Energy and Material Balance

The following energy and mass streams apply to the EnCaid project:

- Steam, injected into the 100/5-10 injector to pre-heat the reservoir for ignition. Steam was injected at an average pressure of 4400 kPa and a quality of 77%.
- Compression energy; for in-situ combustion air injection. Compressors were run on natural gas (fuel gas).
- Produced Gases; both produced methane and produced combustion gases. Produced gases are not distinguished in the tables below, but an average heat content is used (based on frequent samples and lab tests).
- No liquids production occurred during EnCaid, no process air or fresh water was required, and negligible electricity was required (only for instruments and communications)

Table 2.3.2 Material Balance

	Year	Operating Volumes		Cumulative Material Balance <e3m3>		
Year		Daily Air Injection <e3m3/day>	Daily Gas Production <e3m3/day>	Cumulative Steam Injection (tons)	Cumulative Air Injection <e3m3>	Cumulative Gas Production <e3m3>
	Pre-Inj (Base)	0.0	0.0			
May-2007	End Year 1	86.3	80.8	941.5	31,604.1	29,569.5
May-2008	End Year 2	78.3	63.7	0.0	60,268.6	52,883.4
May-2009	End Year 3	73.8	52.2	0.0	87,261.9	71,983.7
May-2010	End Year 4	67.5	49.8	0.0	111,980.0	90,213.4
May-2011	End Year 5	44.9	34.3	0.0	128,407.3	102,752.7

Table 2.3.3 Energy Balance

	Year	Operating Energy Balance <GJ/day>		Cumulative Energy Balance <GJ>		
Year		Daily Gas Produced <GJ/d>	Daily Fuel Consumption <GJ/d>	Cumulative Steam Injection (GJ)	Cum Gas Production <GJ>	Cum Fuel Gas Consumed <GJ>
	Pre-Inj (Base)	0.0	0.0		0.0	0.0
May-2007	End Year 1	1,749	121	2,270	1,069,291	79,892
May-2008	End Year 2	2,107	223	0	1,842,267	161,169
May-2009	End Year 3	1,555	122	0	2,407,801	243,519
May-2010	End Year 4	1,367	123	0	2,906,938	324,433
May-2011	End Year 5	1,113	123	0	3,313,195	369,317

Table 2.3.4 Net Cumulative Energy and Material Balance

Year	Year	Net Balances: Net Cumulative Gas Injected <e3m3>	Net Balances: Net Cumulative Energy Produced <GJ>
	Pre-Inj (Base)		
May-2007	End Year 1	2,034.6	987,128.6
May-2008	End Year 2	7,385.2	1,681,097.6
May-2009	End Year 3	15,278.2	2,164,281.9
May-2010	End Year 4	21,766.7	2,582,505.4
May-2011	End Year 5	25,654.6	2,943,878.2

2.4 Estimate of Reserves

The plot of the net gas production (Figure 2.4.1) continues to decline with time and appears to be extrapolating to a cumulative EnCAID formation gas recovery of approximately 3.5 to 3.7 BCF (at a minimum rate of 0.5 MMSCFD). As shown in Figure 2.4.2, the currently estimated recovery factor is approximately 87%. This expected EnCAID formation gas recovery is slightly lower than the pretest expectation of 4 BCF but is still within a reasonable tolerance range.

Figure 2.4.1 Net Gas Balance

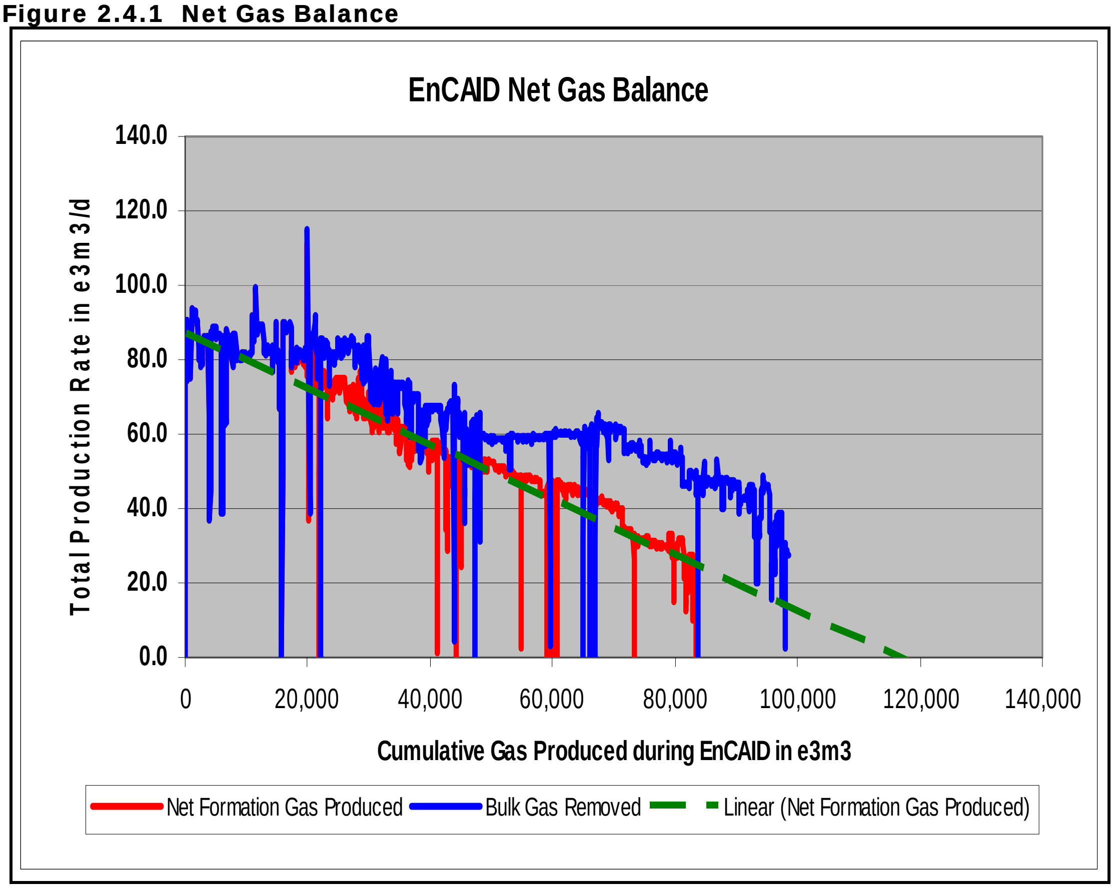
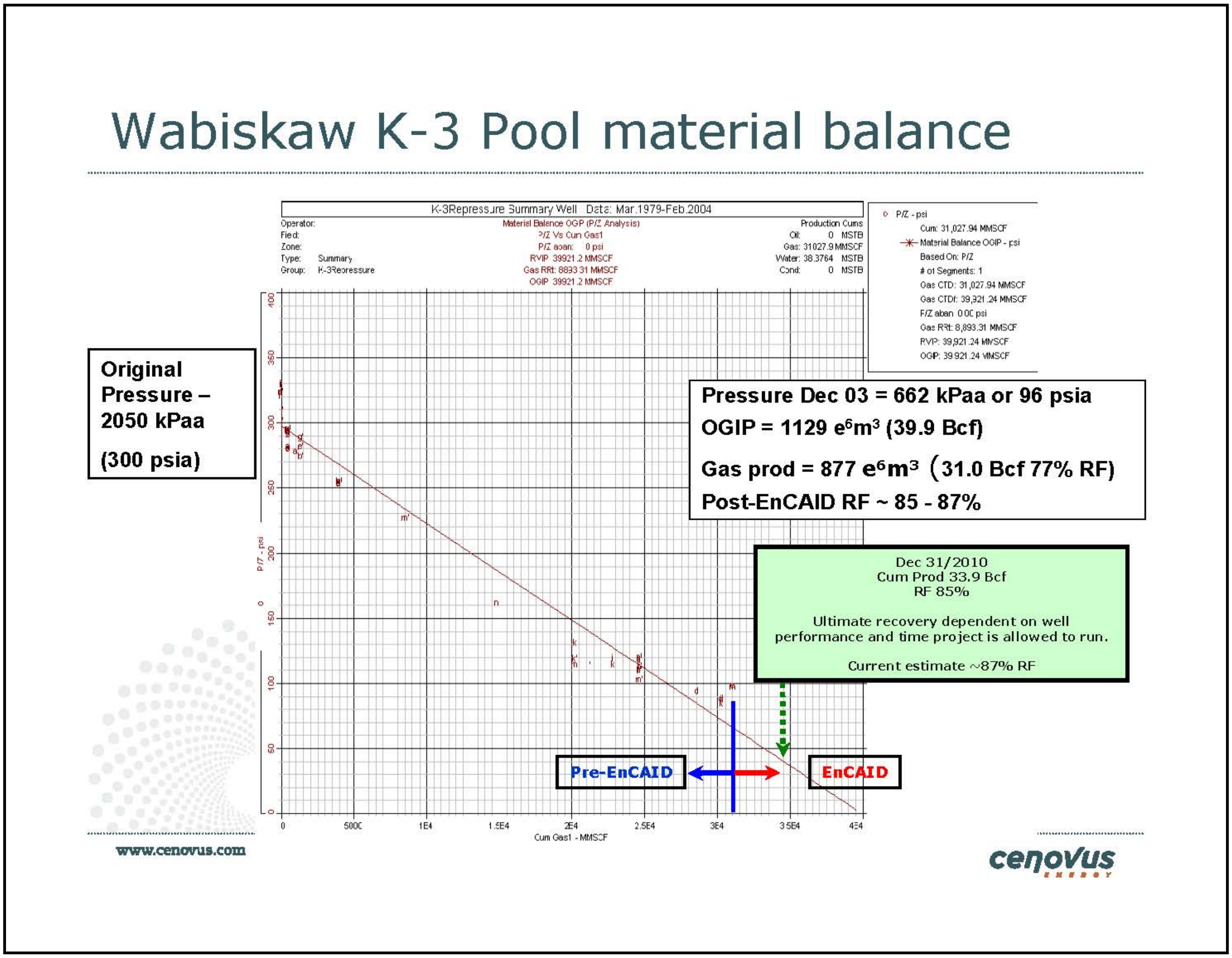


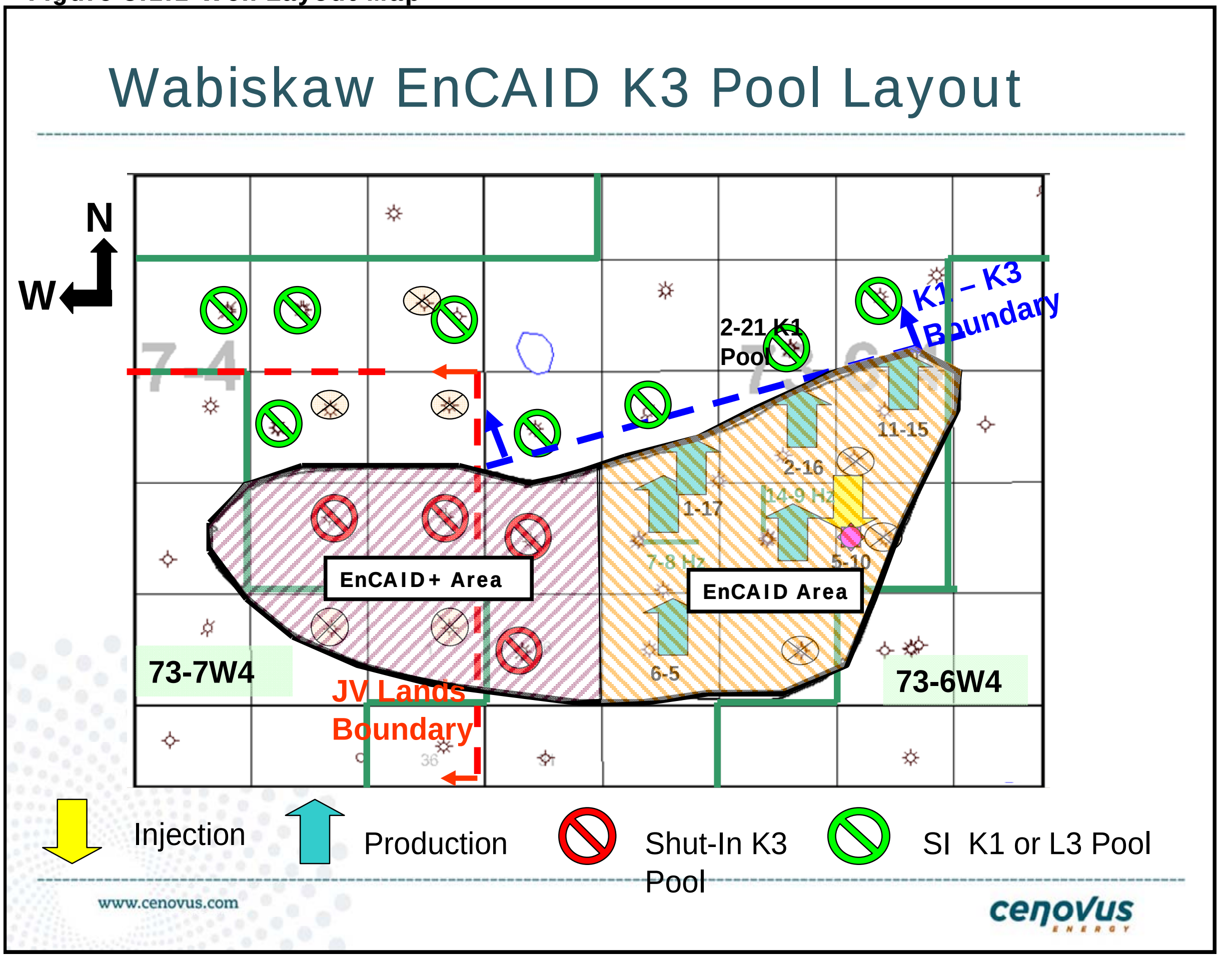
Figure 2.4.2 Pool Material Balance



3. Well Information

3.1 Well Layout Map

Figure 3.1.1 Well Layout Map



3.2 Drilling, Completion and Work-Over Operations

100/5-10-73-6W4 Injection Well

For the 100/5-10 injection well, an injectivity test with nitrogen followed by KCl water followed by nitrogen was performed on March 3rd, 2006 to try to assist injection design. An unusual response was observed where nitrogen injection at about 14.4 e3m3/day resulted in a wellhead pressure buildup to 9,200 kPag before a small “breakdown” was observed with final nitrogen slug injection of 6,835 m3. When 5-10 was on sweet gas production, it had reached peak production rates of 13.6 e3m3/day at an initial reservoir pressure of 1,450 kPag so this resistance to injection was unexpected. Following the switchover to water injection at 65 to 100 m3/day, a similar buildup and breakdown was observed around a wellhead pressure of 6,535 kPag (11.0 MPa downhole with the water gradient). During the subsequent repeated step of nitrogen injection, an almost identical surface pressure level of 9,300 kPag was reached at a similar cumulative nitrogen slug size. Given these results, the G-51 Injection Well Application requested and received approval for a short term wellhead pressure limit of 9,200 kPag with a long term operating wellhead pressure limit of 6,000 kPag.

The 100/5-10 well was eventually converted to injection status by reperforating the entire Wabiskaw gas interval, cementing the sump up to the gas-bitumen interface and cementing in place a thermocouple string allowing temperature readings uphole, across the gas interval and across the first fifteen meters of the bitumen interval. Due to corrosion concerns with the potential contact of hot water or steam and oxygen, the Galaxy 2000# thermal wellhead was coated with Impreglon and a 2 7/8" (73 mm) TK-7 coated tubing string was installed. This initial installation utilized an expansion joint, on-off connector, and retrievable packer that were designed for thermal conditions. Unfortunately, the Halliburton downhole retrievable assembly supplied was the "most thermal" available in the small 4 ½" casing sizes.

Shortly after the initiation of steam injection on April 23rd, 2006, this thermal installation failed at about 280 deg C resulting in a catastrophic destruction of the Petrospec thermocouple string and loss of annular isolation.

The redesign for the existing injector downhole configuration involved installation of a permanent thermal packer & expansion joint with AFLAS (Asbesto based) seal elements and without an on-off connector.

Shortly after startup, the thermocouple string was only reading the temperature of the injection air (see Figure 5.1.14) and in early 2011 Cenovus applied for and received approval to permanently remove it in order to do a more effective cleanout and stimulation of the air injection interval.

102/5-10-73-6W4 Observation Well

The 102/5-10 observation well was drilled in the first half of 2006, 30 meters west of the 100/5-10-73-6W4 injection well. The 102/5-10 well was cored and a total of 35.6 meters of core was recovered from 2 meters of shale, 5 meters of gas, 28 meters of bitumen and 2 meters of bottom shale. The well was subsequently completed as an observation well.

Prior to the completion of the 102/5-10 observation well, discussions with the Foster Creek Thermal group took place including a design study by Noetic Engineering to address the potential thermal stresses of a fire front passing through the observation location. In the final analysis, the safest wellbore design to remove the chance of casing collapse due to thermal stresses was to cement the monitoring string casing in place without an open annular space. The 102/5-10 well contains a Petrospec piezometer & thermocouple sensing string strapped onto the outside of 2 7/8" tubing (acting as casing) with a cement plug down about 300 meters from surface providing 140+ meters of cement over the combustion zone. An excellent cement job was performed with cement returns coming back up the 7" wellbore prior to the cement wiper plug being dropped and pushed to a level at 300 mKB. The core acquired from this well provided confirmation of the correct setting depths for three piezometer pressure measurements (in Joli Fou shale, in gas zone & 3 meters below gas-bitumen interface) and ten temperature measurements (1 in Joli Fou shale, 1 above formation, 2 in gas zone and 6 at varying depths in the top 15 meters of the bitumen leg).

Both the gas zone piezometer and the uphole shale monitoring piezometer failed subsequent to the completion operation. The critical bitumen zone piezometer has been reading values around 1.3 MPag.

The thermocouple string on the 102/5-10-73-6W4 has operated well and been a valuable resource for production monitoring and successful combustion confirmation.

100/6-10-73-6W4 Production & Observation Well

For the 100/6-10 production & observation well, a conversion took place from a single Colony A producer to the dual Wabiskaw Gas & Wabiskaw Bitumen completion. The only major difficulties on this well was the requirement to squeeze off the non-productive Colony zone and then perforate the Wabiskaw Gas zone twice to try to get a strong enough Wabiskaw pressure measurement.

Even after the second perforating run, the well bled down quickly in the gas interval from an initial surface pressure of about 265 kPag to zero. The well is unable to flow gas against a line pressure of about 110 kPag proving that the location is on the very edge of the Wabiskaw K-3 Pool and almost out of the zone with minimal gas crossover on logs. On the December 2006 bottomhole pressure surveys, the acoustic well sounder (AWS) value of 890 kPaa was obtained which is believable with the overall pool pressure so the well may actually be contacting the main pool through a low perm streak.

Due to its tight nature, the 6-10 well is not providing any gas production or any good gas compositional change information however it is supplying a continuous piezometer pressure reading from the bottom of the bitumen string from the perforations about 8 meters into the bitumen leg.

Segregation Problem at 2-16-73-6W4

Gas analysis and a segregation test in August 2007 suggested that there was wellbore communication between the Wabiskaw and Colony zones on the 2-16-73-6W4 dual completion. After consultation with the ERCB, flow was continued on the higher pressure Wabiskaw test zone while shutting in the Colony interval.

Subsequent work in the winter of 2008 showed the zonal segregation to be intact. Wellbore segregation between the Colony and Wabiskaw zones was confirmed with multiple successful segregation tests and zonal gradients that show a 200 kPag differential between the zones. The only explanation that Cenovus was able to find for the presence of nitrogen in the Colony zone was a failure in the surface check valves during the flow of both zones over the first two years of the flood. During flowline pressure fluctuations, the Colony zone would have been loaded up with nitrogen rich gas backflowing from the Wabiskaw zone through the faulty check valve over an extended period of time

Cenovus executed a flow test of the Colony zone in the 2-16-73-6W4 wellbore in the last half of 2009 to try to clean-up the cross flowed nitrogen from the Wabiskaw zone. After 6 months of flow at a controlled rate of 2 e3m3/d, the Colony zone still had not removed much of the nitrogen build-up so Cenovus returned to the original goal of EnCAID and restarted flow from the Wabiskaw zone (with the Colony zone blinded off).

Segregation Repair at 6-18-73-6W4

Following review of the December 2008 static gradient data, Cenovus became aware that the non-productive Wabiskaw and Colony well at 6-18-73-6W4 was continuously losing pressure. The downhole pressure trend at 6-18 was the only location where Wabiskaw zone pressure appeared to be abnormally decreasing. Cenovus reacted by shutting in all EnCAID gas production on January 19, 2009 as per Clause 16 of the original Approval 10440. (Since the air injection was able to only be reduced somewhat, but needed to be maintained to keep the combustion going, Cenovus self-disclosed the requirement to temporarily exceed the monthly voidage limit of 1.4 by going up to 1.675 in January 2009 and 10.339 in February 2009 due to this gas production shut-in.) As of February 26, 2009, the repair was completed on the 6-18 wellbore with segregation returned to the well as observed by the expected bottomhole pressure of 940 kPaa rather than the pre-repair pressures below 700 kPaa. In March 2009, the monthly voidage replacement ratio was returned to normal levels around 1.2 with the EnCAID gas production back on-line.

100/5-10-73-6W4 Stimulation to Recover Injectivity

Following review of the injectivity index trends (Figure 5.1.16) Cenovus investigated the rapid decrease in injectivity in October 2009 that lead to the lowest air injection rate of 19.4 e3m3/day (0.69MMSCFD) at a wellhead pressure of 3328 kPag. It is believed that a carryover of oil from the reciprocating compressors caused a downhole resistance near the 100/5-10-73-6W4 air injection well. To address this problem, Cenovus executed a solvent / surfactant / dispersant treatment on January 21, 2010 on the injection well and was able to recover injectivity back to the original injectivity index trend (0.008 $m3/day/kPa^2$). Since starting air injection in June 2006, the injectivity index has shown a straight line decline from initial values of 0.011 to 0.017 to the current levels of 0.008 however concern was raised when the sudden drop to 0.0017 $m3/day/kPa^2$ occurred. The steady decline in injectivity index trend is believed to be related to both a slow increase in formation pressure and a small degree of oil banking in the gas zone. The improvement in injectivity proved to be short lived and by Fall 2010, injectivity was again a significant concern. Pressure fall-off testing in December 2010 showed the presence of significant near wellbore damage (Figures 5.1.17 & 5.1.18). A more aggressive stimulation was planned in early 2011 with a backup plan of converting another wellbore to air injection use if that was unsuccessful.

3.3 Well Operation

Operating the project wells consisted of balancing the air injection rates with natural gas production to maintain the approved Voidage Replacement Ratios and maintain or slightly increase the formation pressure. The production wells were produced to fairly high nitrogen contents, although towards the end of the reporting period some of the wells had to be shut in earlier in order to maintain sales quality gas as the EnCAID gas diluted with other production at Cenovus's Primrose North Gas Plant

3.4 Well List and Status

The EnCAID project Wabiskaw K-3 Pool wells are shown in Table 3.4.1.

Table 3.4.1 Well List

Well Name	Zone	Pool	Status
00/05-10-073-06W4/0	Wabiskaw	K-3	Air Injection Well
02/05-10-073-06W4/0	Wabiskaw	K-3	Observation Well
00/06-10-073-06W4/2	Wabiskaw	K-3	Observation Well
00/14-09-073-06W4/0	Wabiskaw	K-3	Production Well, Shut In June, 2007
00/01-17-073-06W4/0	Wabiskaw	K-3	Production Well, Shut In Oct 2010
00/02-16-073-06W4/0	Wabiskaw	K-3	Production Well, Shut In Dec 2010
00/11-15-073-06W4/0	Wabiskaw	K-3	Production Well, Shut In Dec 2010
00/06-05-073-06W4/0	Wabiskaw	K-3	Production Well, Flowing
00/07-08-073-06W4/0	Wabiskaw	K-3	Production Well, Flowing
00/06-06-073-06W4/2	Wabiskaw	K-3	Shut In, pending EnCAID +
00/06-07-073-06W4/2	Wabiskaw	K-3	Shut In, pending EnCAID +
00/10-11-073-07W4/0	Wabiskaw	K-3	Shut In, pending EnCAID +
00/10-12-073-07W4/0	Wabiskaw	K-3	Shut In, pending EnCAID +

3.5 Wellbore Schematics

The figures below show the wellbore schematics for the key EnCAID project wells:

Figure 3.5.1 Wellbore Schematic for 100/5-10-73-6W4 Injector

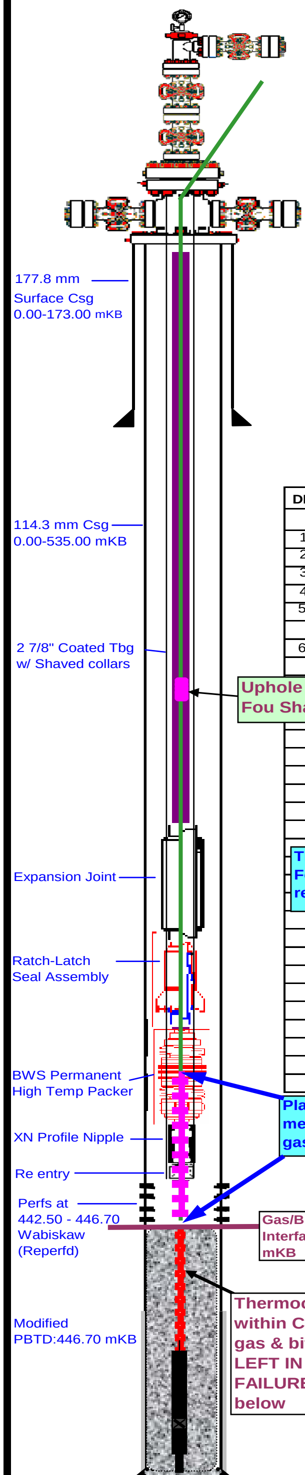
FINAL Post Steam Failure Downhole Well Profile

Date : May 27 2006

Well Name / location: **AEC KIRBY**

UWI: 100/05-10-073-06W4 **Licence #** 0198100

RTU #



KB ELEV:	689.9 m	**KB to CF:**	m
GL ELEV:	686.7 m	**KB to THF:**	m
TD:	536.00 mKB	**PBTD:**	447.00 mKB

TUBULARS	**SIZE** (mm)	**WEIGHT** (kg/m)	**COUPLING**	**GRADE**	**THREAD**	**DEPTH** (mKB)
SURFACE:	177.8	25.3		H-40		173.00
INTERMEDIATE:						
PRODUCTION:	114.3	14.1		J-55		535.00
LINER:						
Coiled Tbg.	2 7/8 "	With Shaved Collars & Coated				**442**

ZONE/PERFS:
Wabiskaw 442.5 TO 445.00 mKB
Reperf March 2006 442.7 TO 446.70 mKB 16 gm DP charges 13SPM 60 deg.

	DESCRIPTION (starting at the bottom)	**LENGTH** (m)	**DEPTH** str 1(mKB)	**DEPTH** str 2(mKB)
	BOTTOM OF TOOL STRING			
1	60.3 mm Re entry Guide			
2	47.63 mm X Profile Nipple			
3	Halliburton Wireline Set 114.3 mm 64.77 mm BWS Permanent Packer with AFLAS High Temp Elements		434.2 mKB	
4	Halliburton Ratch-Latch Seal Assembly with ATR High Temp Seals			
5	Expansion Joint .. 3 meter x 60.3 mm with 3 meter stroke fully open for 7.22 meter overall length			
6	2 7/8" (73 mm) Tbg with shaved collars ... L-80 with Premium Connections and internally coated TK	442.00		
	KB . 3.2 m	3.20		
	TALLY	445.20		
	KB TO CASING BOWL FLANGE DISTANCE "H"			
	TUBING BOTTOM	**445.20**		

Thermocouple Failure on 8 of 10 thermocouple points about 7 to 10 hours after steaming with only Joli Fou Thermocouple & 2 meters below G/B point working (on same cable/wire) .. Look to remove string, replace segregation & run a new "suspended" rather than cemented in thermocouple string

Primary Cement with 7 tonnes of ThixoTHERM LT blend with 1 m3 returns

TALLY	
KB TO CASING BOWL FLANGE DISTANCE "H"	
TUBING BOTTOM	

Plan for new Thermocouple string to cover 4 temps across gas zone (every meter), 2 meters above gas, 5 meters above gas, 10 meters above gas & Joli Fou shale at ~300 mKB .. End point at cement top on base of gas about 446.7 mKB

WORKING PRESS.: MPa BPV THREAD(Y/N):
SOUR TRIM ? FLOW TEE TOP CONN.: mm

WELLHEAD DATA

	Make (or Model)	SIZE (mm)	Wk. Press. (MPa)	SERIAL NUMBER
MASTER VALVE :		114.3	14	Dual Flanged Master Valve
WING VALVE:				
ING VALVES :				

D DESCRIPTION

Select Single Wellhead to be changed to double master valve flanged wellhead

CE CSG. VENT: BURST PLATE RATING: kpa
OPEN/CLOSED 0PEN

REMARKS:

After initial steam failure of string, lower section of cemented in thermocouple string was lost
Rebuilt thermocouple string has 10 thermocouple points concentrated across & just above gas zone
..Thermocouples will be type K to allow operation up to 1200 Deg C

Figure 3.5.2 Wellbore Schematic for 102/5-10-73-6W4 Observation Well

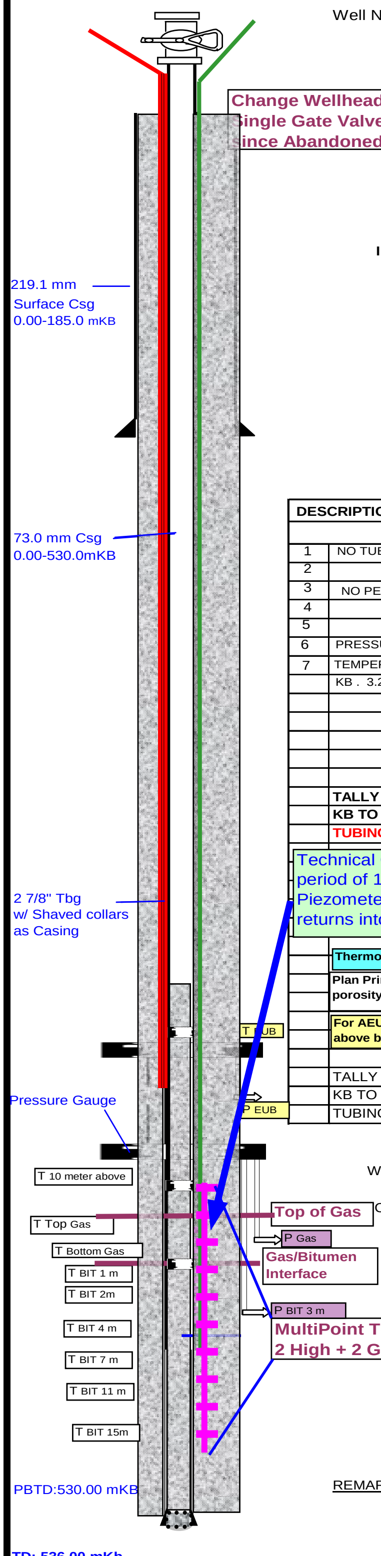
Downhole Well Profile - Cement & Abandon Concept

Date : November 21st, 2005

Well Name / location: **EnCana KIRBY OBS**

UWI: 102/05-10-073-06W4 **Licence #**

RTU #



ELEV:	689.9	m	**KB to CF:**		m
ELEV:	686.7	m	**KB to THF:**		m
TD:	536.00	mKB	**PBTD:**	446.00	mKB

TUBULARS	SIZE (mm)	WEIGHT (kg/m)	COUPLING	GRADE	THREAD	DEPTH (mKB)
SURFACE:	219.1	35.7		J-55		185.0
INTERMEDIATE:						
PRODUCTION:	73.0	9.67		J-55		530.0
LINER:						
Coiled Tbg.						

ZONE/PERFS: Wabiskaw 442.0 TO 476 mKb… NO PERFS just Obs Equipment

	DESCRIPTION (starting at the bottom)	**LENGTH** (m)	**DEPTH** str 1(mKB)	**DEPTH** str 2(mKB)
	BOTTOM OF TOOL STRING			
1	NO TUBING PLANNED BUT INSERT THERMOCOUPLE IN CENTRE OF WELL			
2				
3	NO PERFORATIONS PLANNED AT LEAST UNTIL FRONT PASSES			
4				
5				
6	PRESSURE ASSEMBLY FOR TWO MEASUREMENTS POINTS INSERTED IN CASING RUN	445 & 451 m KB		
7	TEMPERATURE ACQUISITION THROUGH MULTIPOINT THERMOCOUPLE STRING	445 to 454 m KB (4 Points)		
	KB . 3.2 m	3.20		
	TALLY			
	KB TO CASING BOWL FLANGE DISTANCE "H"			
	TUBING BOTTOM			

Technical Challenge was design of Casing to allow up to 800 - 1000 Deg C peak temperatures for a period of 1 week across the "Gas Interval" … BEST design appeared to be to strap the thermocouple & Piezometers onto the OUTSIDE of 2 7/8" Tubing as CASING and thermally cement with very good returns into place … Cement top inside tubing left around 300 meters down for reentry IF required

Thermocouple string to be run ON OUTSIDE of tubing to be CEMENTED in Place

Plan Primary Cement with 7 tonnes of ThixoTHERM LT blend with premium control on porosity, particle size, placement & curing

For AEUB Containment Concerns, run thermocouple point & pressure sensor into casing above bitumen zone in shale streak

TALLY

KB TO CASING BOWL FLANGE DISTANCE "H"

TUBING BOTTOM

STRING WT:		daN	WT. ON PACKER		daN
WT. ON HANGER:		daN	FLANGED/THREADED:		
TBG SPOOL :			LIFT THREAD:		mm
WORKING PRESS:		MPa	BPV THREAD(Y/N):		
SOUR TRIM ?			FLOW TEE TOP CONN.:		mm

WELLHEAD DATA	Make (or Model)	SIZE (mm)	Wk. Press. (MPa)	SERIAL NUMBER
MASTER VALVE :		114.3	14	Single Flanged Master
WING VALVE:				
VALVES :				

WELLHEAD DESCRIPTION

Minimal Wellhead needs due to "almost abandoned" well state with sensing lines coming up cement annulus

SURFACE CSG. VENT:

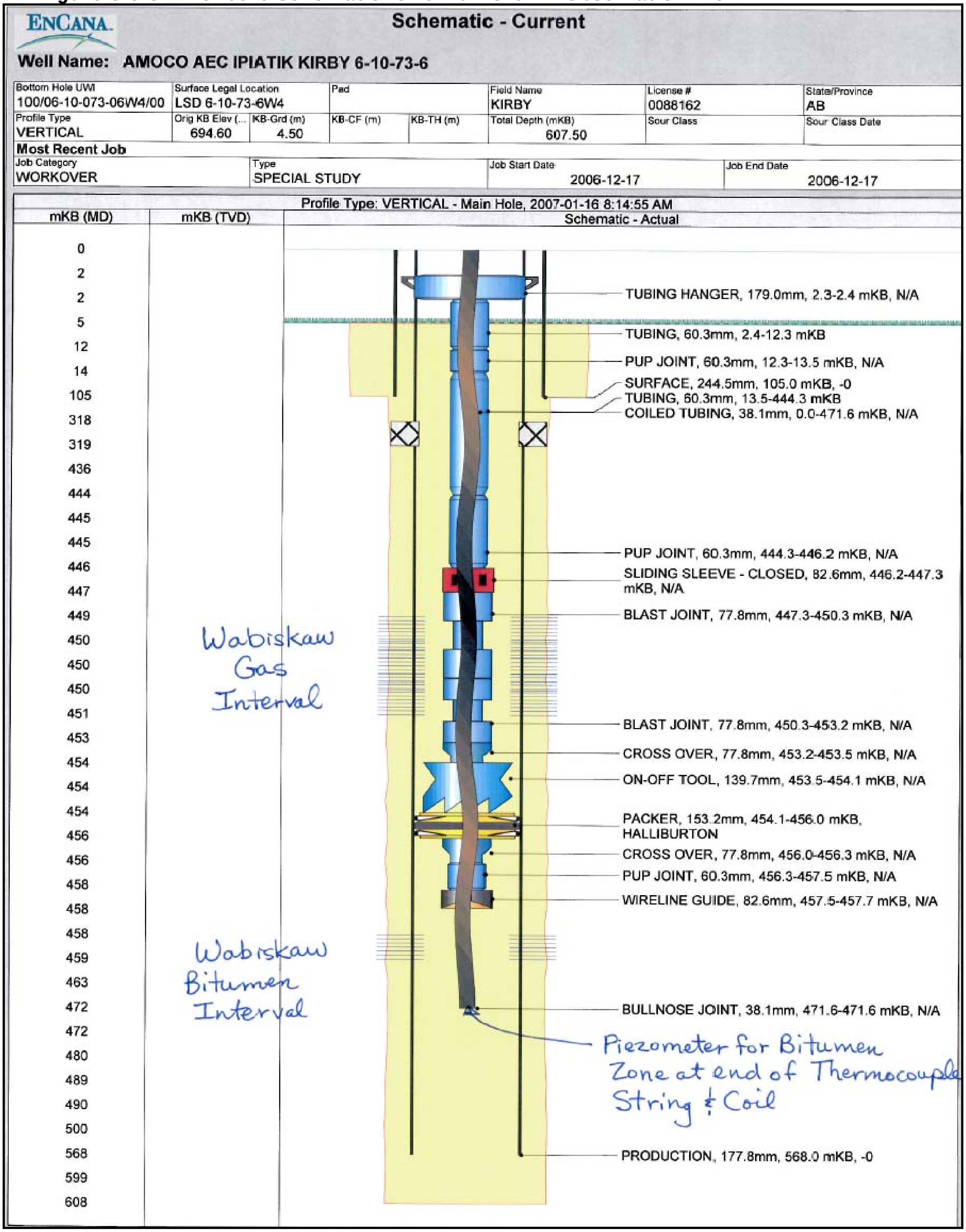
OPEN/CLOSED: 0PEN

BURST PLATE RATING: kpa

REMARKS:

Thermocouples will be type K to allow operation up to 1200 Deg C

Figure 3.5.3: Wellbore Schematic for 6-10-73-6W4 Observation Well



3.6 Spacing and Pattern

Since the project was implemented in an existing shut-in pool the well spacing and pattern was pre-determined. Due to the very low viscosity of the gas, similarity of the displacing medium (combustion products) and extremely high permeability of the reservoir, fingering and sweep efficiency are not overriding concerns like they are in enhanced oil recovery projects. The choice of which well to convert for air injection, and where to drill the observation well were the main considerations in planning the project. The 100/5-10 well was chosen as the injector because of its central location in the thickest and most permeable part of the gas reservoir as well as proximity to a source of fuel gas and to a high grade road.

4. Production Performance

4.1 Production and Injection History

The figures below show the production and injection history for the EnCAID project wells:

Figure 4.1.1 EnCAID Composite Production History

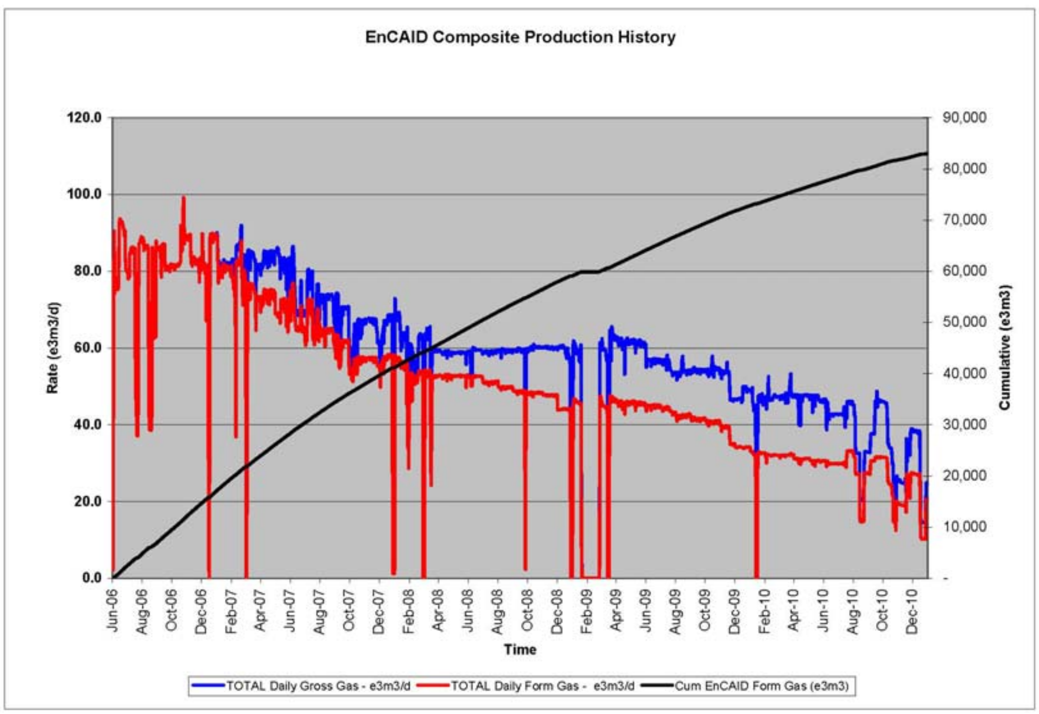


Figure 4.1.2 7-8-73-6W4 Production History

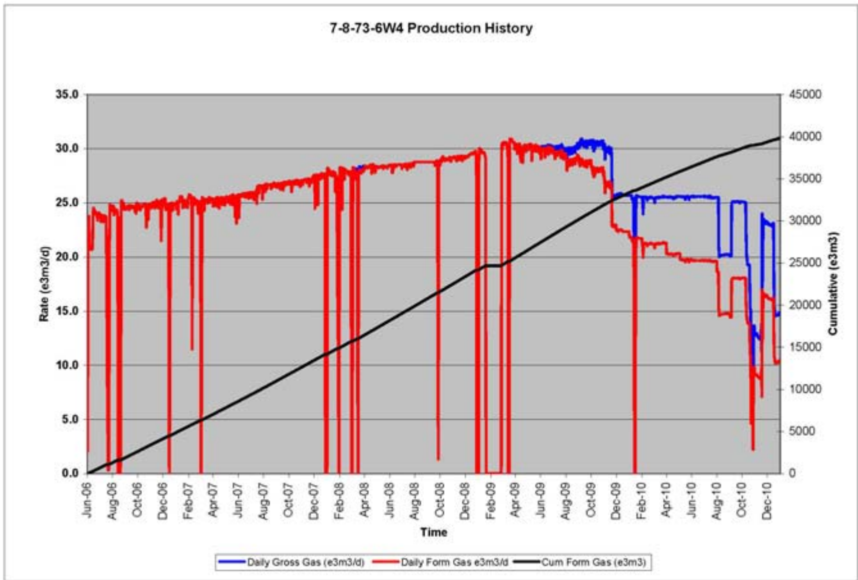


Figure 4.1.3 2-16-73-6W4 Production History

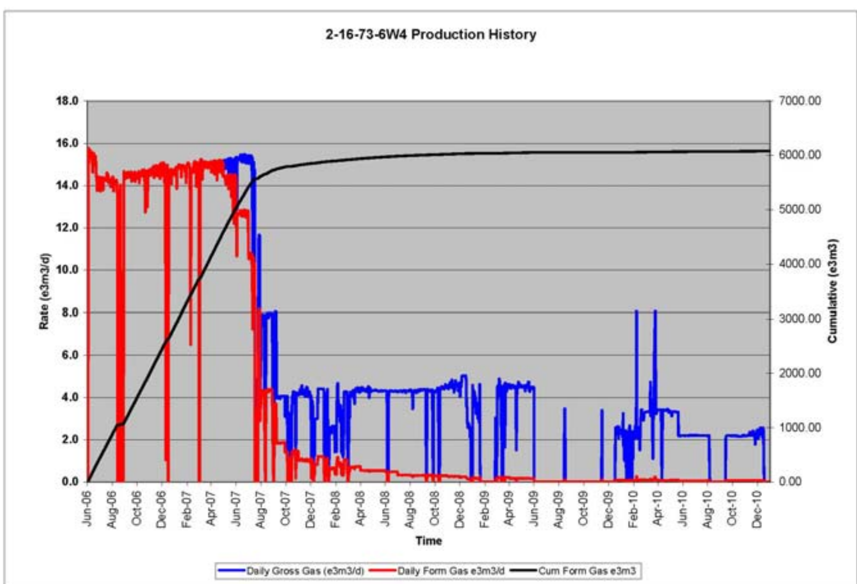


Figure 4.1.4 14-9-73-6W4 Production History

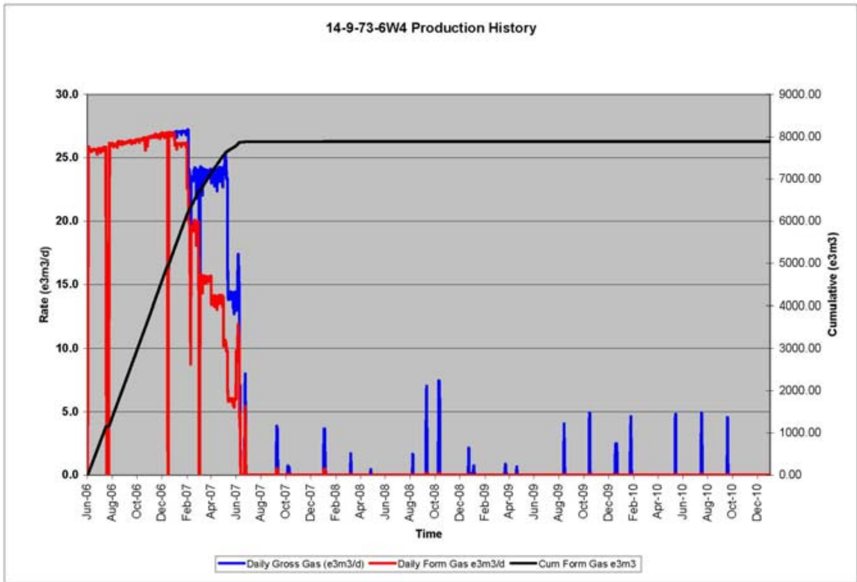


Figure 4.1.5 11-15-73-6W4 Production History

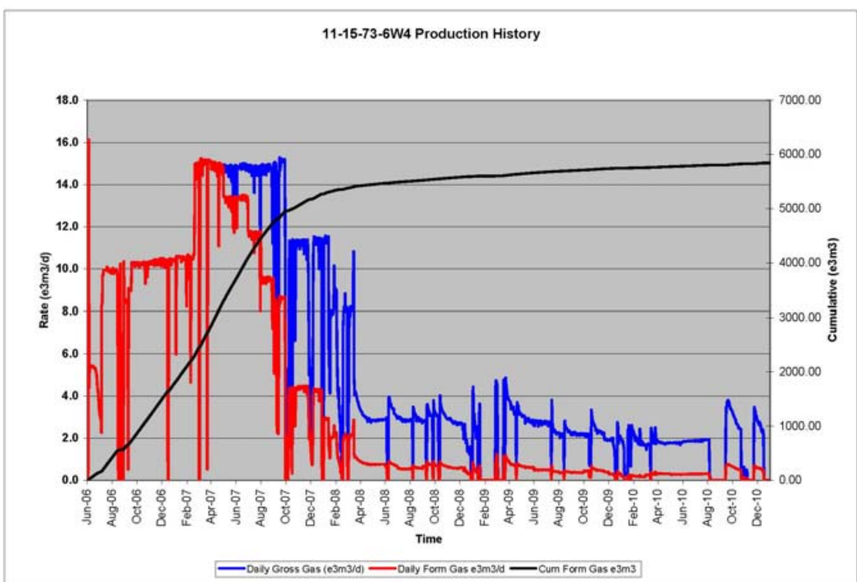


Figure 4.1.6 1-17-73-6W4 Production History

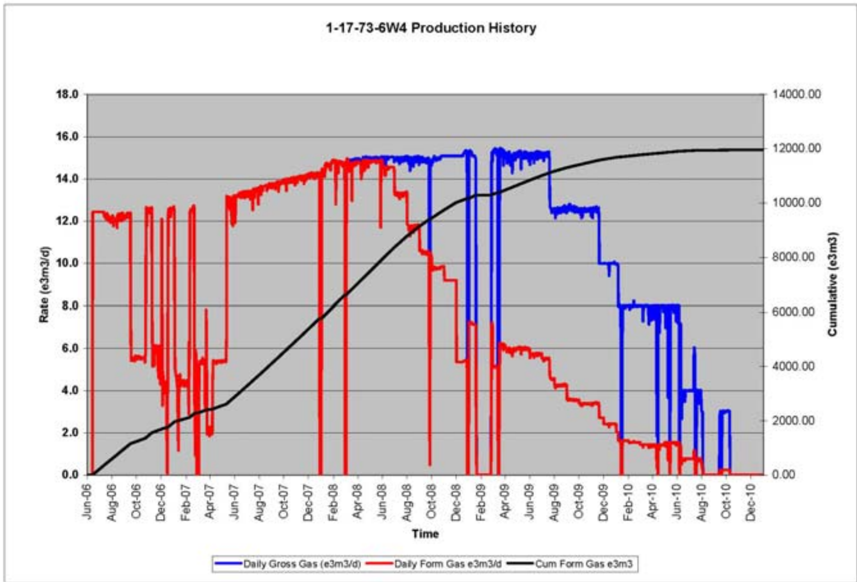


Figure 4.1.7 6-5-73-6W4 Production History

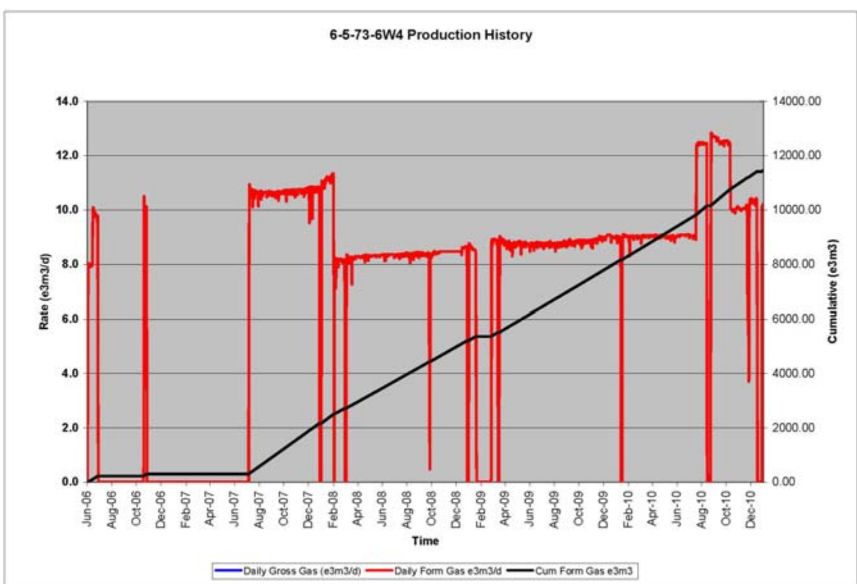
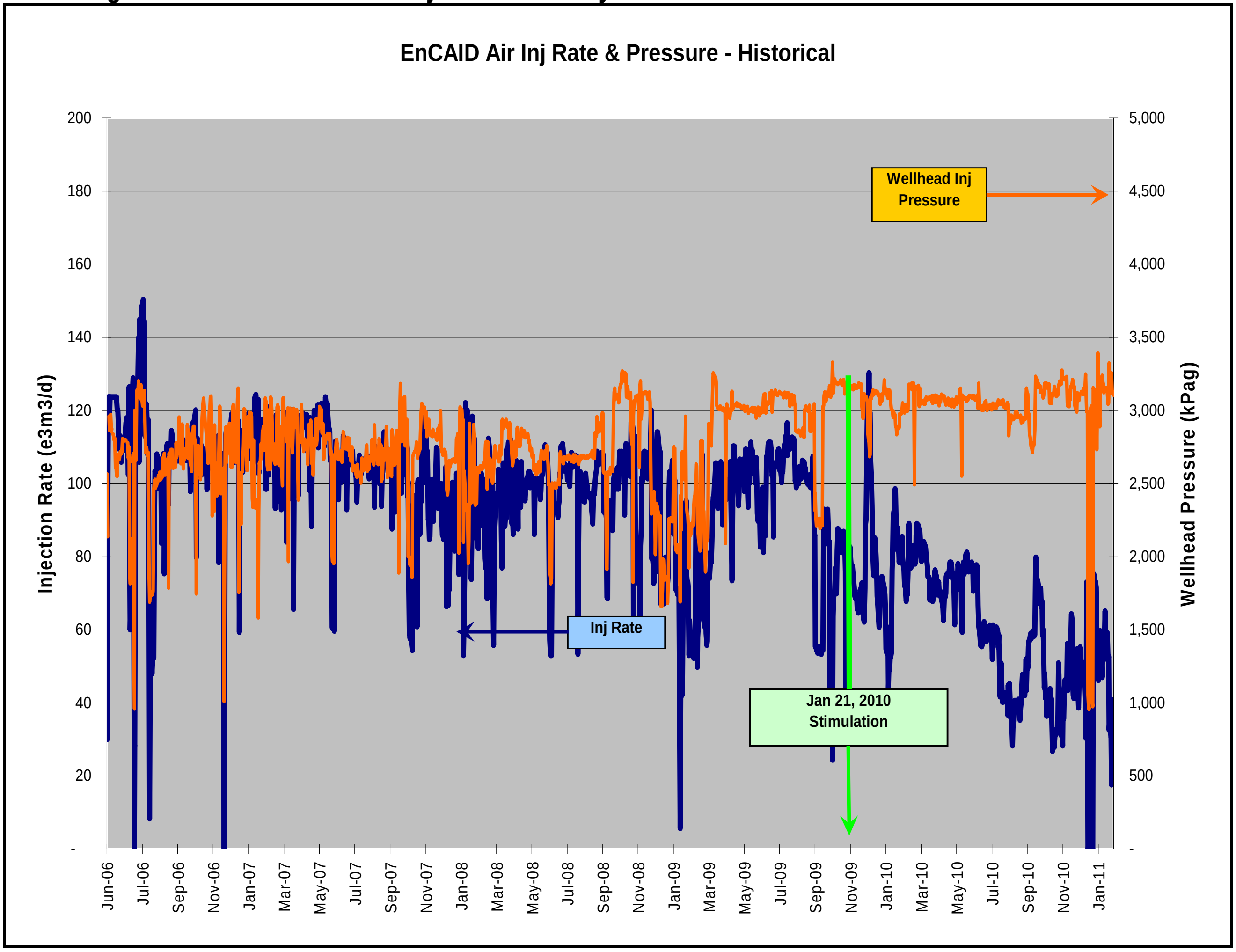


Figure 4.1.8 EnCAID Air Injection History



4.2 Composition of Produced / Injected Fluids

The design of the EnCAID project involves the use of a combination of produced gas analyses at commercial laboratories and on-line gas chromatographic readings at the Primrose North Gas Plant inlet. The figures below illustrate the observed changes in gas composition.

Figure 4.2.1 shows the historical nitrogen composition of five wells in relative response time. Figure 4.2.2 shows the nitrogen levels in the pool at the end of 2010. The first producer to show a nitrogen response was the 14-9-73-6W4 horizontal well in January 2007. By June 2007, the 14-9 hz well exceeded 65% nitrogen and was shut-in. Initial numerical simulation models indicated that the first nitrogen response at the closest production well (14-9 hz) was expected in 9 to 14 months so the observed rise in nitrogen in 7.5 months was slightly early. The nitrogen responses at 11-15, 2-16, 1-17 and 7-8 hz also appear to be early compared to the original simulation. The rate of rise in nitrogen levels would appear to suggest somewhat radial flow since the closest producer at 14-9 showed the steepest response with the next “ring” of producers 11-15 & 2-16 showing a slower but similar rise in nitrogen levels and the second row of producers only showing a slow nitrogen response at 1-17 & 7-8, while producer 6-5 continues to show the low concentration levels of nitrogen over its production.

Figure 4.2.1 Historical Nitrogen Composition Changes

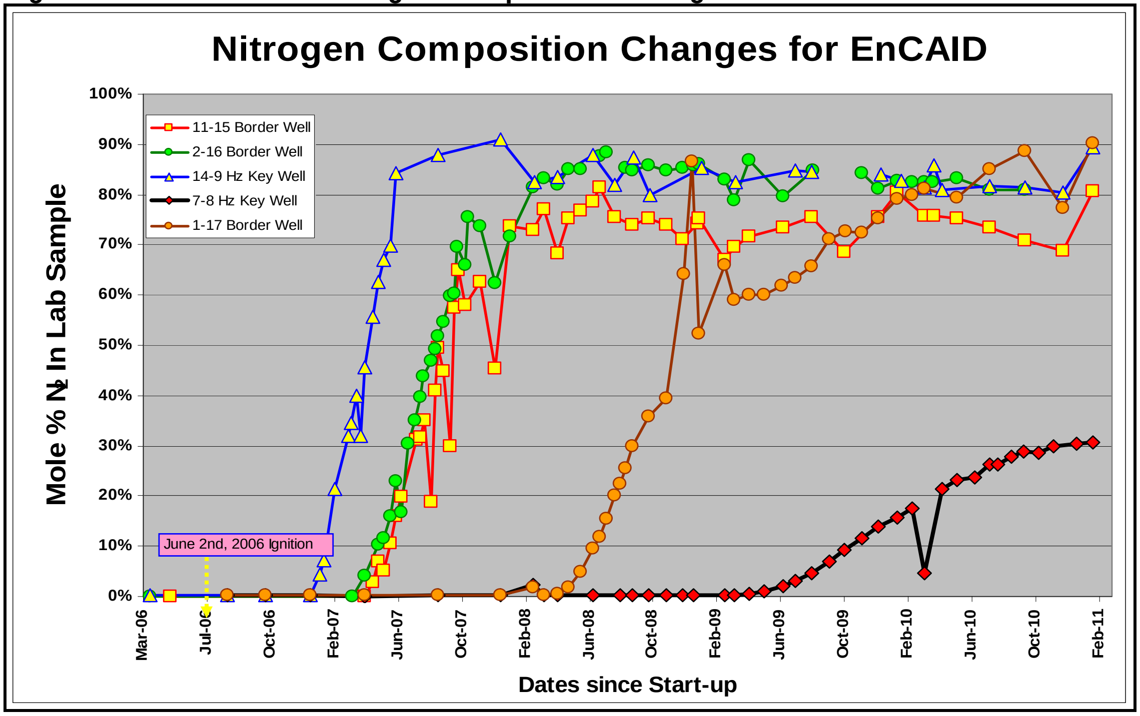


Figure 4.2.2 Map of Nitrogen Response

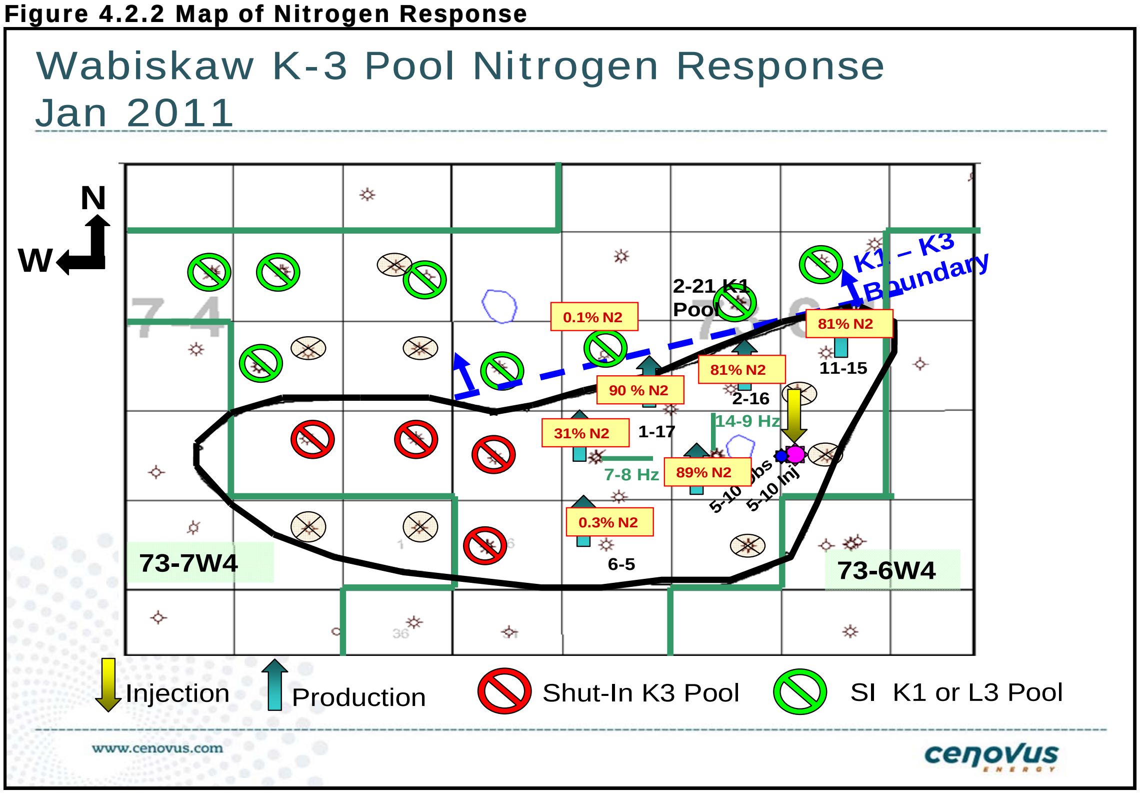


Figure 4.2.3 shows the changes in gas composition for 1-17-73-6W4 over time. Nitrogen levels of 79% were recorded in January 2010, peaking in January 2011 at 90%. Carbon dioxide levels rose from a January 2010 level of 0.1% to 4.6% in January 2011. The delayed carbon dioxide response could be explained by the greatly increasing reservoir volume as you radiate out from the 100/5-10-73-6W4 injector and therefore a larger area for carbon dioxide to go into solution before reaching a saturation point. Minor amounts of CO were observed infrequently with a peak in September 2010 of 0.26%. 1-17 was allowed to flow at average rate of 6.6 e^3m^3/d for the period January 2010 until July 2010 when nitrogen levels rose to 85%. The well was flowed at average rate of 2.7 e^3m^3/d for the period mid-September to mid-October when sufficient blending volumes were available. However, the well has not produced since mid-October 2010 due to lack of blend gas availability at the Primrose plant and the high nitrogen levels in this well.

Figure 4.2.3 Laboratory Gas Analysis for 1-17-73-6W4 Producer

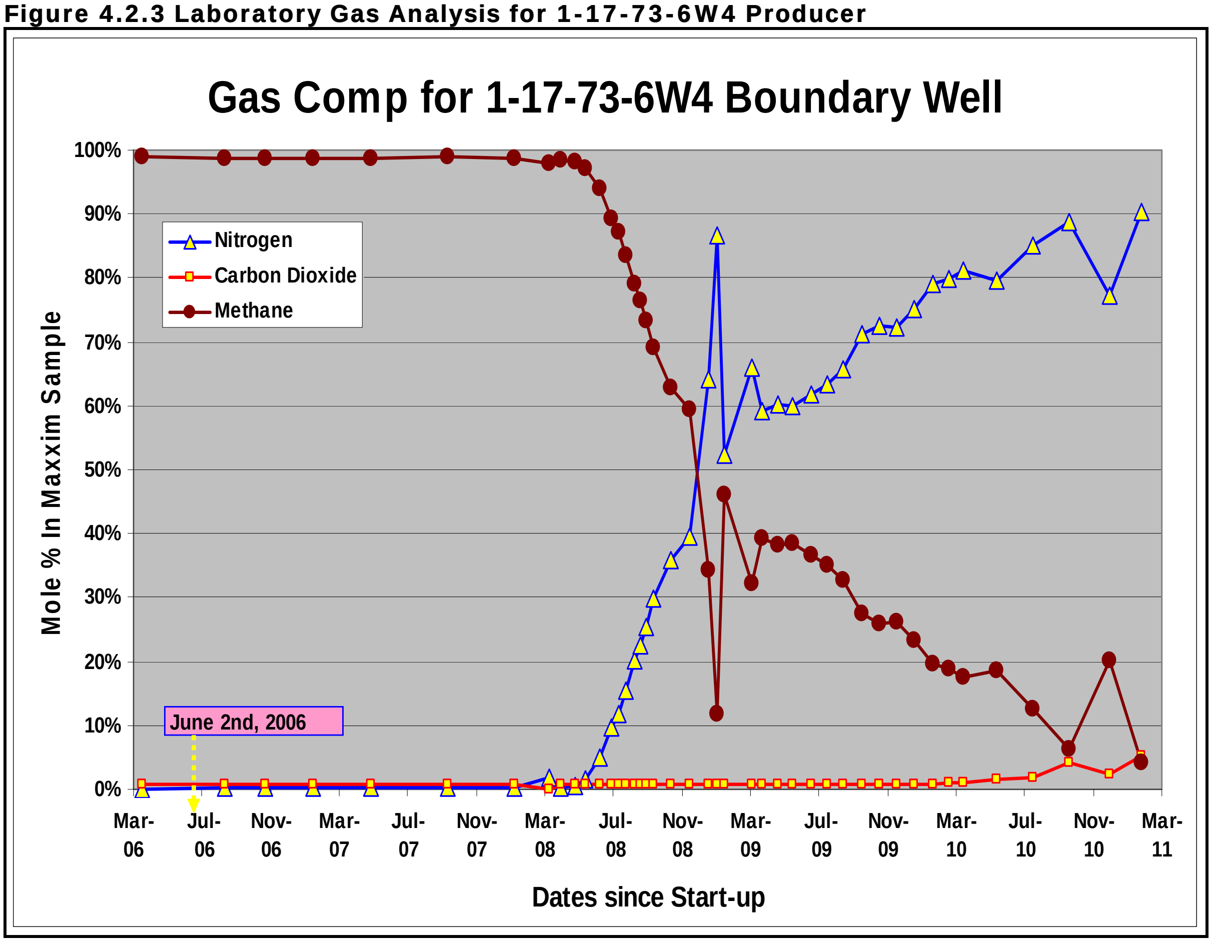


Figure 4.2.4 shows the changes in gas composition for 2-16-73-6W4 over time. The nitrogen response started in April 2007, rising to 70% by October 2007 followed by consistent nitrogen levels throughout 2010 ranging from 81% to 83%. Carbon dioxide levels began rising in late 2007 and have been constant at 15%. Minor amounts of CO were observed during the 2010 reporting period with January reporting 0.17% with a peak in September having 0.25% with January 2011 coming in at 0.13%. Due the high nitrogen level 2-16 flowed from January 2010 until mid-December at average rate of 2.3 e^3m^3/d. The well was shut-in mid December 2010 due to lack of blend gas availability at the Primrose plant.

Figure 4.2.4 Laboratory Gas Analysis for 2-16-73-6W4 Producer

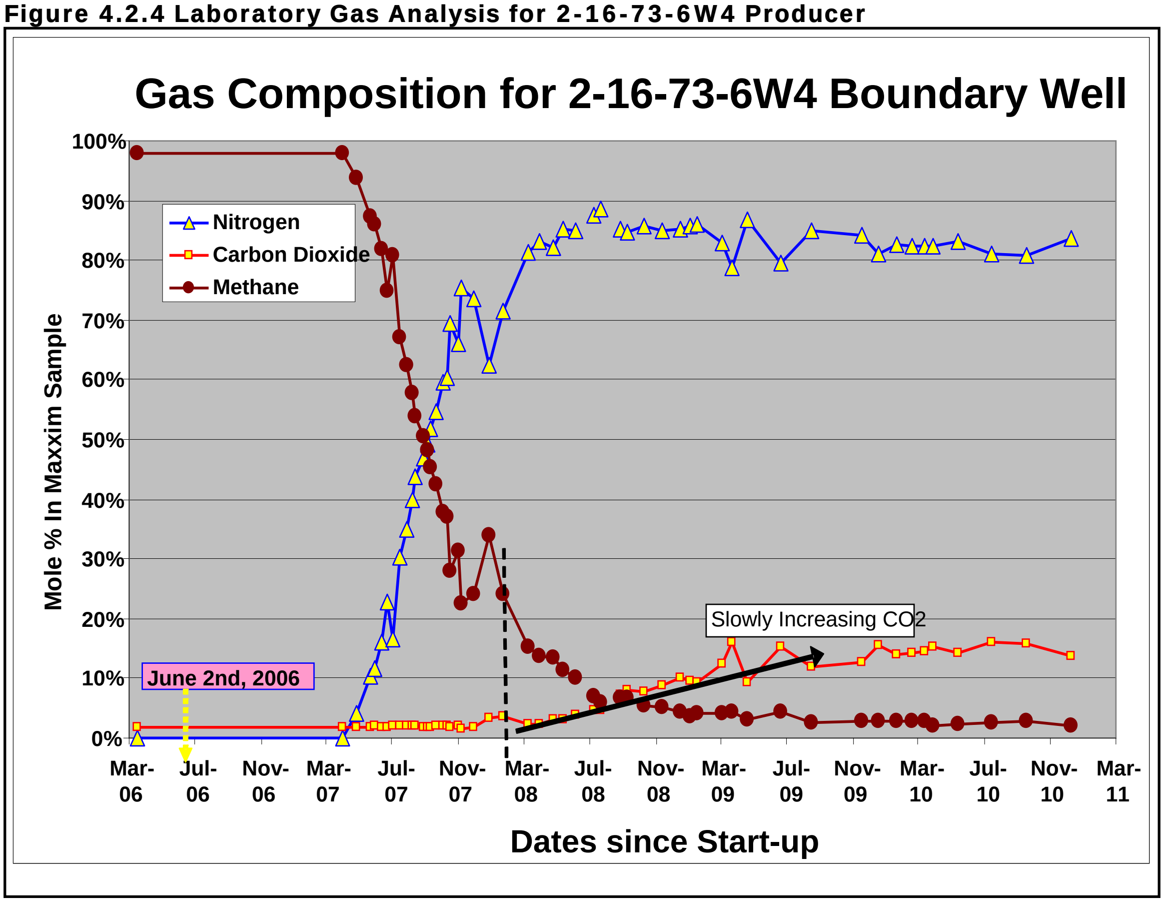


Figure 4.2.5 shows the gas composition for 6-5-73-6W4 over time. Nitrogen, carbon dioxide and CO levels have remained low throughout the reporting period. Due to the low nitrogen levels of this well, the production has not been curtailed.

Figure 4.2.5 Laboratory Gas Analysis for 6-5-73-6W4Producer

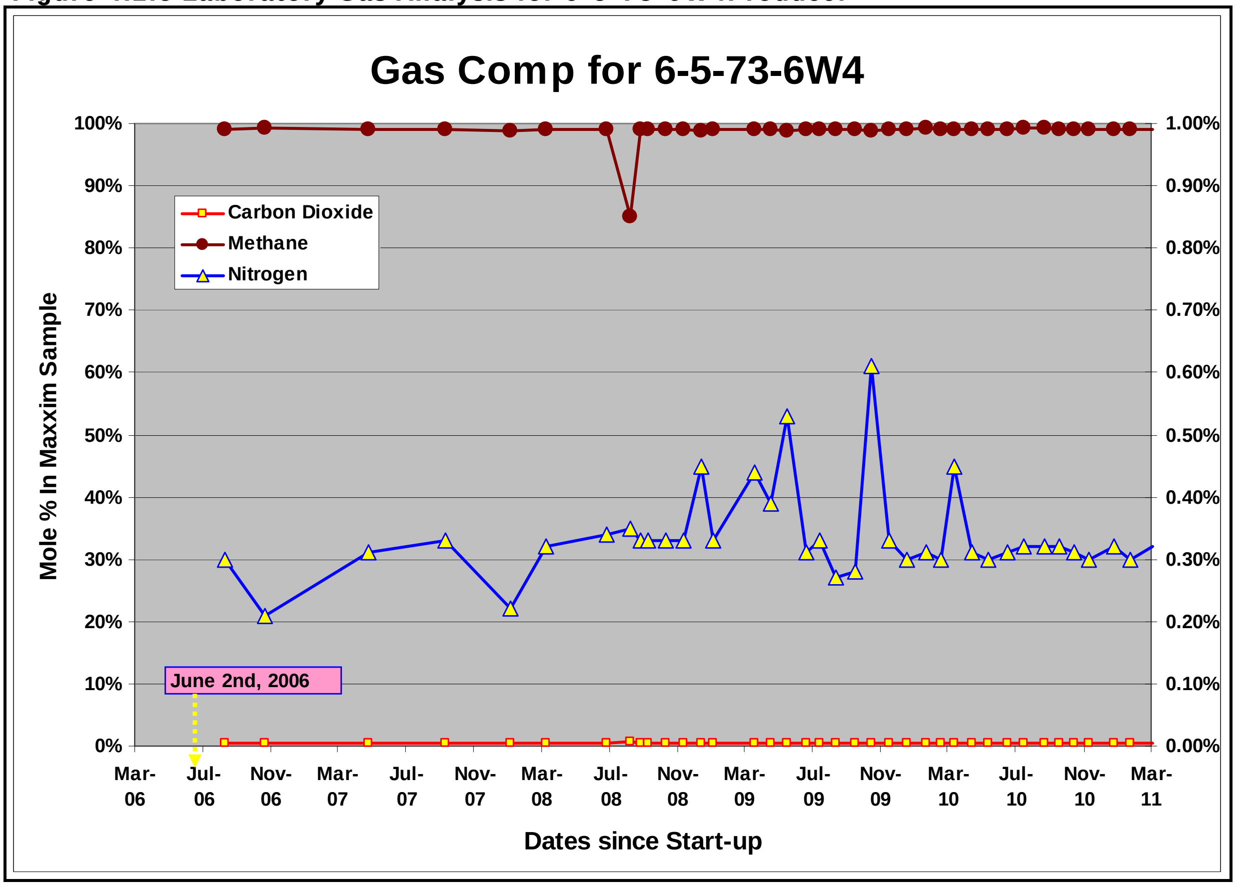


Figure 4.2.6 shows the changes in gas composition for 7-8-73-6W4 over time. Nitrogen levels of 16% were recorded in January 2010, rising to 31% in January 2011. Carbon dioxide levels have remained constant at 3%. Minor amounts of CO at 0.07% were reported during the first half of 2010, while in the second half of the reporting period no CO was recorded from the gas analysis. The 7-8 well flowed from January 2010 to September 2010 at an average rate of 24.8 e^3m^3/d, however starting in October 2010 the production rate was dropped to an average of 16.8 e^3m^3/d primarily due to the rise in nitrogen levels and the lack of blend gas availability at the Primrose plant.

Figure 4.2.6 Laboratory Gas Analysis for 7-8-73-6W4 Hz Producer

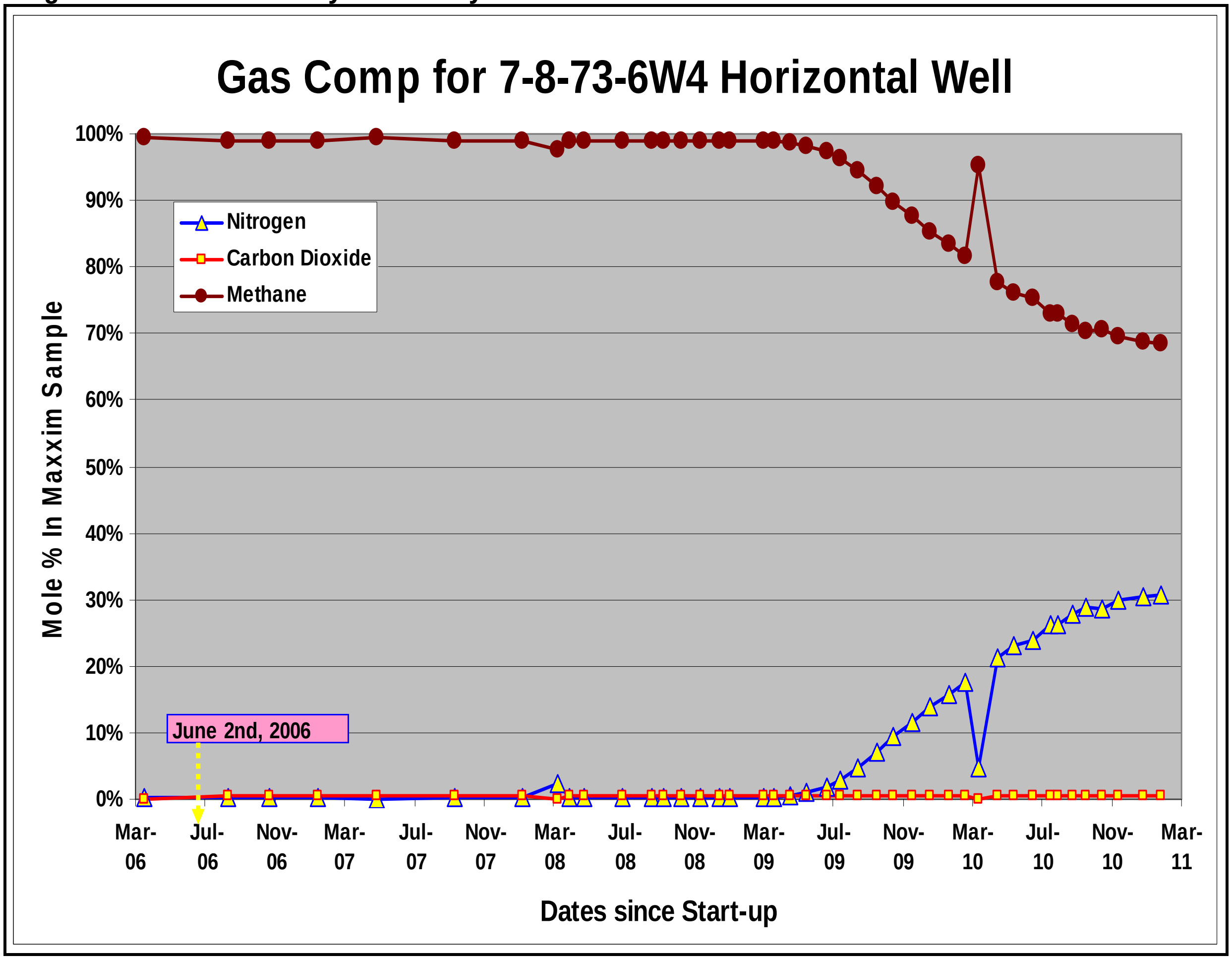


Figure 4.2.7 shows the changes in gas composition for 11-15-73-6W4 over time. Nitrogen response occurred at 11-15 starting in May 2007, rising to 60% by October 2007, reaching 81% by July 2008 and remaining in the 70% to 80% range. The carbon dioxide levels have only risen since July 2008 and are currently in the 10% range. Minor amounts of CO have been observed with January 2010 reporting 0.17% and January 2011 coming in at 0.13%. The 11-15 well was flowed intermittently between January 2010 until August 2010 at daily rates averaging 1.8 e^3m^3/d, then again from mid-September to mid-October at average rate of 3.1 e^3m^3/d. Then finally from late November until mid-December at average rate of 2.7 e^3m^3/d, however commencing mid-December it was shut-in due to the high nitrogen levels and the lack of blend gas availability at the Primrose plant.

Figure 4.2.7 Laboratory Gas Analysis for 11-15-73-6W4 Producer

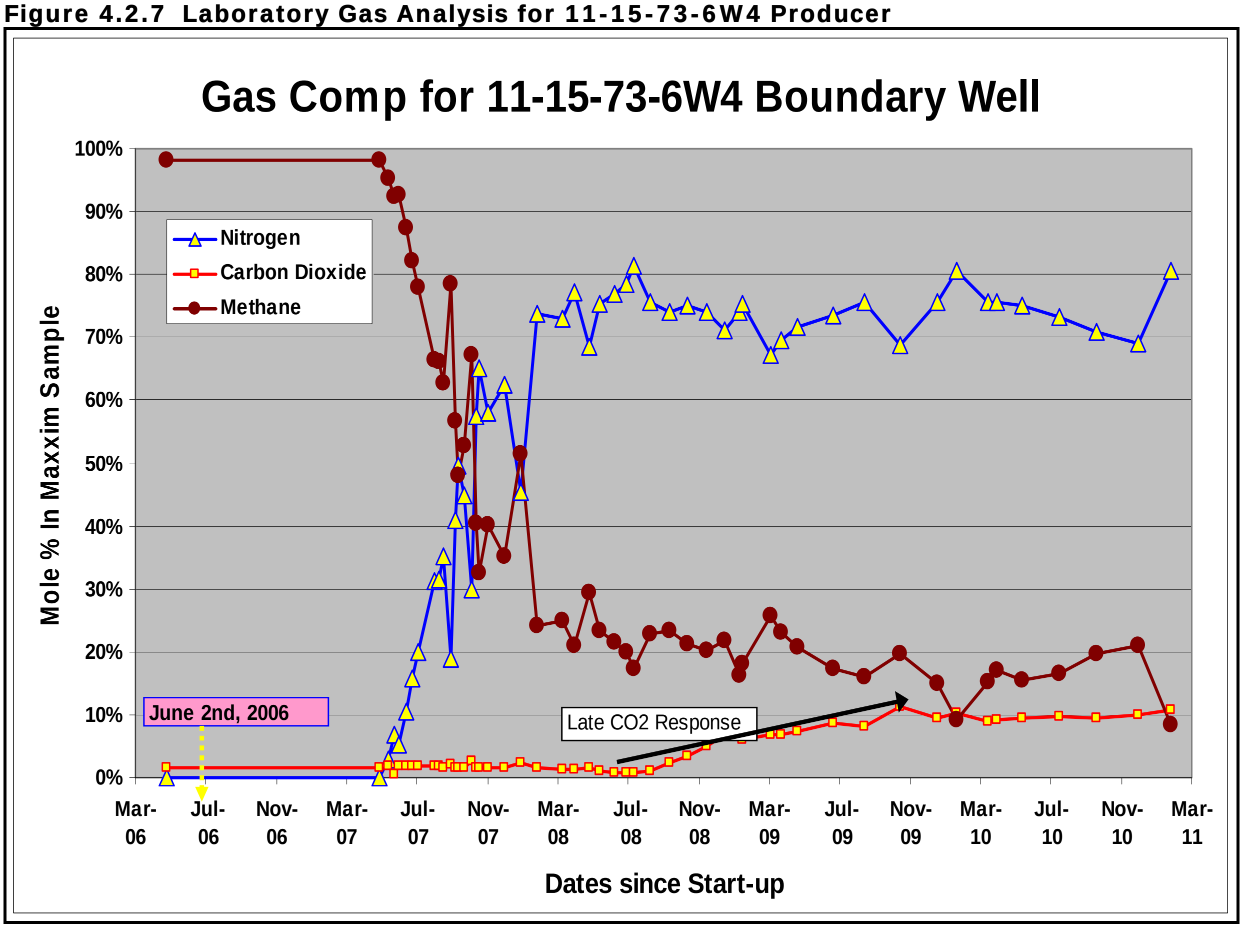


Figure 4.2.8 shows the changes in gas composition for 14-9-73-6W4 over time. Nitrogen response occurred at 14-9 starting in January 2007. By June 2007, the 14-9 Hz well exceeded 65% nitrogen and was shut-in. Nitrogen levels in excess of 80%, with carbon dioxide levels typically in 17% range were recorded during the 2010 reporting period. CO was observed during the 2010 reporting period with January 2010 reporting 0.12% and January 2011 reporting 2.30%. Due the high nitrogen level the 14-9 well is flowed only to capture gas samples for analysis.

Figure 4.2.8 Laboratory Gas Analysis for 14-9-73-6W4 Hz Producer

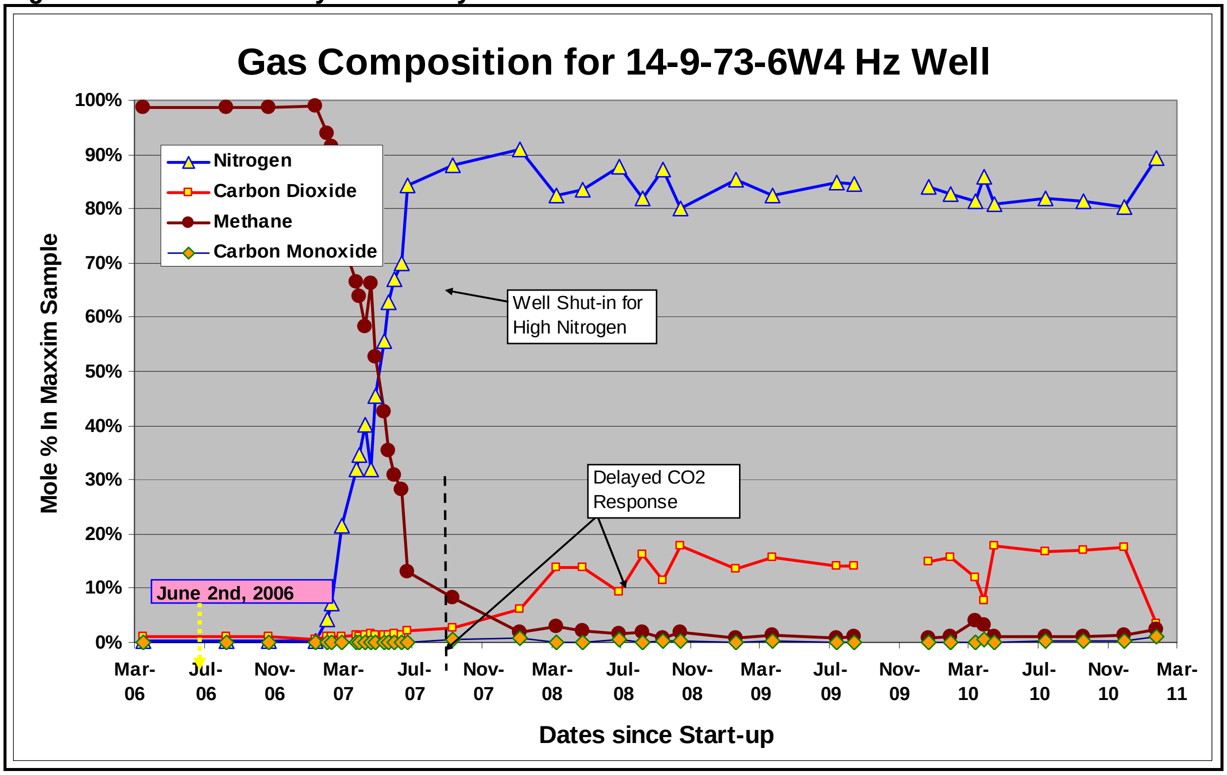


Figure 4.2.9 shows the EnCAID historical carbon dioxide levels as of January 2011. Laboratory gas sample trends appear to be showing that some carbon dioxide sequestration may be occurring.

Figure 4.2.9 Map of Carbon Dioxide Response

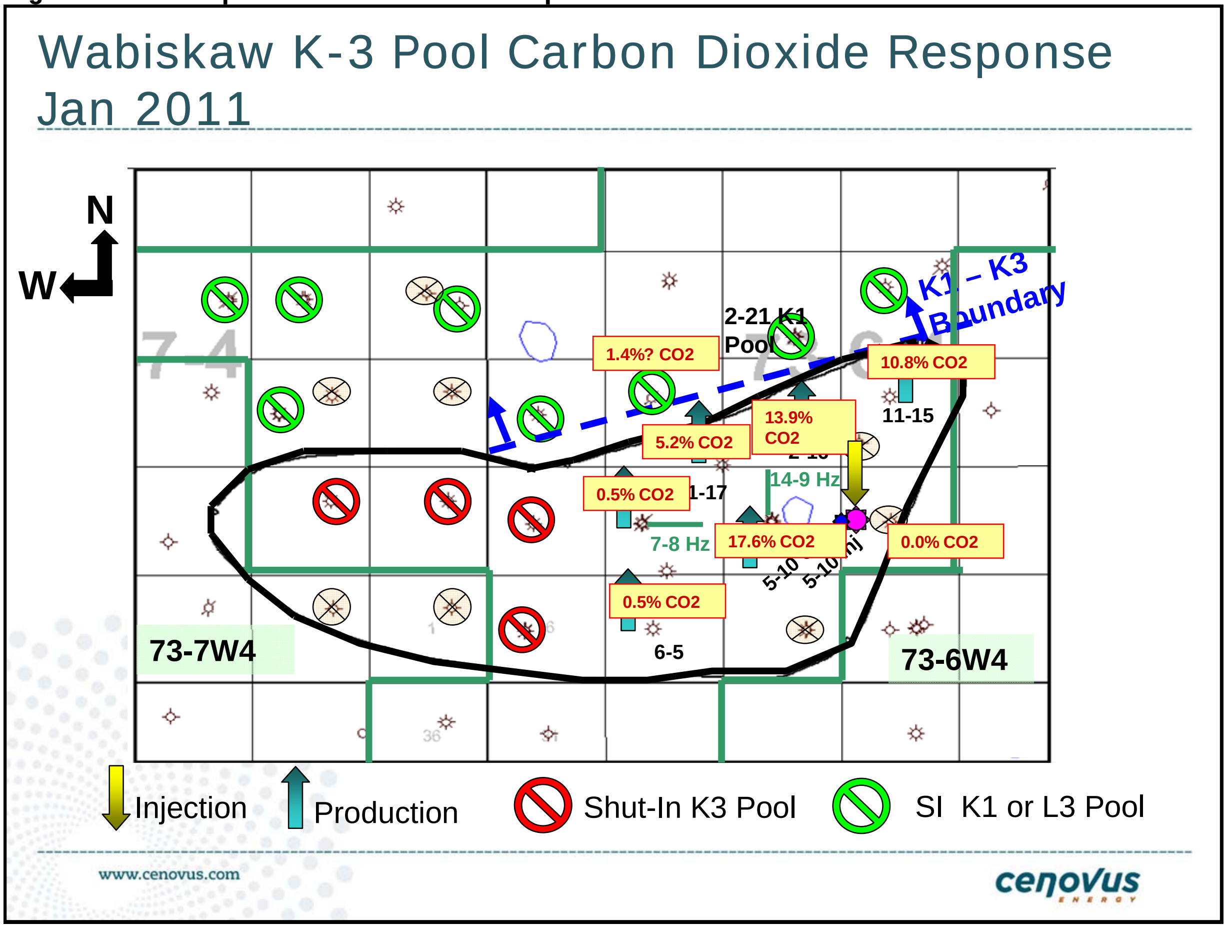
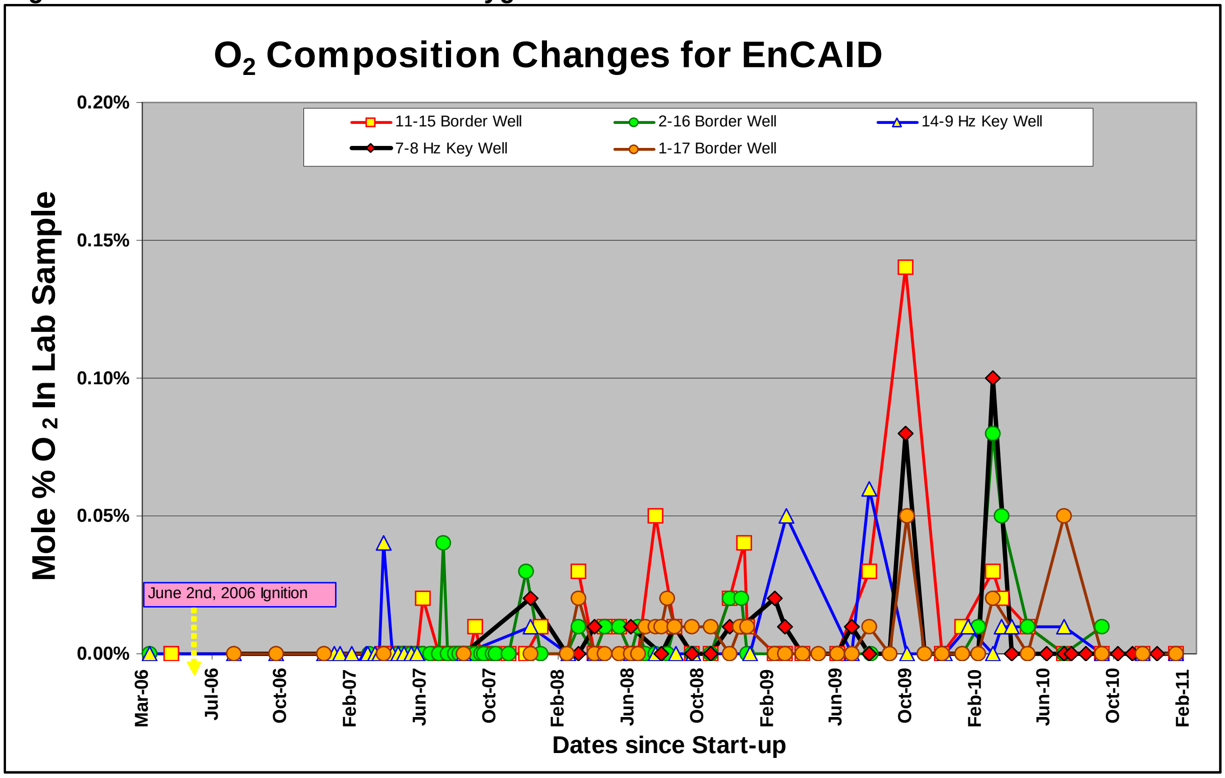


Figure 4.2.10 shows the EnCAID project historical oxygen levels. In the 2010 reporting period, all of the wells (1-17, 2-16, 6-5, 7-8, 11-15, and 14-9) had a high degree of low oxygen concentration variability. During 2010, well 1-17 had two gas samples which returned oxygen levels of 0.02 % in March and 0.05% in July, with all other months reporting oxygen levels of 0.00%. 2-16 was observed to have an oxygen level of 0.8% and 0.05% when sampled twice in March 2010, yet in all the other months the recorded oxygen levels of either 0.00% or 0.01%. The 6-5 well gas analysis indicated oxygen levels of 0.00% during the reporting period. Well 7-8 reported oxygen of 0.10% in March, however upon examination of the gas analysis this gas analysis was rejected since the nitrogen level was noted as 4.6% when historically the nitrogen had been rising at approximately 1.5% per month with February's nitrogen being 17.62% and April's being 21.35%, all the other months in the reporting period showed oxygen levels of 0.00%. In the first half of 2010 the 11-15 wells gas analysis's recorded oxygen levels ranging from 0.03% down to 0.01% before not reporting any oxygen for the balance of 2010 and January 2011. The 14-9 well recorded the highest oxygen level in March 2010 at 2.3%, however the well appears to have not been flowed for the typical 1-2 days prior to catching of gas samples, therefore that sample was discounted as all the other 2010 gas analysis returned oxygen levels between 0.00% and 0.01%.

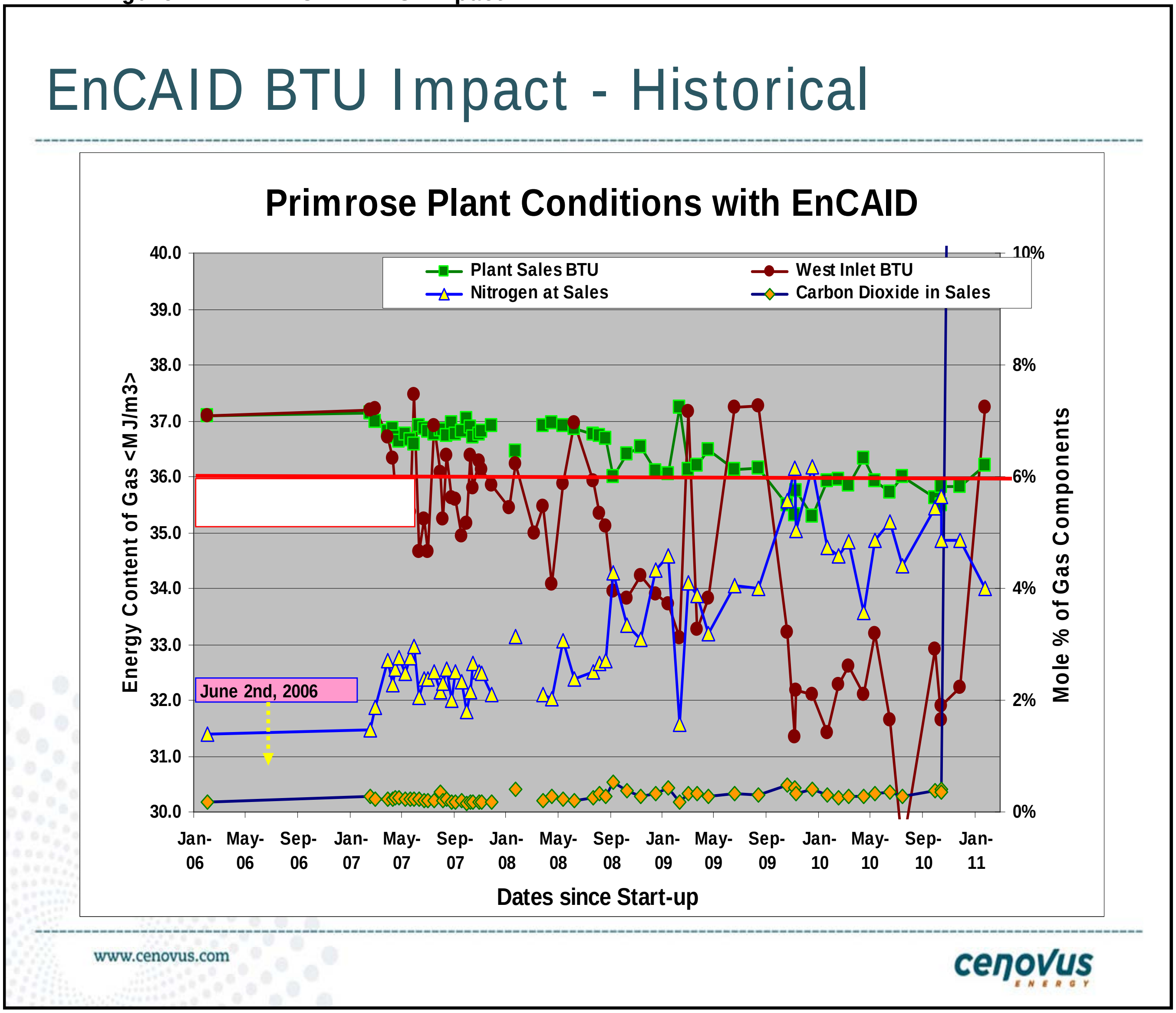
Figure 4.2.10 EnCAID Historical Oxygen Levels



H_2S analyzers are located at the Primrose North Gas Plant inlet and Cenovus continues to intermittently monitor for changes in sulphur compounds through both on-site Draeger H_2S gas measurements as well as Trace Sulphur Analysis in the laboratory. Testing has shown 1 ppm at the 14-9 Hz and 3.5 ppm at 2-16.

Figure 4.2.11 shows the impact that the EnCAID project production has had on the Primrose Plant heating values over time.

Figure 4.2.11 EnCAID BTU Impact



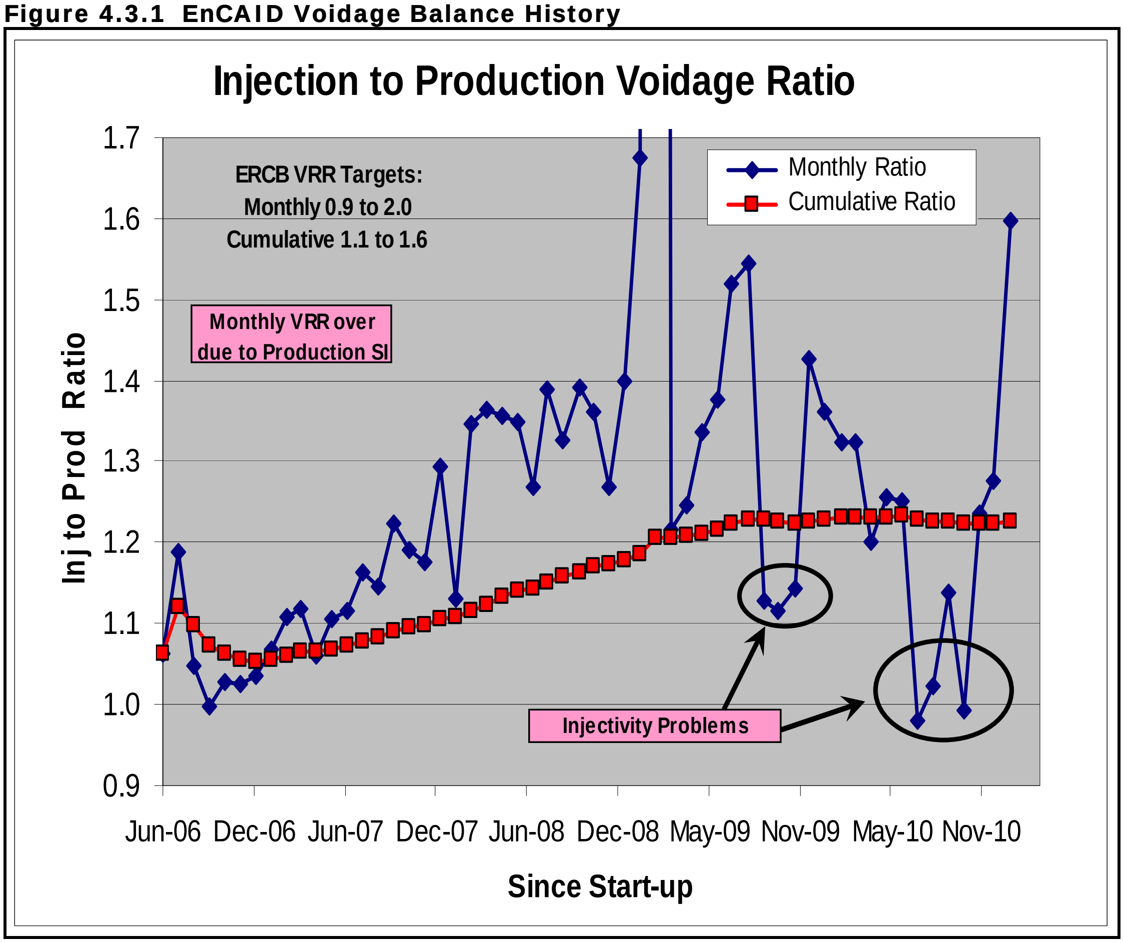
4.3 Pilot Performance

To the end of January 2011, Cenovus has injected 4.3 BCF (121 e^6m^3) of air and produced 3.5 BCF (98 e^6m^3) of gross gas for a cumulative Injection to Production ratio of 1.22. Due to the dilution effect of nitrogen breaking through to producers and continued withdrawal of high nitrogen gas at several boundary wells, the actual net formation gas withdrawal in this same period is approximately 2.97 BCF (83 e^6m^3) which represents an overall formation to bulk gas of 84%. In January 2010, the EnCAID average daily production was 0.90 MMSCFD of gross gas or 0.73 MMSCFD of actual formation gas at a daily ratio of 81.2% formation gas. These rate were lower than the balance of 2010 due to some of the production wells having been shut-in to control sales gas BTU levels.

The project performance has been well within the ERCB approval voidage replacement ratio (VRR) limits of a monthly ratio of 0.90 to 2.0 and above the minimum annual VRR of 1.0. The early 2009 non-productive period is the only time that Cenovus has exceeded the monthly ratio (as per the self-disclosure). Cenovus continues to use the gross gas production rate to design the air injection rate and voidage balance as the cycled nitrogen and combustion gases are removed from the Wabiskaw pool.

Figure 4.3.1 illustrates both the monthly injection to production voidage ratio as well as the cumulative balance since start-up. The original cumulative injection to production target of 1.1:1.0 was designed based upon a review of the "pre-EnCAID" reservoir simulation model that showed a slight increase in reservoir pressure with this replacement balance. A revised cumulative range of 1.1 to 1.6 granted in ERCB approval 10440F has allowed Cenovus to move forward with the process and exceed the original cumulative ratio to observe the relative pressure increase.

Figure 4.3.1 EnCAID Voidage Balance History



Cenovus received several amendments to the ERCB approval to supply more operational flexibility to utilize available compression capacity to achieve the cumulative ratio target and allow for higher air rate testing. These revisions have taken the monthly ratio range up from the original application values of 0.9 to 1.1 to a range of 0.9 to 1.40 and finally up to as high as 2.0 to allow Cenovus to reach and exceed the desired 1.1 cumulative voidage value.

4.4 Injection, Production, Observation Well and Reservoir Pressure History

Figure 4.4.1 shows the reservoir pressure in the Wabiskaw K-3 pool prior to commencement of injection in winter 2006. Figure 4.4.2 shows the net pressure changes and reservoir pressure in the Wabiskaw K-3 pool at the end of January 2011.

Figure 4.4.1 Wabiskaw K3 Reservoir Pressure Before Injection

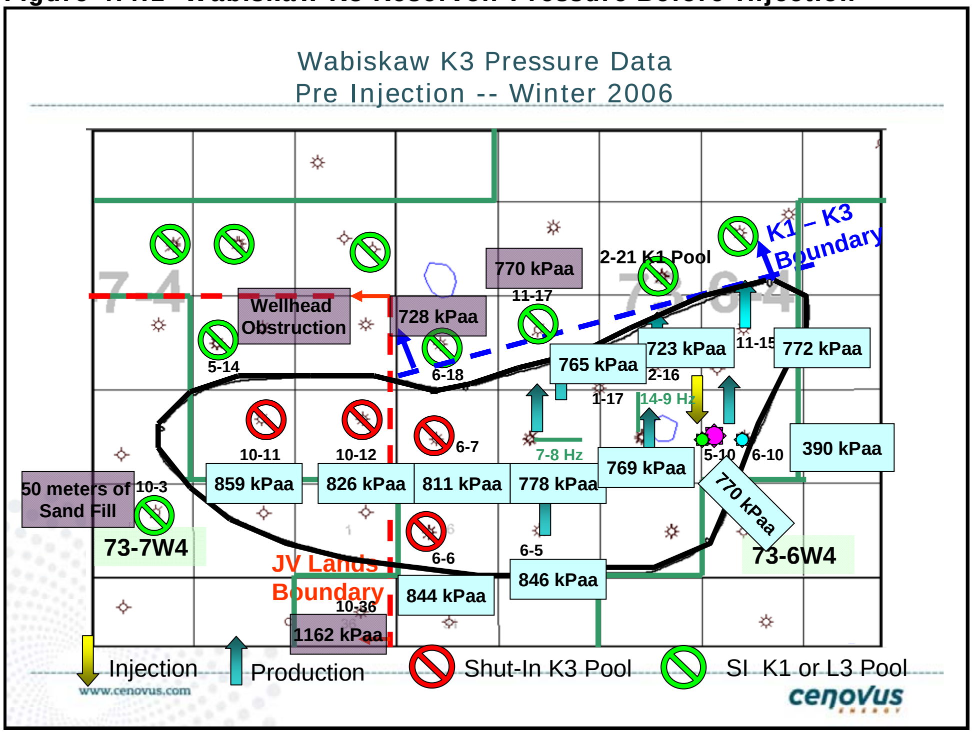
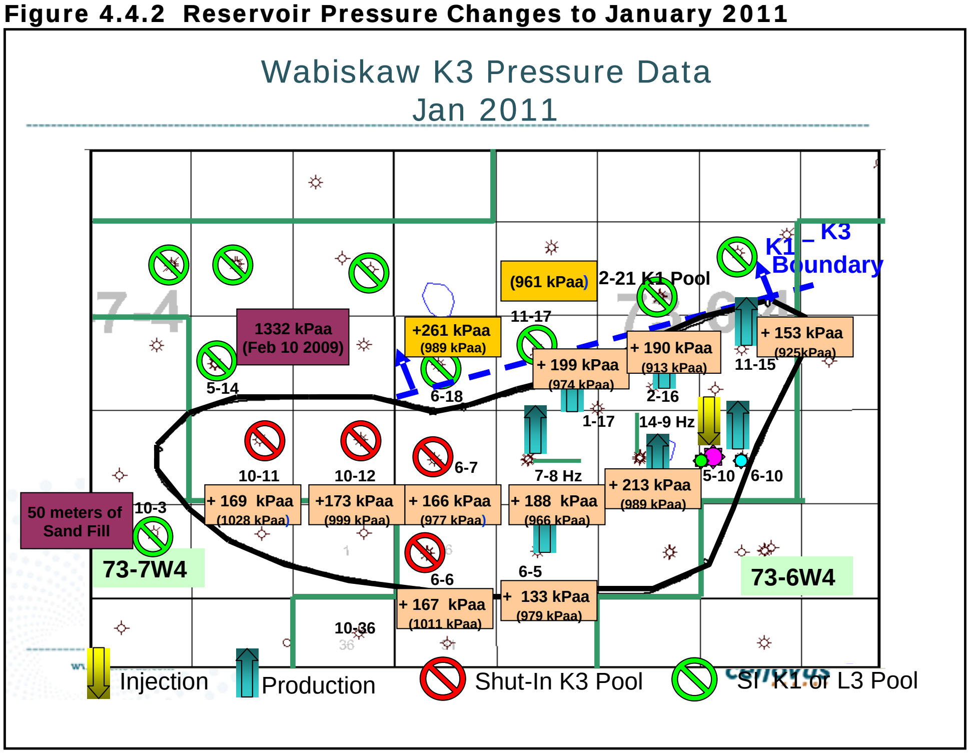
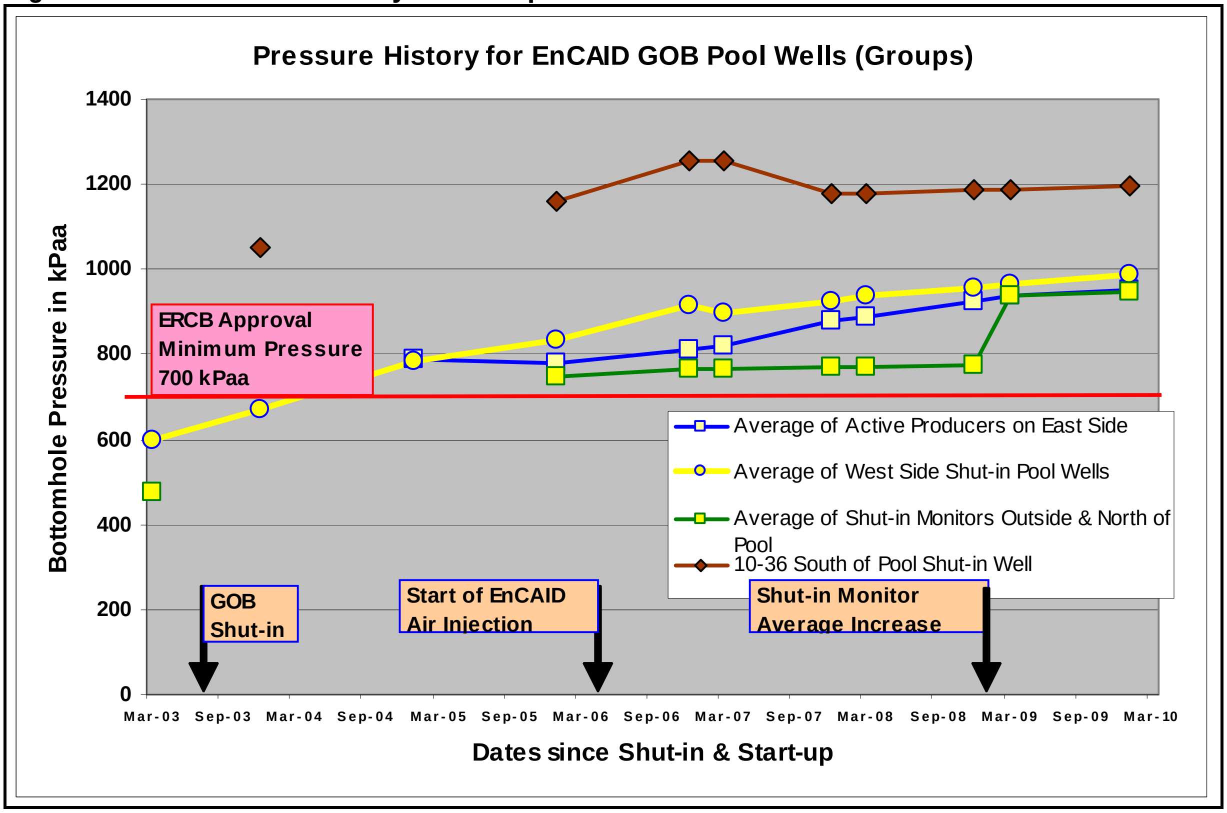


Figure 4.4.2 Reservoir Pressure Changes to January 2011



As shown in Figure 4.4.3, since start-up the average pressure change in the EnCAID flooded area is over 180 kPaa with the West shut-in part of the pool having a pressure increase of about 170 kPaa. Overall, as designed, the EnCAID process and natural recharge from low permeability areas have increased the reservoir pressure to 960 kPaa to January 2011.

Figure 4.4.3 Pressure History for Groups of EnCAID Wells

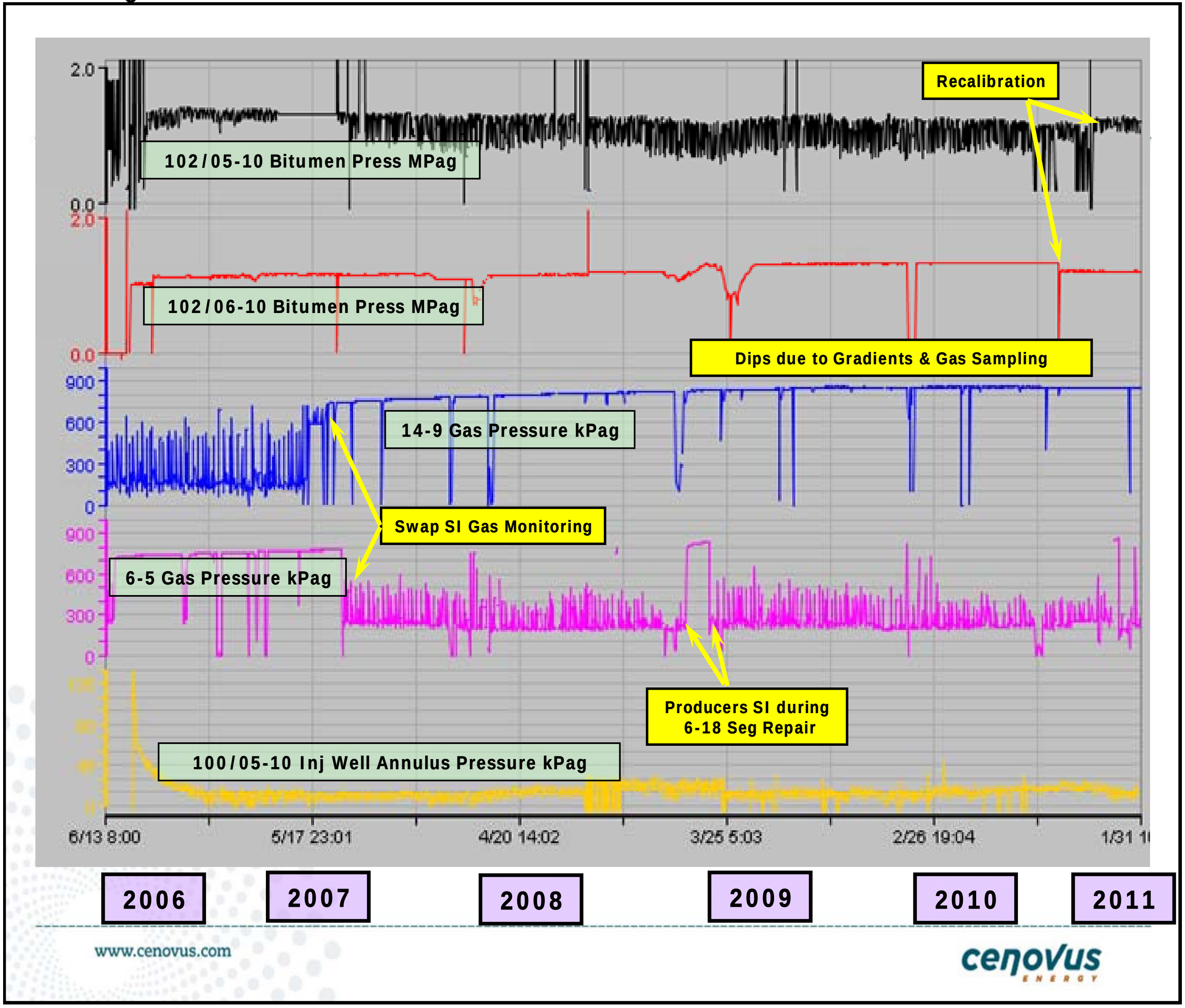


The static gradients of December 2008 detected an anomalous pressure trend at the one “out of pool” monitoring well 6-18-73-6W4 with the pressures declining and reaching a level of 641 kPaa. With this movement below the ERCB minimum sandface pressure of 700 kPaa, all of the EnCAID producers were shut in on January 19, 2009. The rest of the pressure monitoring was showing all of the EnCAID K-3 Pool wells above 900 kPaa so this was deemed by Cenovus to be an anomalous data point. In a second segregation test on the non-producing Wabiskaw & Colony well 6-18, Cenovus detected a communication between the zones leading to pressures closer to the Colony level of 600 kPaa. Following a service rig repair of this well in February 2009, a static gradient on 6-18-73-6w4 showed a compliant Wabiskaw pressure of 939 kPaa, leading to the reactivation of all of the EnCAID producers.

The continuous surface pressure monitoring at the 14-9-73-6W4 well is showing a steady rise in pressure from an initial reading of about 644 kPag to a current reading of 866 kPag (end of January 2011). This surface pressure at 14-9 would translate to a bottomhole pressure estimated to be 991 kPaa, assuming 32 kPa for the gas head and 93 kPa for the conversion to absolute pressure. These values were verified with a January 2011 static gradient showing a downhole MPP pressure of 989 kPaa which is above the Approval minimum stabilized bottomhole pressure of 700 kPaa.

Figure 4.4.4 shows the bitumen piezometer pressures at 6-10-73-6W4 and 102/5-10-73-6W4. At 102/5-10-73-6W4, the bitumen piezometer 3 meters below the gas-bitumen interface had averaged 1.15 MPag while the gas zone shut-in pressure is around 960 kPag. The temperature has decreased at the piezometer location from 201C down to 176C. For the 6-10-73-6w4 fringe gas well, the bitumen piezometer 22 meters below the gas-bitumen interface has remained steady at 1.2 MPag.

Figure 4.4.4 Bitumen & Gas Pressures at Producers



Cenovus interprets that the EnCAID low pressure gas displacement process is not showing any significant effects on the bitumen zone pressure in the majority of the reservoir. However, we are observing the bitumen pressure approaching the rising gas zone pressure where the temperature into the bitumen has been stimulated to above 100 deg C. In this case, the enhanced fluid mobility similar to SAGD maybe creating some pressure movement.

Overall, the EnCAID process has proven to be able to operate and replace formation gas while demonstrating a slight pressure increase and staying significantly above the 700 kPaa limit for the Wabiskaw K-3 Pool as described in the ERCB Approval 10440.

5. Pilot Data

5.1 Additional EnCAID Project Data and Interpretation

5.1.1 Geology

An observation well was jointly drilled in the first half of 2006 by Petro-Canada (now Suncor Energy) and Cenovus at 102/5-10-73-6W4, 30 meters west of the 100/5-10-73-6W4 injection well. A total of 35.6 meters of core was recovered from 2 meters of shale, 5 meters of gas, 28 meters of bitumen and 2 meters of bottom shale. Overburden analysis conducted at 1000psi for 15 samples were taken at roughly 3m intervals through the gas and bitumen zones to include density, porosity, kmax, kv and Dean Stark saturations. A further 39 Dean Stark samples were highly concentrated within the gas zone and down to 18 meters below the gas-bitumen interface.

In 2009, a particle size analysis of 10 solid samples were conducted using the same 102/5-10 observation well. A sampling interval of 3 to 5 meters was used to achieve an even distribution through the bitumen zone. The samples were analyzed using a "Coulter LS" Laser Diffraction particle size analyzer.

All core photos and core analysis can be found in **Appendix A and Appendix B**.

Core photographs shows a 3.5 meter thick gas zone containing small amounts of residual oil saturation followed by a thick underlying bitumen saturated Wabiskaw with occasional thin shale lenses and calcium carbonate tight streaks. A small core loss at the top of the gas zone can be observed due to the unconsolidated nature of the formation. Dean Stark and small plug analysis conducted show average porosities and horizontal permeabilities of 35% and 1350mD. The best rock quality occurs in the gas zone where permeabilities can increase up to 3000mD, reflecting a slightly coarser grain size in this zone as seen in the particle size analysis. Oil saturations derived from the combination of core analysis and detailed petrophysical analysis are on average 15% in the gas zone and 61% in the bitumen zone.

5.1.2 Oil Composition

Using the obtained core at 102/5-10, a sample taken 2 meters below the gas-bitumen interface was selected for oil extraction to determine the density and viscosity at three different temperatures (13C, 75C and 150C) and two different pressures (800kpag and 2500kpag).

Further SARA oil and full oil analysis were conducted on three samples located in the gas zone, directly below the gas-bitumen interface and 10m below the gas-bitumen interface. The sampling involved V notching in the gas zone and 0.4 meter long samples around each bitumen zone to obtain sufficient rock sample for oil extraction.

Full oil analysis can be found in **Appendix C.**

Viscosity and SARA asphaltene composition measurements found no substantial variation in the oil properties with depth

5.1.3 <u>Simulation & Results</u>

Several simulation efforts have been made since project inception:

5.1.3.1 Areal Simulation Model for Scoping
5.1.3.2 Near-Wellbore Simulation Model
5.1.3.6 Full Field 3D Dual Grid Model
5.1.3.4 Detailed Near-Wellbore Combustion Front Model

5.1.3.1 Areal Simulation Model for Scoping:

The initial model using the CMG STARS thermal simulator was developed in the summer of 2004 by Dr. Ben Nzekwu, using petrophysical results for both the Cenovus defined Wabiskaw K-3 Pool and a greater region adjacent to EnCAID within the AEUB defined Kirby Upper Mannville I Pool. Incorporation of all of these reservoir & geological properties would allow gas flow outside the Cenovus defined K-3 pool IF the fluid dynamics and physics dictated that movement should take place. This model was built before construction and operations started in the field. This initial model handled three gas layers with a large bitumen layer to forecast overall process performance after initially history matching the existing gas production and pressures. The overall model involved 40 meter x 40 meter x 3 variable thickness gas layer grid blocks covering a Wabiskaw Field area of 12 kilometers by 8 kilometers. This model provided the original long term forecasts for EnCAID in the early stages (3.5 to 4 years) and the end of project nitrogen & methane profiles at 16+ years (2022), and is shown in Figure 5.1.1 and 5.1.2. It was useful for gas movement simulation and total gas recovery, but didn't capture the actual combustion front with a lot of detail. This model is presented in Appendix D – Long Term Simulation. The initial inputs are shown in Appendix D – Simulation Model Input.

Figure 5.1.1 Pre-EnCaid Areal Simulation Model; Early-stage nitrogen profile

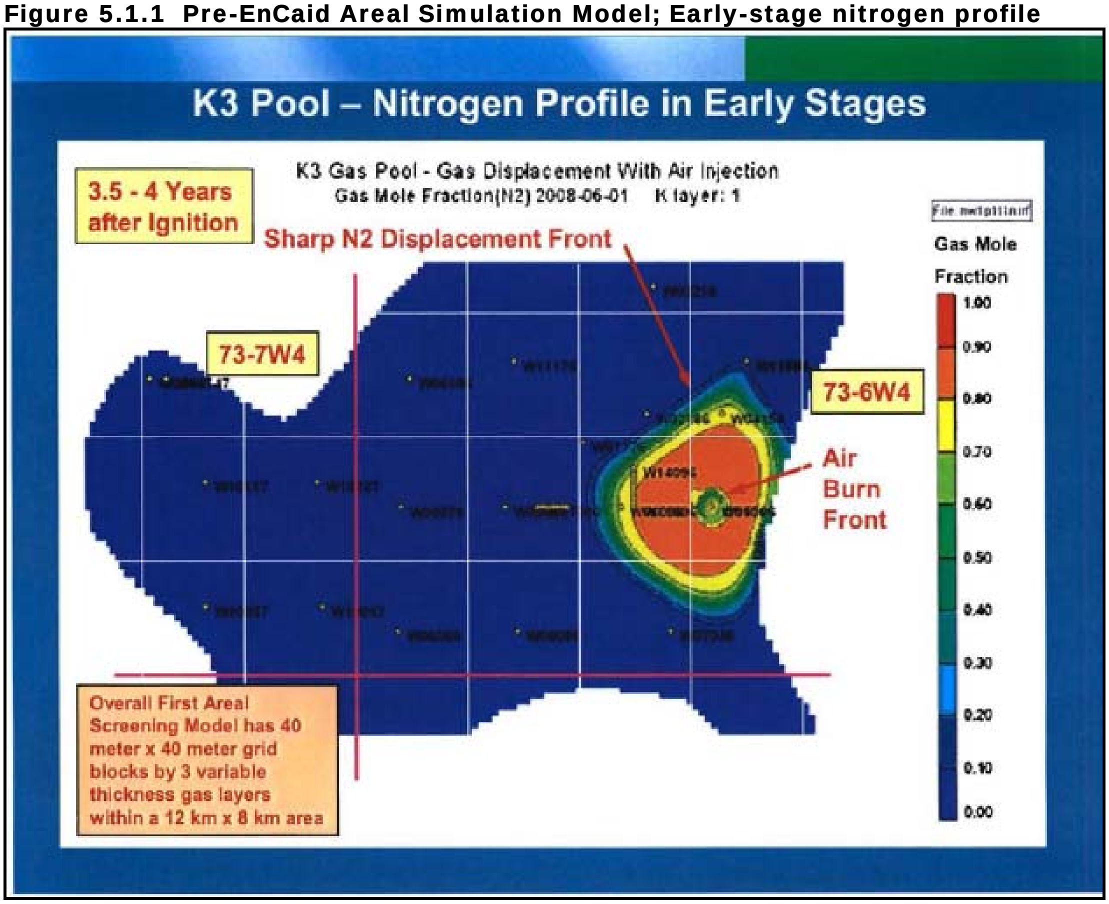
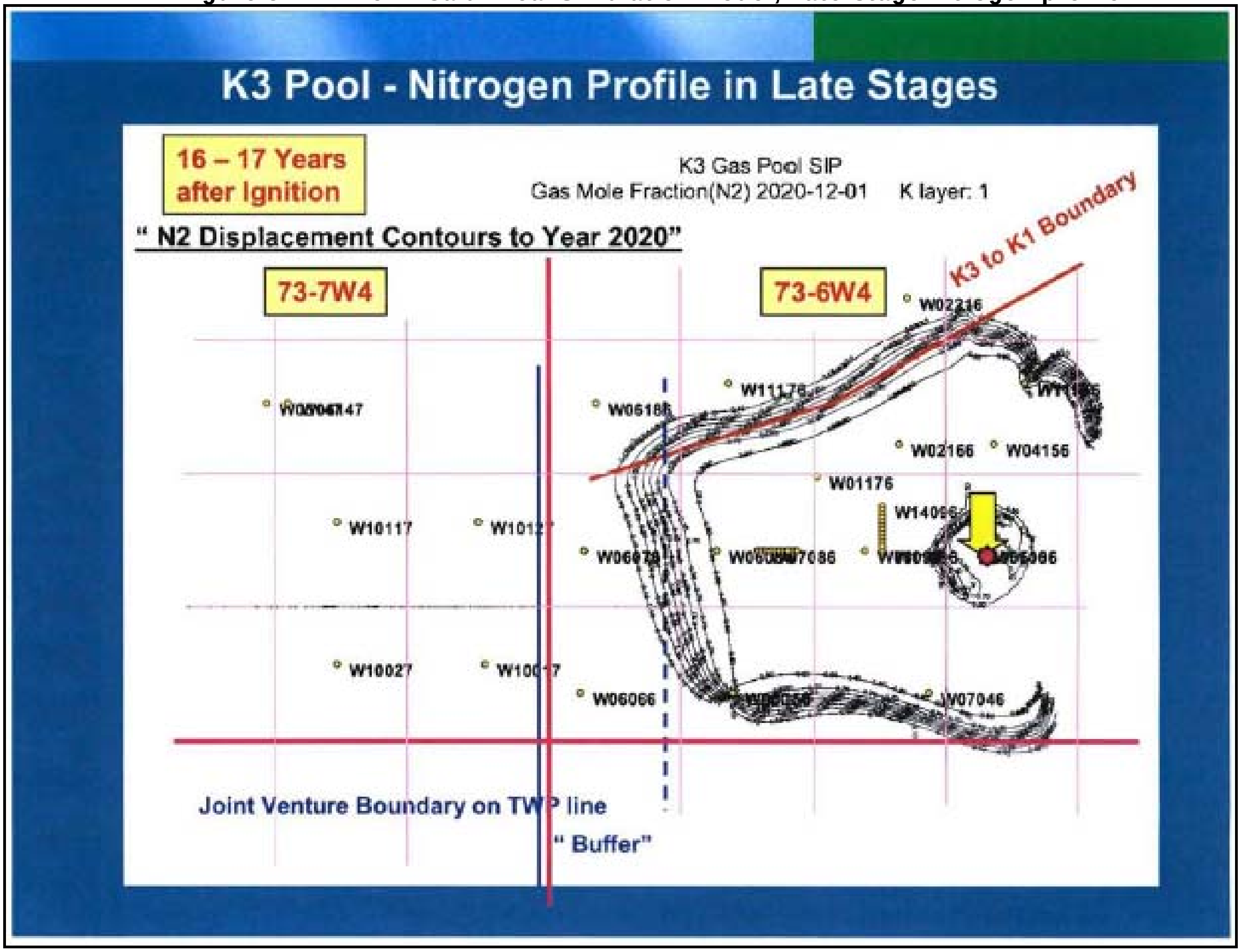


Figure 5.1.2 Pre-EnCaid Areal Simulation Model; Late-stage nitrogen profile



5.1.3.2 Near-Wellbore Simulation Model:

During the AEUB application process and in anticipation of start-up procedural questions, the first model was modified and refined to handle an approximately 3000 meter by 3000 meter square area around the 100/5-10-73-6W4 injection well utilizing 3 meter x 3 meter x 3 variable thickness gas layer grid blocks (Figure 5.1.3 and 5.1.4). This model was built before construction and operations started in the field. It provided an estimate of the combustion front size and was utilized in the decision on where to place the joint Suncor and Cenovus observation well. The observation well was placed 30 meters to the west of the 100/5-10 injector to supply temperature & pressure results. This model is detailed in Appendix D – Short Term Simulation.

Figure 5.1.3 Pre-EnCAID near-wellbore simulation model; thermal impact on bitumen

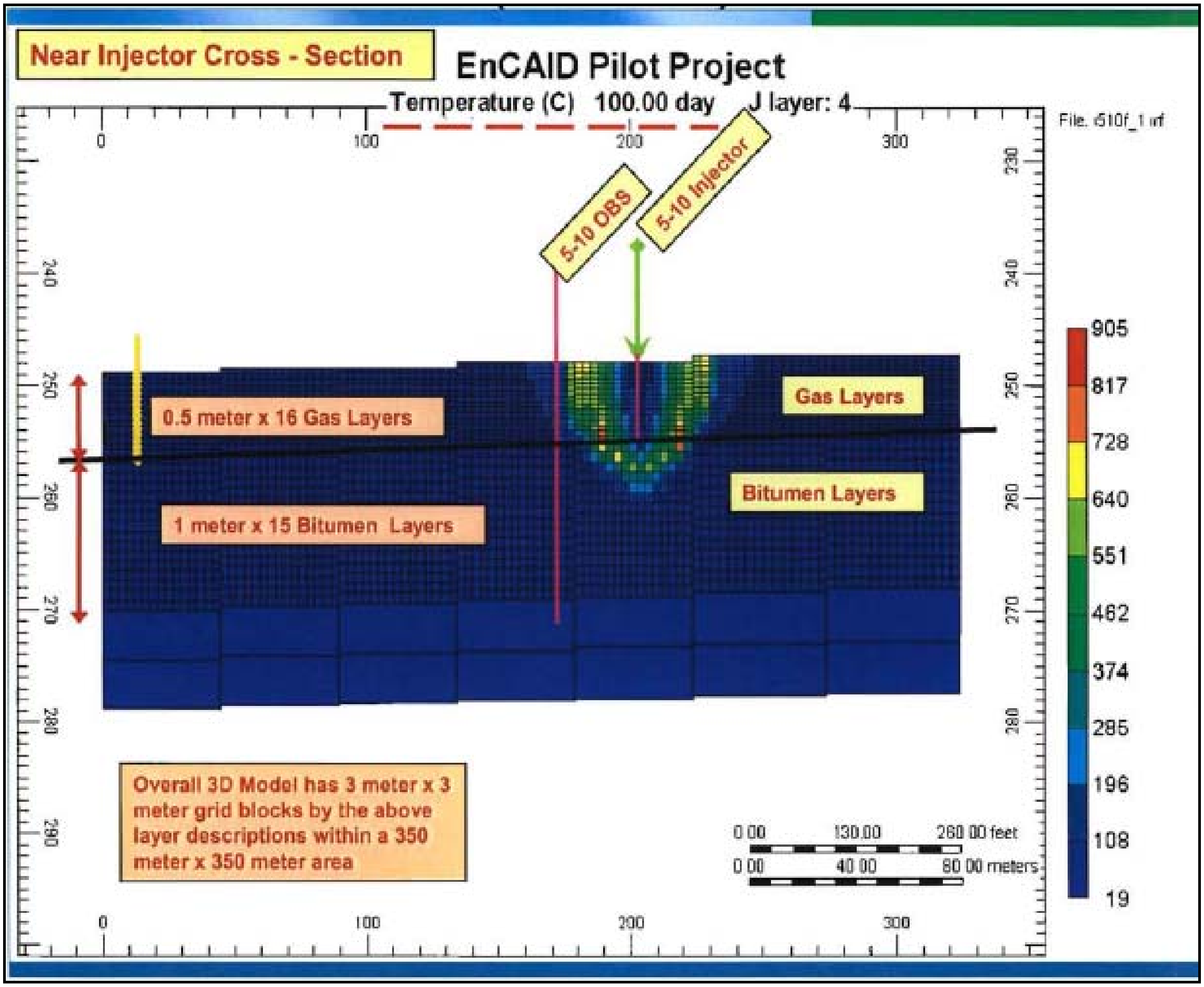
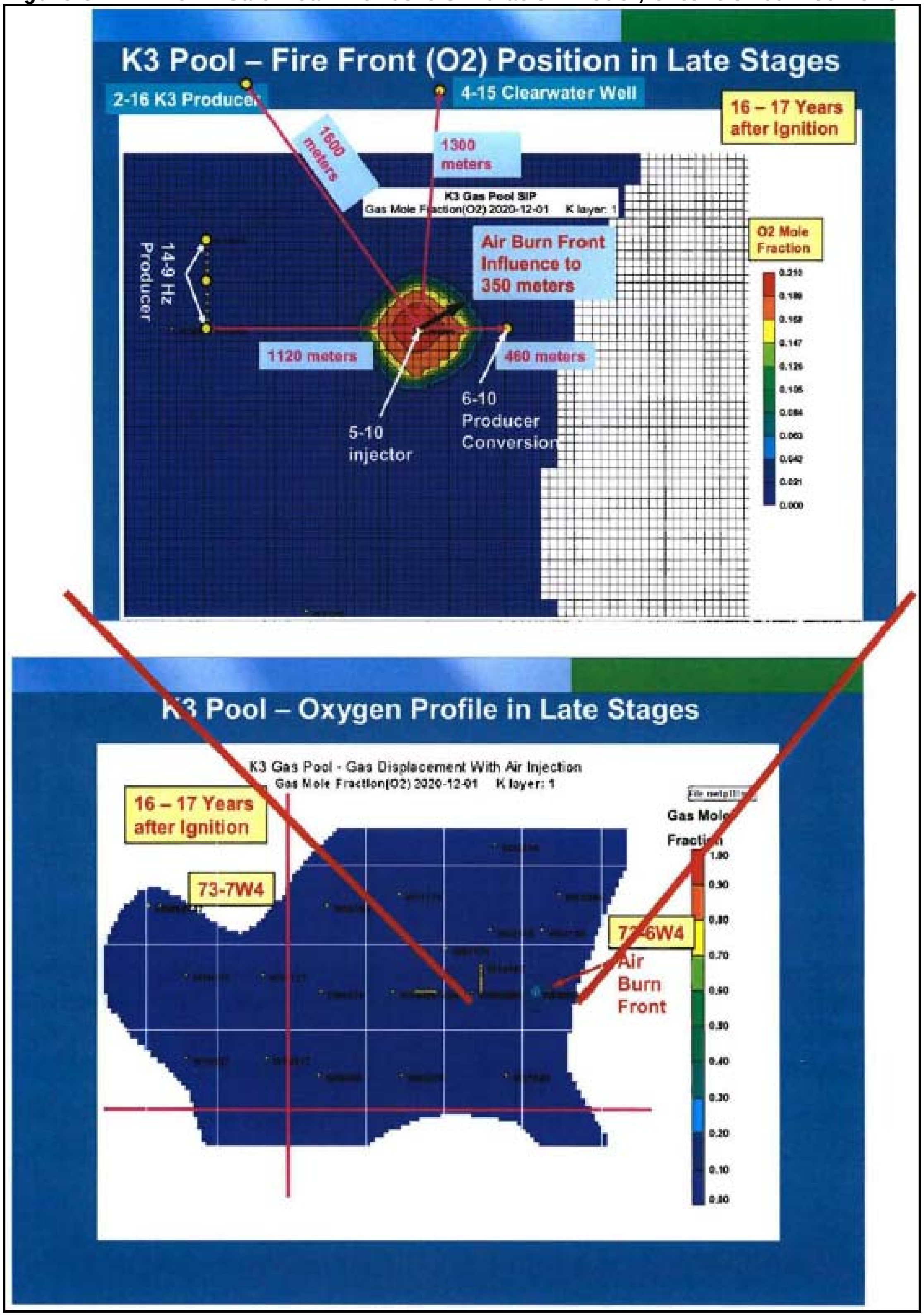


Figure 5.1.4 Pre-EnCaid near-wellbore simulation model; extent of burned zone



5.1.3.3 Full Field 3D Dual Grid Model:

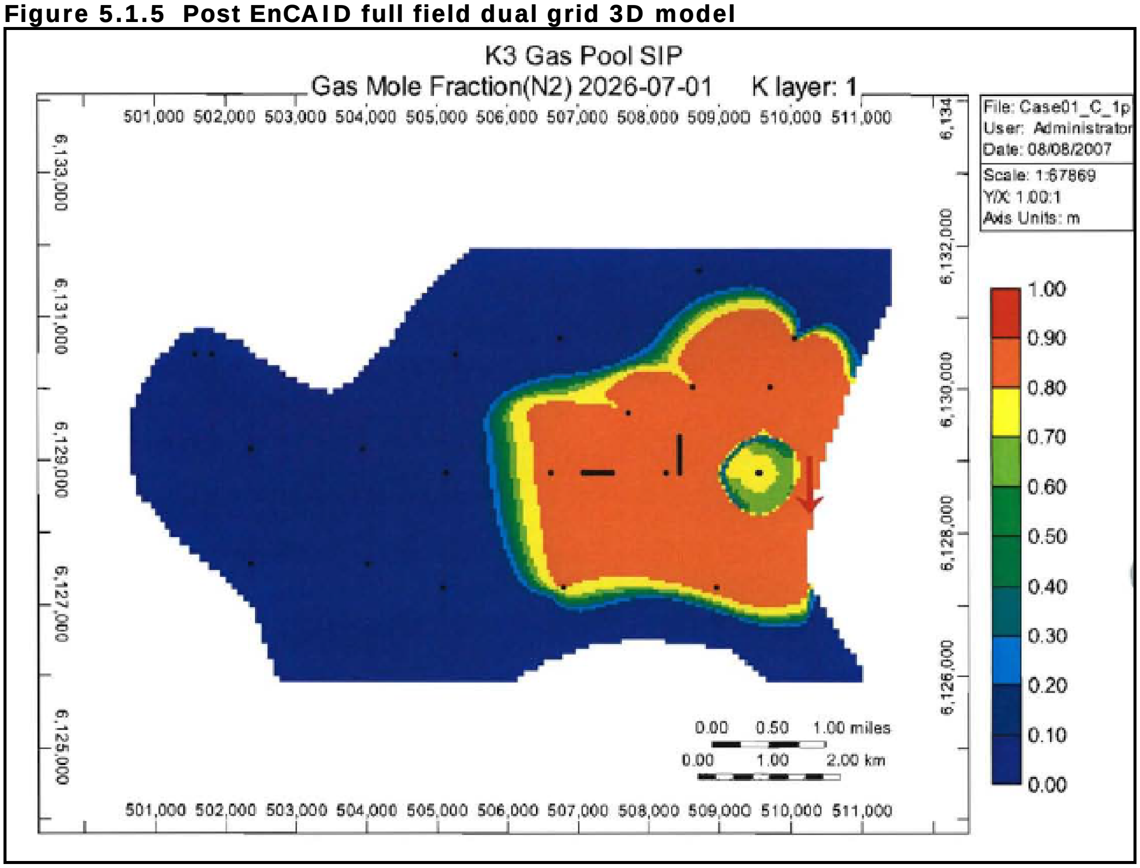
The final detailed version of the model involves a higher resolution multilayer simulation of the region about 500 meters from the injector. The area close to the injector has 3 meter x 3 meter gas grid blocks that are 0.5 meters thick (16 layers) as well as 15 bitumen layers of 1.0 meters each. The model honours thickness and structural changes to allow the detailed view of any temperature and fluid influx into the bitumen zone.

Large scale field results compare directionally to both the original and latest version of the model. The gas sweep and nitrogen breakthrough was appropriately modeled, and show a relatively sharp flue gas – methane boundary. Total gas recovery was shown to reach 100% in the model. However, this involved operating wells at low methane concentrations. In reality, it is expected that the true recovery factor will approach 90%.

The peak temperature response time at the 102/5-10-73-6W4 observation well occurred at about 200 to 210 days rather than the 100 to 120 days forecasted. In addition, the peak temperature was much higher in the model than that observed in the field (396 °C).

Figure 5.1.5 depicts the full field model, showing both the combustion front and the gas sweep. The 5-10 observation location has shown temperatures as high as 396 deg C in the top of the gas zone which is well above the maximum steam temperature of 280 deg C and firmly indicates the generation of heat within the Wabiskaw K-3 formation.

Figure 5.1.5 Post EnCAID full field dual grid 3D model



5.1.3.4 Detailed Near-Wellbore Combustion Front Model:

Cenovus staff, Mr. Matt Toews in Reservoir and Mr. Jonah Resnick in Geology, created and incorporated the geostatistical Model in Figure 5.1.6 into a new 3D CMG STARS thermal simulation model of EnCAID. This history match of EnCAID was continued from the initial work of Dr. Kenny Adegbesan at KADE Technologies and incorporated some of his findings on the sensitivity to different reaction parameters and the shortcomings of the initial geological/reservoir model. This new model was built to understand the combustion front in more detail, specifically to understand the shape, temperature profile, and impact on bitumen (Figure 5.1.7 – 5.1.8). Mr. Toews was able to get the correct reaction kinetics and reservoir properties to show the proper general trends in formation temperature as well as display the correct physics/mechanics to see the double peak temperature response (on a very refined test grid – Figure 5.1.9). There were also some interesting findings on what dictates the shape of the combustion front. This model is presented in Appendix D – 3D History Match Work.

Figure 5.1.6 Detailed Near Wellbore Combustion Front Model; Geology

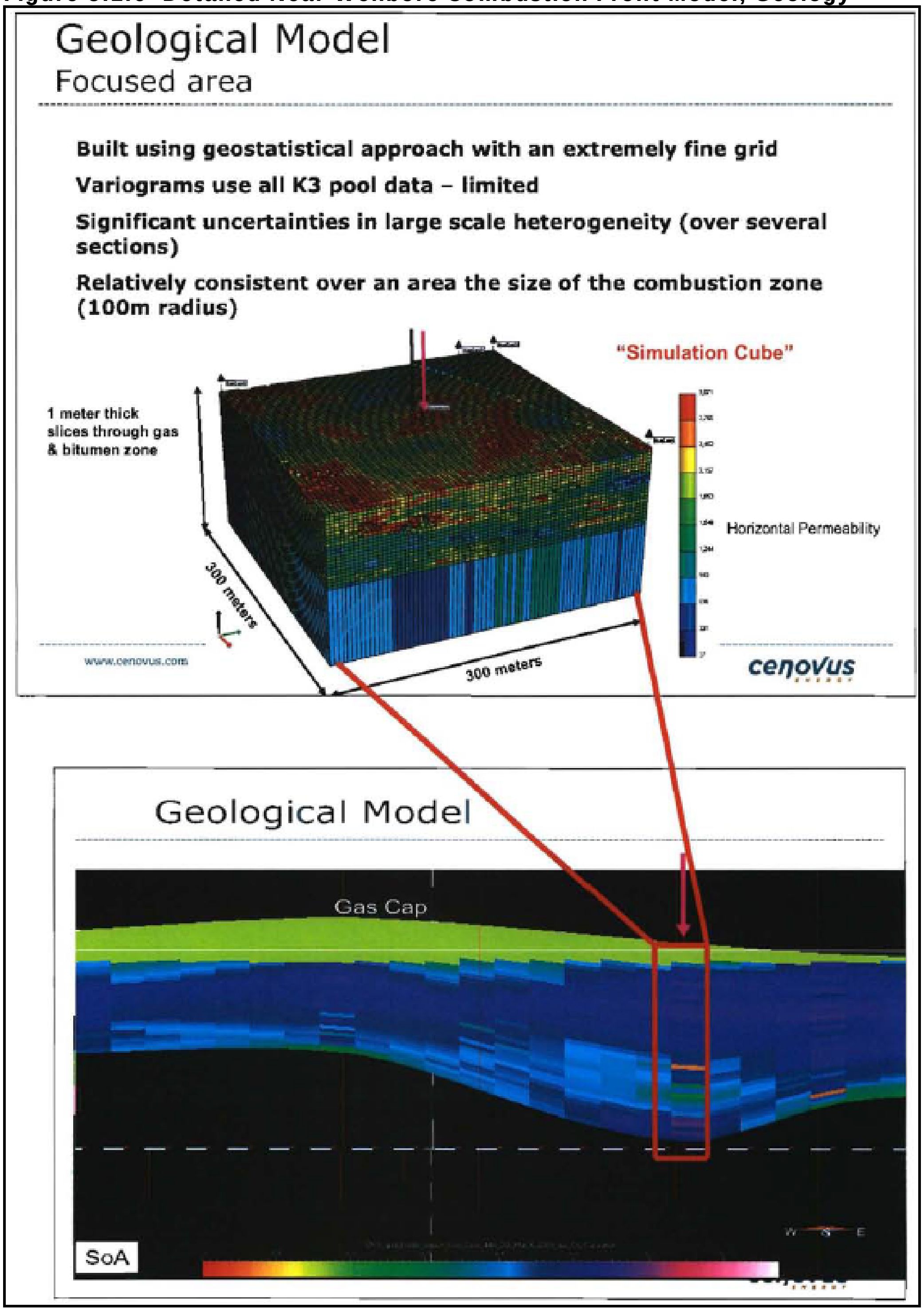
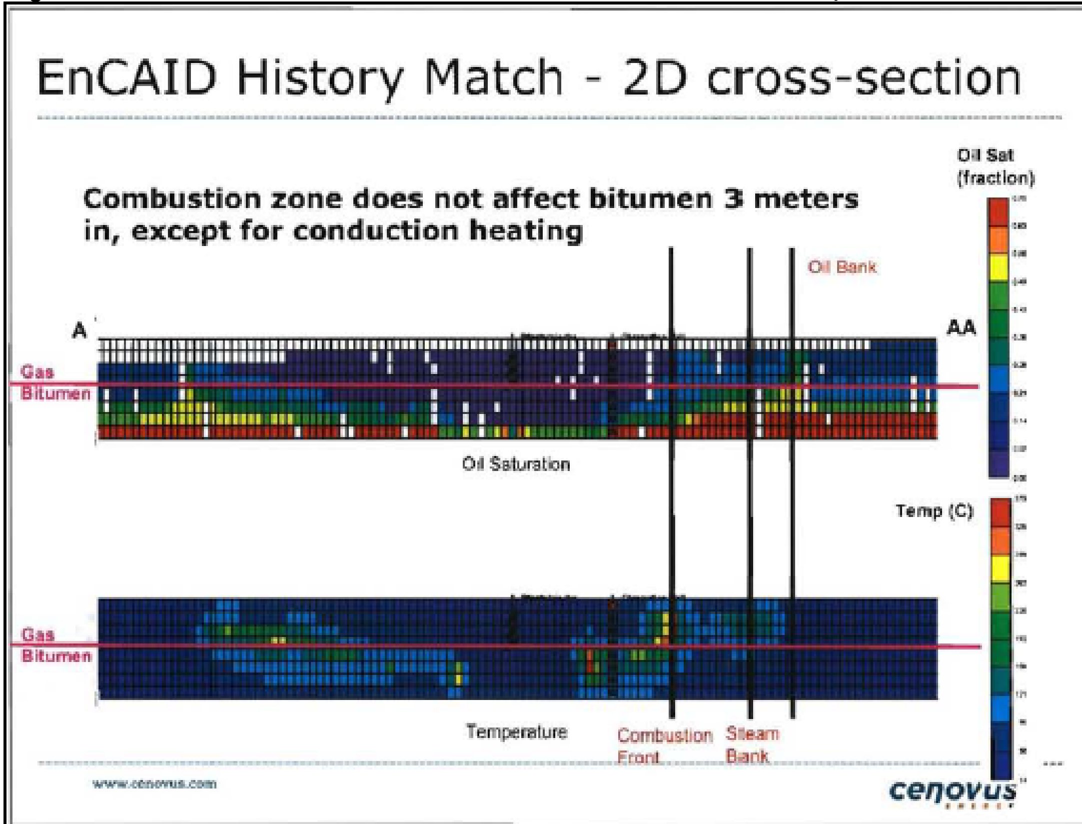


Figure 5.1.7 Detailed Near Wellbore Combustion Front Model; cross-section



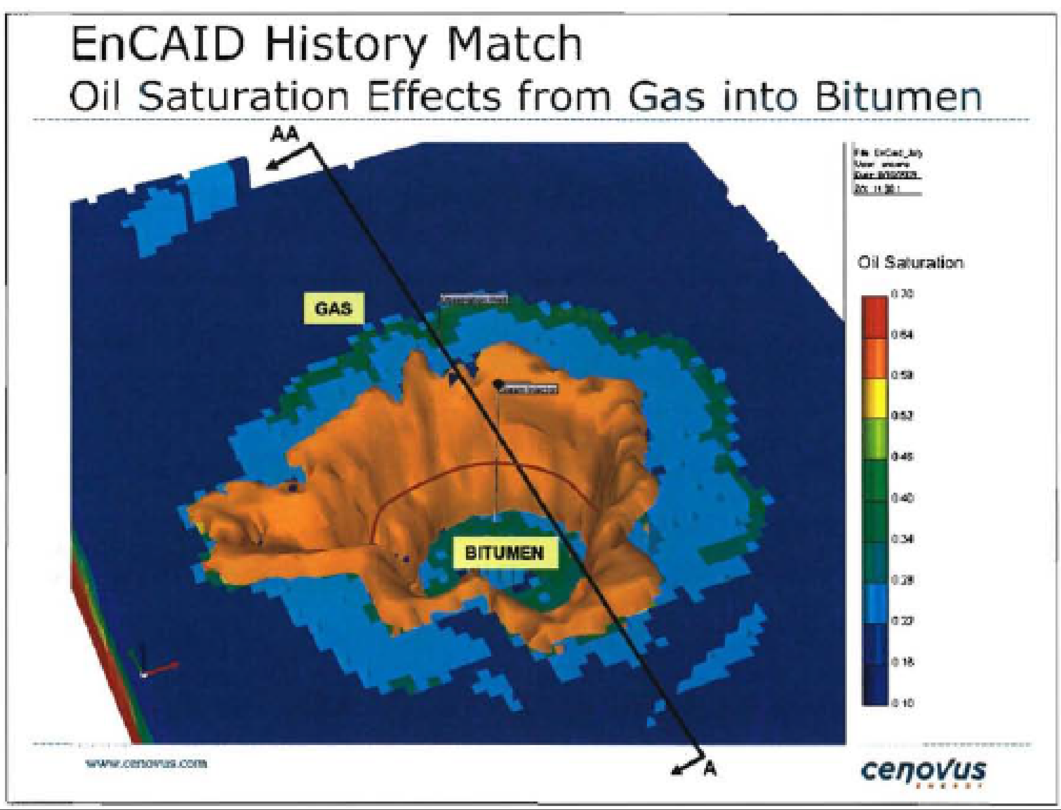


Figure 5.1.8 Detailed Near Wellbore Model; 5-10 temperature match

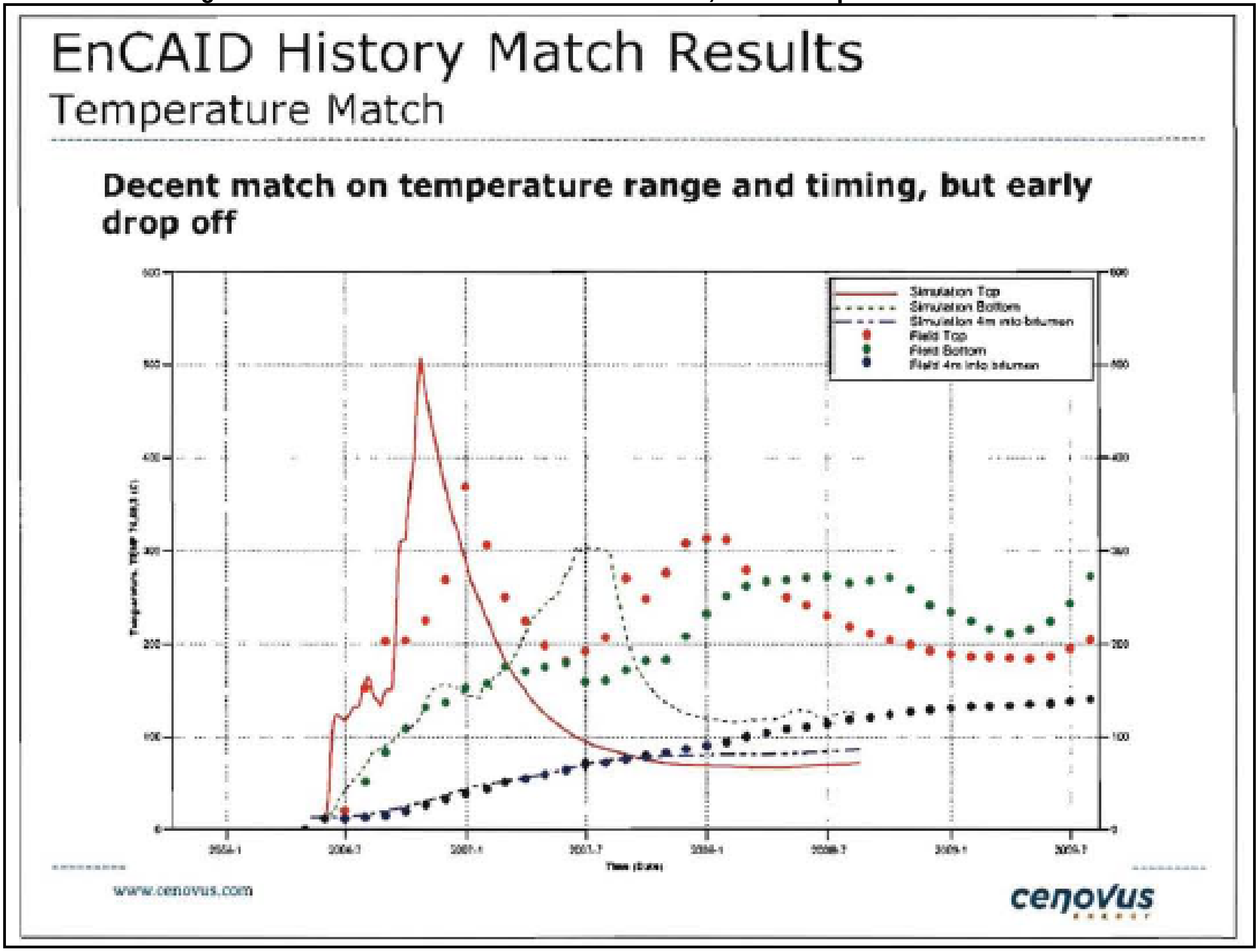
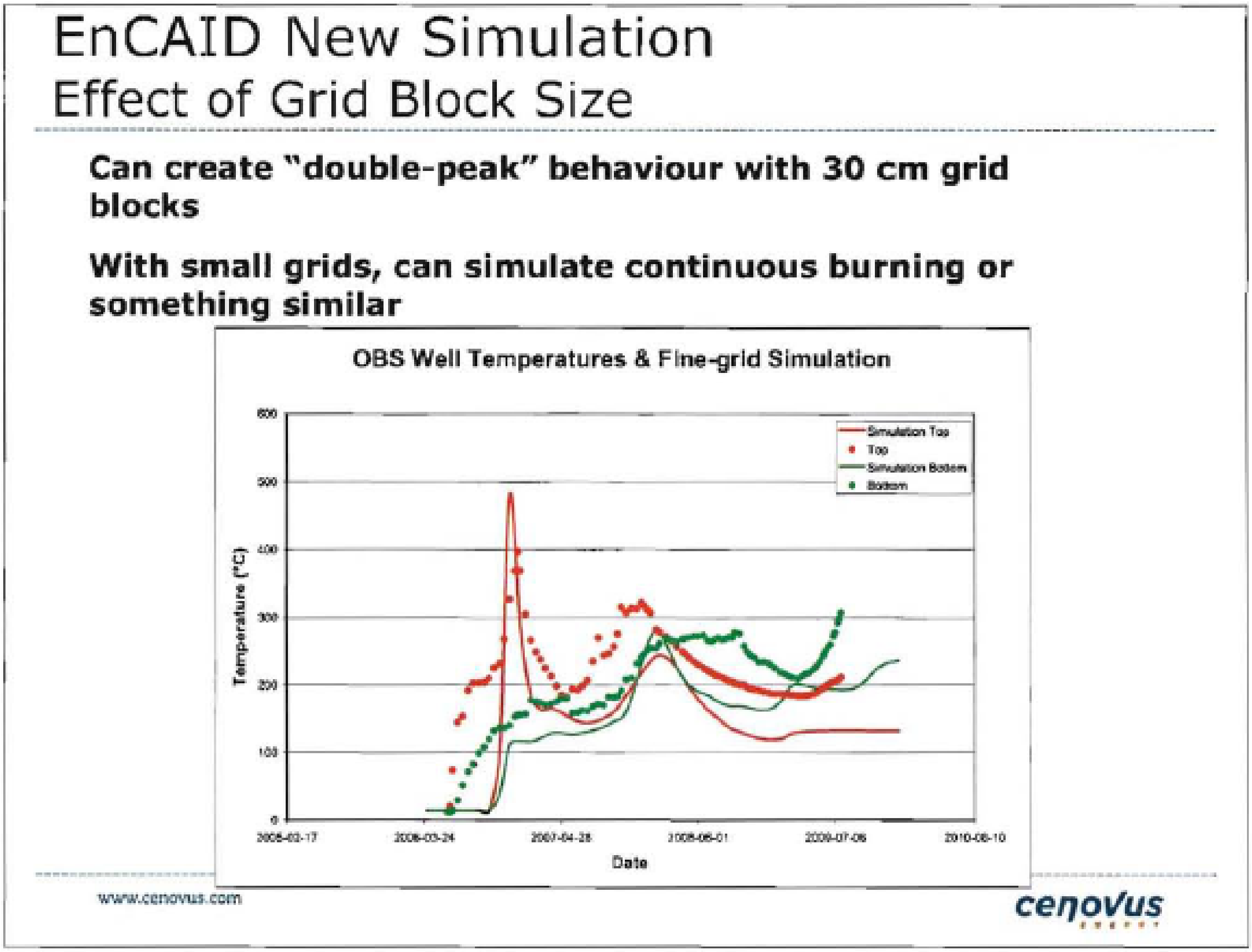


Figure 5.1.9 Detailed Near Wellbore Model; refined grid temperature profile

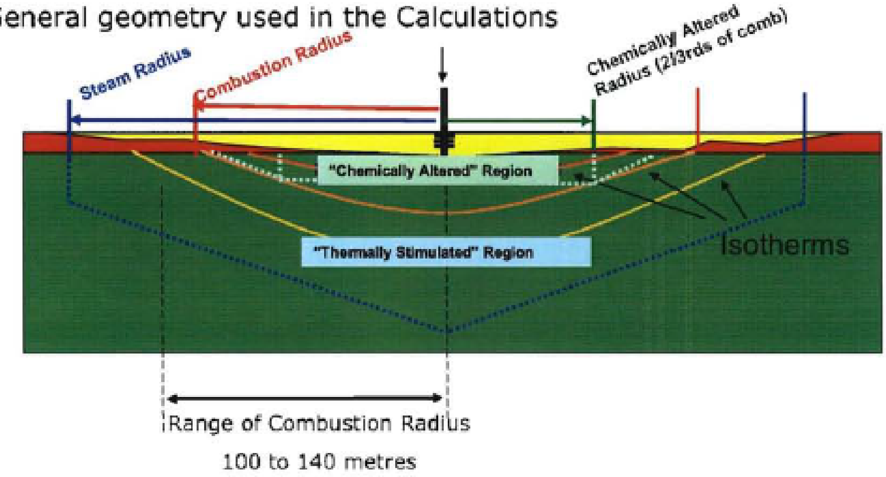


In answering some follow-up questions to Progress Report #3, Cenovus decided that the issue of the "impact on the bitumen" should actually be split between the chemically altered bitumen (identified through the presence of temperature, coke and oxygen) and the thermally stimulated bitumen (that can be seen at different temperature levels "above 60 deg C"). Cenovus selected the 60 deg C thermal stimulation level since the Wabiskaw bitumen should be 600 cp at this temperature allowing some mobility to the reservoir fluids. Appendix D has a section showing the bitumen impacted to date and the geometry of the bitumen influence in March 2012 and 2015. Utilizing the geometry expected from both the 3D numerical simulations and the burned volume calculations, the current EnCAID is expected to have about 6,400 m3 of chemically altered bitumen with an additional 71,000 m3 of bitumen thermally stimulated above 60 deg C. By the end of the EnCAID displacement of the east side of the Wabiskaw K-3 Pool in March 2015, 11,700 m3 of chemically altered bitumen would be created with a burn front radius of 140 meters with 131,000 m3 of thermally stimulated bitumen (Figure 5.1.10).

Figure 5.1.10 EnCaid Impact on Bitumen

EnCAID Impact - Heated Volume Diagram

General geometry used in the Calculations



Estimate of Front Position from Material Balance on Combustion Calculation

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Issue: Heat Effects in Bitumen

Calculations

- Current Day
  - Burned Radius ~= 103 meters
  - Chemically Altered Volume ~= 6,400 m^3 of oil
  - Thermally Stimulated Volume ~= 71,000 m^3 of oil
  - Total Affected Volume = Chemically + Thermally ~= 77,400 m^3 of oil
- March 2012 Approval (Forecast)
  - Burned Radius ~= 124 meters
  - Chemically Altered Volume ~= 9,200 m^3 of oil
  - Thermally Stimulated Volume ~= 102,000m^3 of oil
  - Total Affected Volume = Chemically + Thermally ~= 111,200 m^3 of oil
- East Side Gas Depletion to 2014/2015 (Forecast)
  - Burned Radius ~= 140 meters
  - Chemically Altered Volume ~= 11,700 m^3 of oil
  - Thermally Stimulated Volume ~= 131,000 m^3 of oil
  - Total Affected Volume = Chemically + Thermally ~= 142,700 m^3 of oil
- Original EnCAID Application identified 120,000 m^3 of bitumen to be affected based on all volumes that would be heated at all.

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5.1.4 Temperature Data

The 102/5-10 wellbore is equipped to measure 10 temperature points from above the Wabiskaw zone through the gas interval to 15 metres into the bitumen leg.

Figure 5.1.11 displays the thermocouple locations and temperatures with respect to the geological setting in the 102/05-10-073-06W4 observation well. Since the maximum preheat steam injection temperature was 280 deg C and field measurements have reported temperatures up to 400 deg C within the gas section of the formation, successful heat generation from in-situ combustion fueled by the oil in the gas zone has been demonstrated.

The temperature profiles appear to be showing an initial combustion movement in the top of the gas zone. The peak temperature response time in the gas zone at the 102/05-10-073-06W4 observation well occurred on December 15th, 2006 at about 200 to 210 days. The thermocouple in the top of gas zone showed an unexpected second peak temperature (around 320 deg C) about 1 year after the initial 396 deg C peak. A subsequent response was observed in the bottom of the gas zone where temperatures have risen as high as 275 deg C, dropped to 216 deg C, increased to a second peak of 331 deg C and now retreated to a temperature level below 200 deg C. At this time it is suspected that the combustion front has moved past both the top of gas zone thermocouple that is around 160 deg C and the bottom of gas thermocouple at 180 deg C at this observation location 30 meters from the injector. The thermocouple point at 1 meter into the bitumen is now being monitored to see what combustion responses might be taking place in this first meter of bitumen.

At the time of the first peak temperature in the gas zone (December 2006), thermal trends at the 102/05-10 well correspondingly showed a temperature response between 4 and 7 meters into the bitumen. This event correlated well with the simulation at 100 days at the injector location which showed increased temperatures up to 5 to 6 meters into the bitumen leg between the injector and the observation well. Currently, as shown in Figure 5.1.12, EnCAID is reporting a temperature response of over 60 deg C into the bitumen leg to a depth around 15 meters at a distance of 30 meters from the injection well.

Figure 5.1.11 102/05-10-073-06W4 Observation Well Temperature Trend

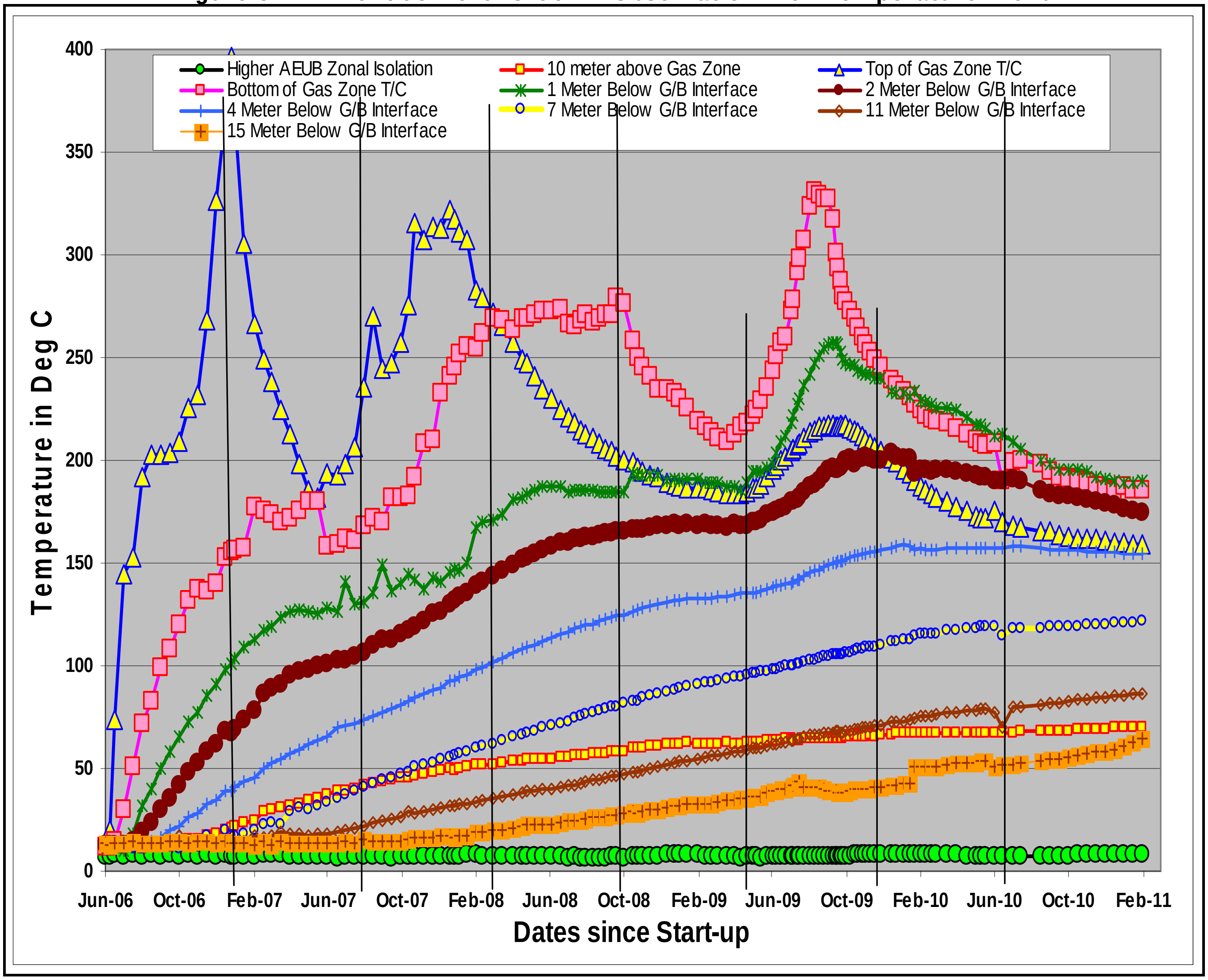


Figure 5.1.12 Observation Well Temperature History

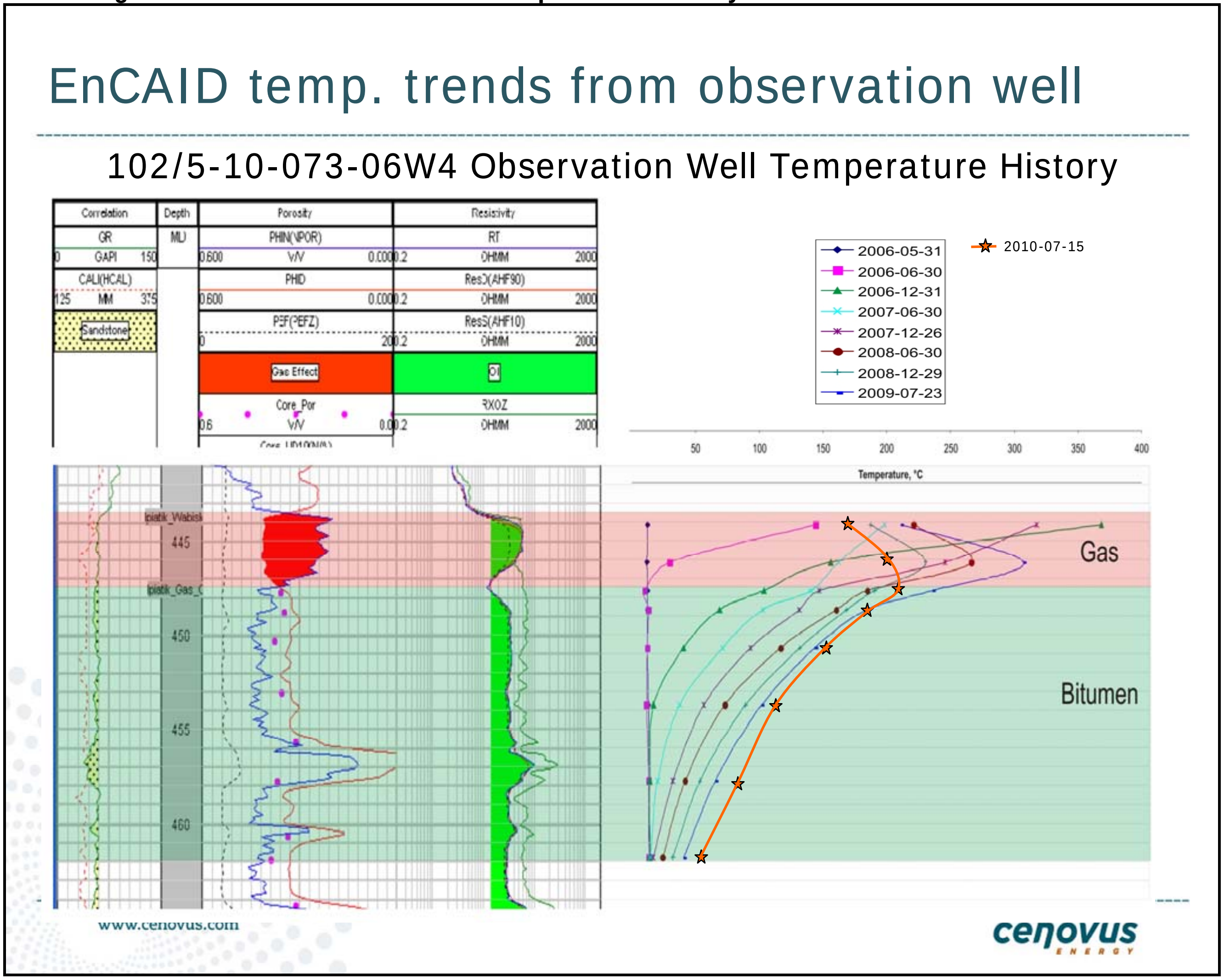


Figure 5.1.13 shows a snapshot of the thermocouple data being recorded in 102/05-10-073-06W4 & 100/06-10-073-06W4 on February 4, 2011.

Figure 5.1.13 EnCAID Thermo Snapshot – Feb 4, 2011

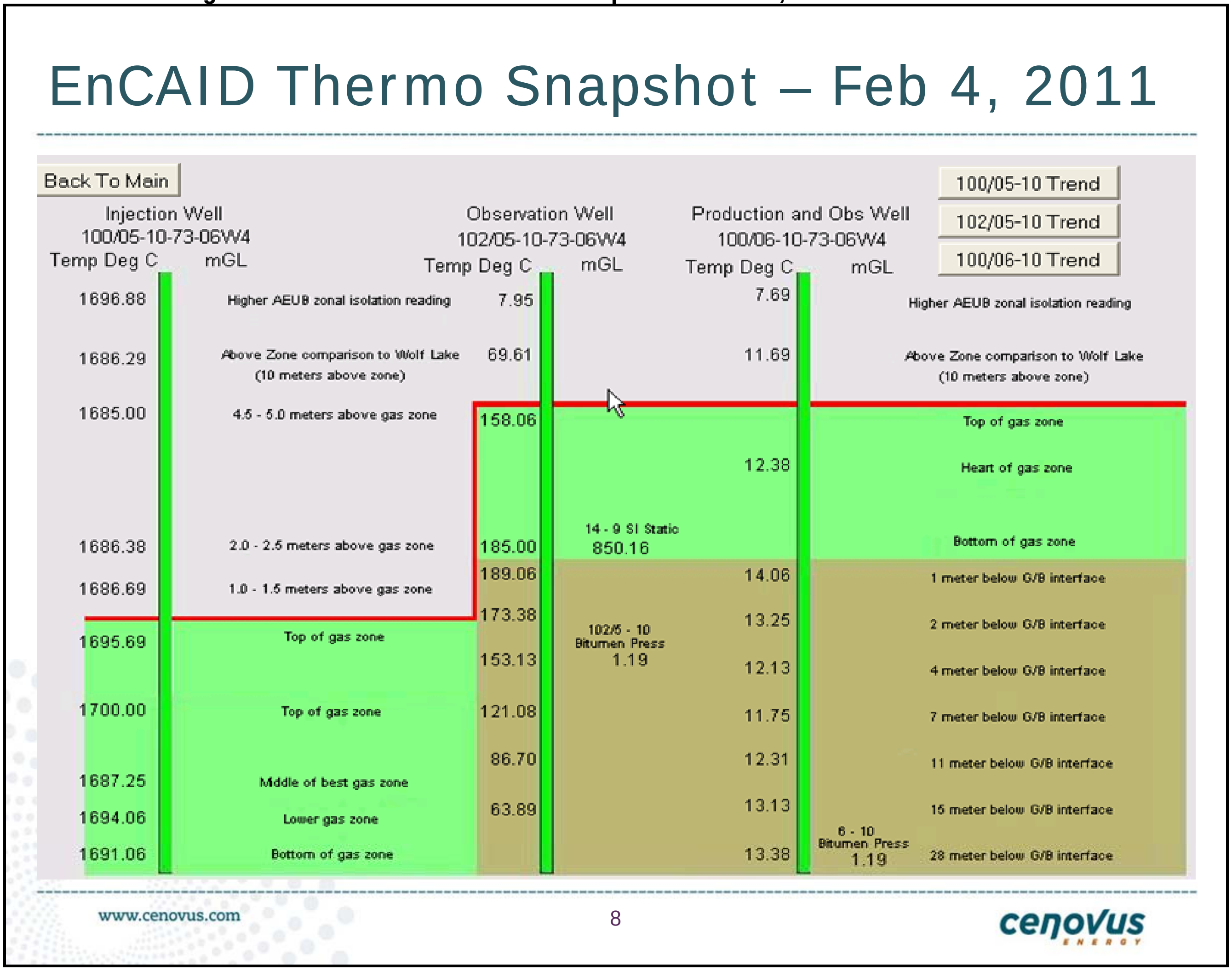


Figure 5.1.14 shows the historical temperatures at the 100/05-10-073-06W4. Temperatures since project startup June 2006 have continued to trend in the range of 15 deg C to 30 deg C with a relationship to inlet air temperature & therefore compressor discharge temperature. The thermocouples were removed from 100/05-10 in December 2010.

Figure 5.1.14 100/05-10-073-06W4 Injection Well Temperature Trend

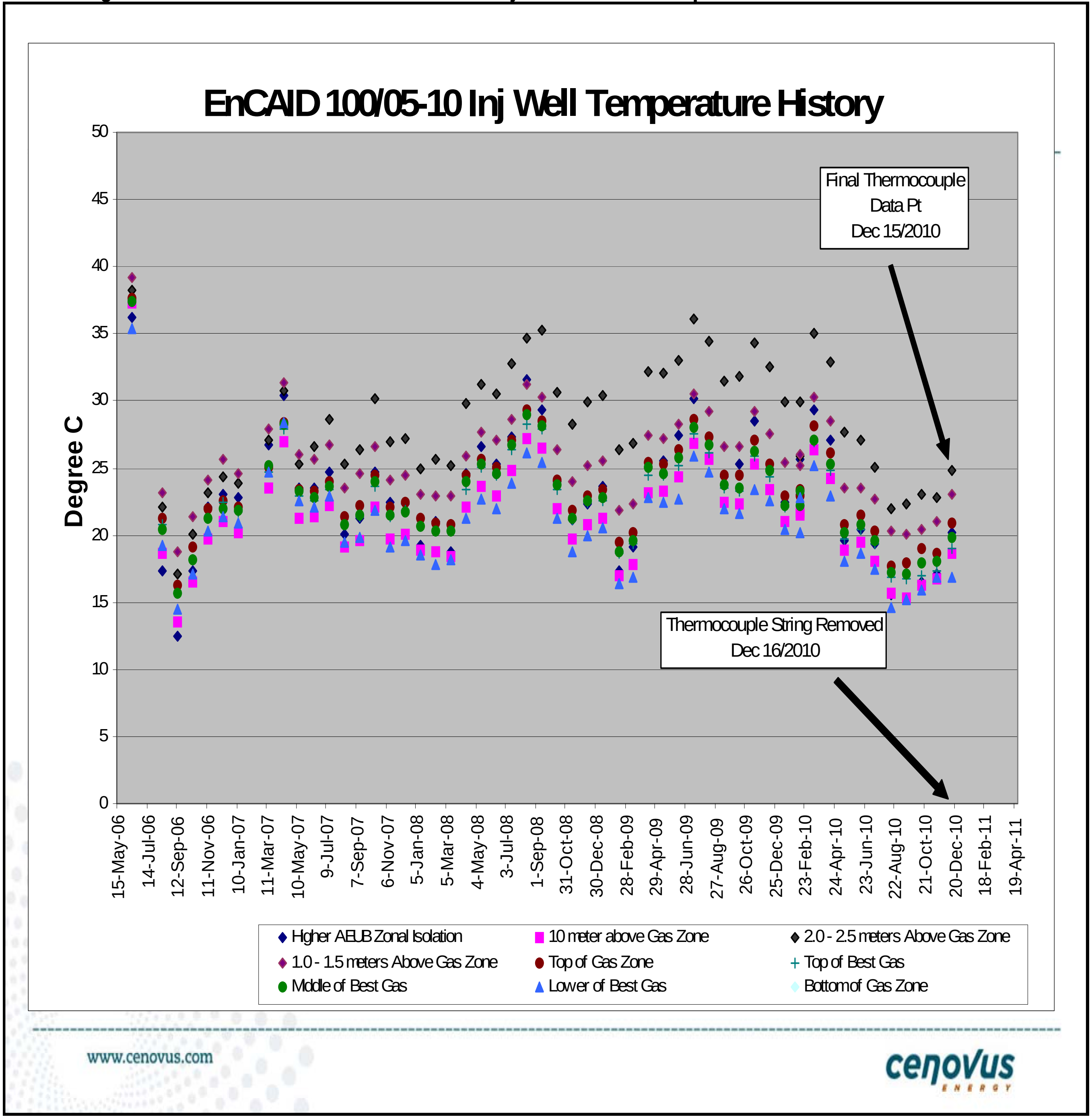
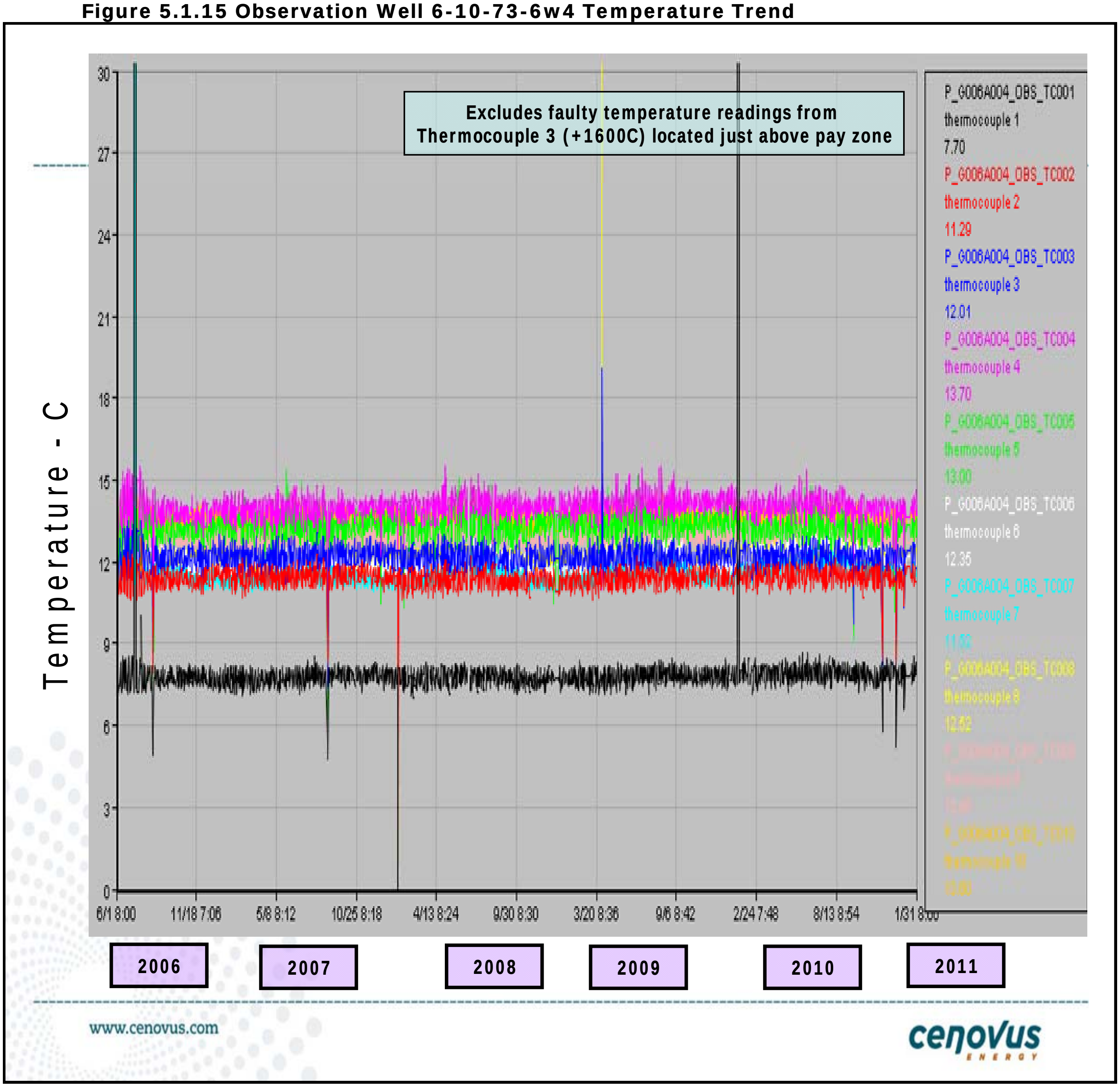


Figure 5.1.15 shows the historical temperatures at the 100/06-10-073-06W4 observation well. No temperature response due to combustion has been observed at this well since project startup on June 2006.

Figure 5.1.15 Observation Well 6-10-73-6w4 Temperature Trend

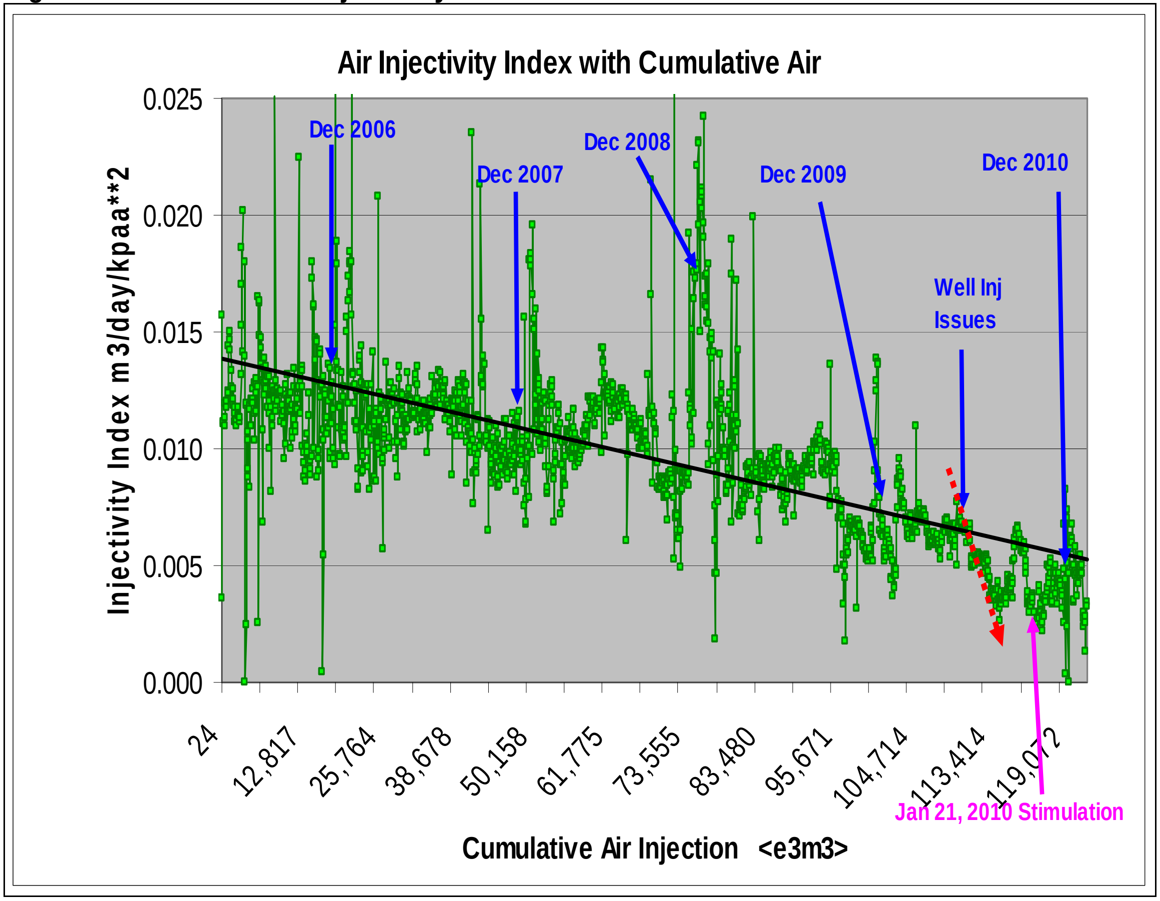


5.1.5 Air Injection and Well Pressure Response

Cenovus has achieved almost continuous injection of air over the time period since the June 2, 2006 ignition. Weatherford nitrogen membrane and underbalanced drilling air compressors were used for the initial blendup (15 days) and were available to substitute for the Cenovus system when both compressors had rod problems in mid July 2006 (19 days) resulting in only one day of non-injection in July 2006. The only other interruptions to air injection have been a one day pressure falloff test during the process of acquiring Wabiskaw static gradients in mid December 2006 and a sporadic interruption in air flow when we tried low air rates in January 2009 to keep our voidage balance in order. The only interruptions to air injection during the 2010 reporting period were December 19-21 and December 26-27 when pressure tests were undertaken. The average air injection rate since startup has been 2.52 MMSCFD, while for the period January 2010 to January 2011 the average injection rate was 1.69 MMSCFD which has resulted in a cumulative air injection just over 4.3 BCF. Figure 4.1.8 displays the daily air injection rate and injection wellhead pressure history from the inception of the EnCAID process.

Cenovus experienced an injectivity reduction in Fall 2009 from the initial injection rates of 3.0 to 3.2 MMSCFD down to around 2 MMSCFD at the maximum compressor discharge pressures around 3400 kPag. A slow injectivity loss is expected with both the reservoir pressure increasing (meaning a lower differential pressure to inject) and a slight banking of oil saturation in the gas cap (as seen from simulations) that suggest there is more resistance within the injection zone. These effects explain the gradual reduction in injectivity index from 0.013 $m3/day/kPa^2$ to 0.008 $m3/day/kPa^2$ (Figure 5.1.16). A larger concern was the sudden drop in air injection rate as low as 0.7 MMSCFD in Fall 2009 which is believed to be due to compressor oil carryover past the cyclonic separator and downhole into the 100/5-10 injection well. This carryover led to the injectivity index dropping as low as 0.002 $m3/day/kPa^2$ and led to the January 21st, 2010 stimulation treatment with small amounts of Champion DT-146 (a solvent and surfactant dispersant mix) displaced by nitrogen. The executed program led to a short term recovery of the injectivity index back to the long term trend for approximately five months, then the injectivity problems resumed for the balance of the 2010 reporting period. Overall, the EnCAID air injectivity index since startup has averaged 0.009 $m3/day/kPa^2$, with air injectivity index of 0.005 $m3/day/kPa^2$ for the reporting period. The reduction in the air injection index Cenovus feels is directly attributable to the compressor oil carryover issue which has created wellbore skin effects in the air injection well.

Figure 5.1.16 EnCAID Injectivity Index Trend



In order for Cenovus to better understand the issue of compressor oil carry over and its impact on the injection rate, Cenovus wanted to perform pressure fall off tests on the injector. However in order to perform the fall tests it was necessary to recover the thermocouple string from the injector wellbore. After having reviewed the historical downhole temperature data for the injection well, and concluding that the well had seen no significant changes since project startup in June 2006, Cenovus requested a wavier on continuous monitoring of the downhole temperatures on the injection well. Cenovus received permission under approval 10440H to not reinstall the thermocouple string in the air injection well on December 12th, 2010 and removed the thermocouple string on December 16th, 2010. One key benefit of the removal was that Cenovus was able to gather downhole samples of the compressor oil that had carried over. Cenovus took these samples and had them analyzed in order to determine an appropriate chemical treatment to apply in a workover in order to deal with the reservoir plugging caused by the compressor oil.

Cenovus performed two pressure Fall-off tests on December 12-21 and again on December 26-27, recovering the downhole pressure gauges on January 12, 2011. Cenovus undertook a basic transient well analysis in order to determine the magnitude of near-wellbore damage (skin) damage the injector was experiencing. The results based on analysis utilizing Fekete Well Test software indicate a skin factor of approximately +85, see Figures 5.1.17 & 5.1.18. In order to assess the level of near-wellbore damage (skin), the fall-off test data was analyzed using the Fekete F.A.S.T. WellTest application. The Pressure Transient analytical methods that WellTest is based on assume constant temperature in the reservoir, and does not account for the combustion products present, fire front, and potential “oil bank” near the combustion front. However, the method should be appropriate for analysis of near-wellbore damage as these variables should have little influence in this region.

Figure 5.1.17 100/5-10-73-6 W4 Injection Well Fall-off Test #1

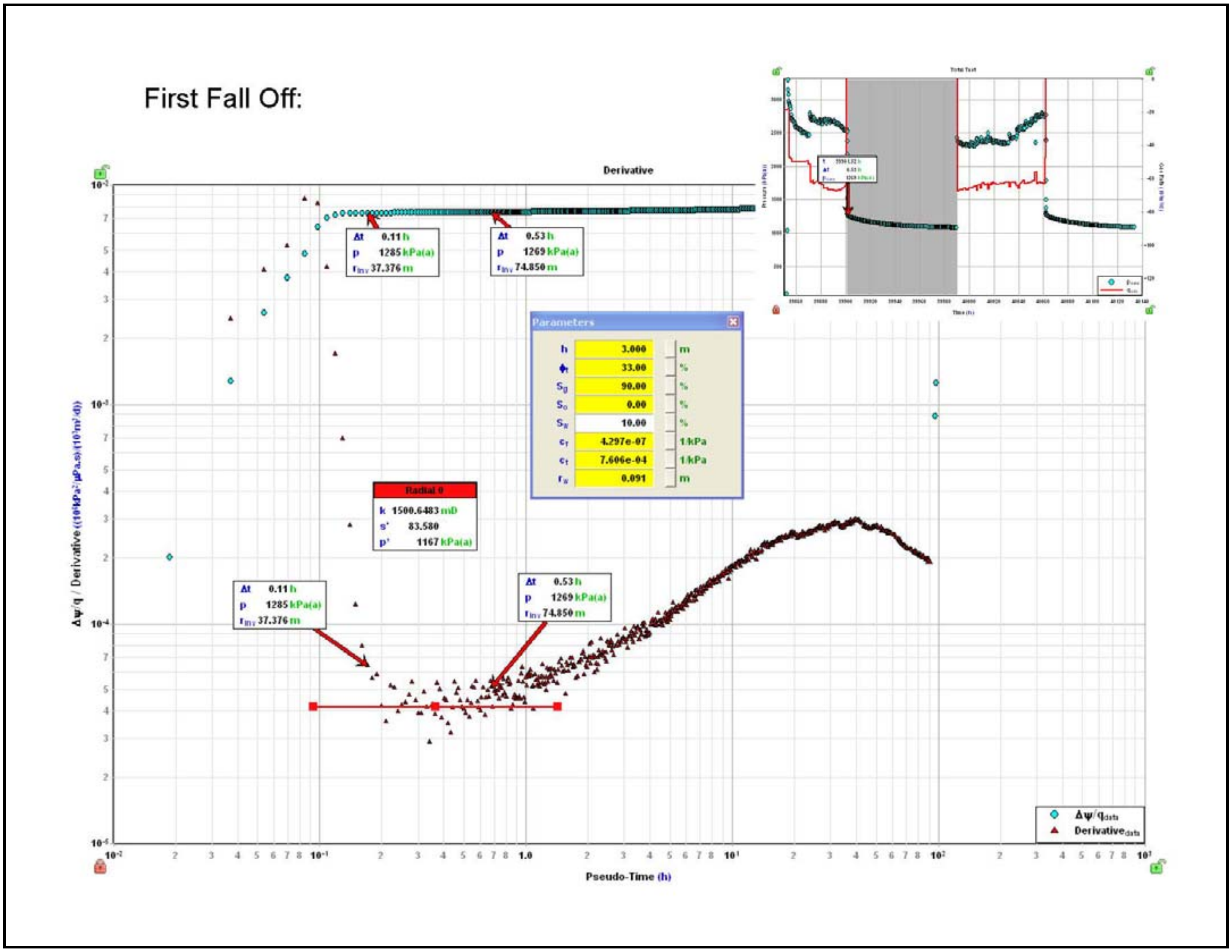
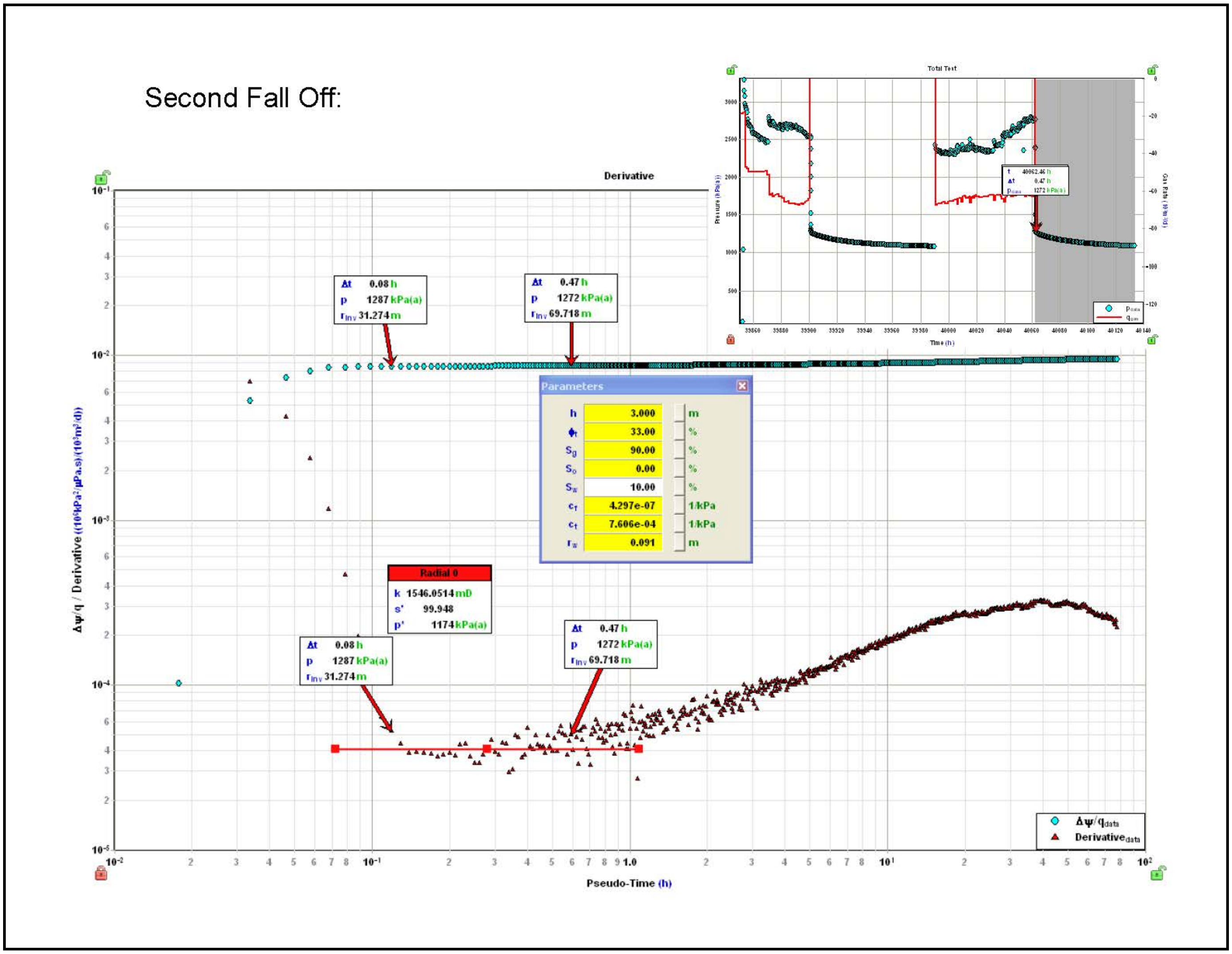


Figure 5.1.18 100/5-10-73-6 W4 Injection Well Fall-off Test #2



6. Pilot Economics Summary

Encaid Summary:

All values in $
All volumes in '000 m3

	2006	2007	2008	2009	2010	2011		PTD	Calculation
Revenue ($)[1]		6,208,810	3,308,301	1,476,304	1,197,135	840,593	**$**	**13,031,143**	**a**
Revenue (vol)[2]		27,601	15,857	15,362	12,335	8,140		**79,295**	
Royalty Cost		1,244,719	707,388	97,373	24,228	134,851	**$**	**2,208,559**	**b**
Operating Cost	168,295	576,158	970,124	727,124	541,712	256,951	**$**	**3,240,364**	**c**
Capital Cost[3]	8,703,442	784,691	699,659	700,661	334,812	38,239	**$**	**11,261,504**	**d**
	8,871,736	2,605,569	2,377,172	1,525,158	900,751	430,041	**$**	**16,710,427**	
IETP Royalty Adjustment Claim	1,000,000	1,000,000	1,000,000	999,046	-	170,954	**$**	**4,170,000**	**e**
Cash Flow	(7,871,736)	4,603,241	1,931,129	950,192	296,384	581,506	**$**	**490,716**	**f = a - b - c - d + e**

Notes:

[1]Based on Net Revenue $ for Encaid operations activity period.

[1]Based on Net Revenue Volume ('000 m3) for Encaid operations activity period.

[3]Includes the cost of injectant per Annual IETP Filings.

7. Facilities

7.1 Major Capital Items

The major installations / modifications for the project were:

- Two 600 HP 5 Stage Reciprocating Air Compressors
- Conversion of the 100/5-10-73-6W4 well to air injection service including installing a thermocouple string
- Drilling, coring and instrumentation of the 102/5-10-73-6W4 observation well
- Conversion of the 6-10-73-6W4 well to observation with pressure and temperature monitoring
- Installation of gas chromatographs for continuous monitoring of produced gas compositions
- Segregation repair at 6-18-73-6W4
- 100/5-10-73-6W4 injection well solvent squeeze Feb 2010.
- Planned installation in 2011 of coalescing filters to curtail compressor oil carryover into the injection well
- Planned cleanout and solvent stimulation at the 100/5-10 injection well to wash the oxidized compressor lube oil out of the critical near wellbore region

7.2 Capacity Limitation, Operational Issues, and Equipment Integrity

The air compressors had sufficient capacity and minimal downtime over the reporting period. The compressors were fitted with inter stage lube oil recovery, but it was a design oversight that there was not oil recovery on the final stage. This caused extra expenses in working over the injection well and retrofitting with coalescing filters.

Thermocouple strings and pressure monitoring has worked reasonably well and provided good information as to the in-situ process.

The gas chromatographs have turned out to be somewhat problematic in the field requiring frequent recalibration. As compositional changes have occurred over periods of months to years, the monthly laboratory analyzed samples have provided good compositional information on a sufficiently timely basis and the gas chromatographs have turned out to be largely redundant.

The primary operational issues have been managing production rates to maintain sales spec gas at the plant and supplying the appropriate injected air volumes to maintain the required voidage ratios.

7.3 Process Flow Diagram and Site Layout

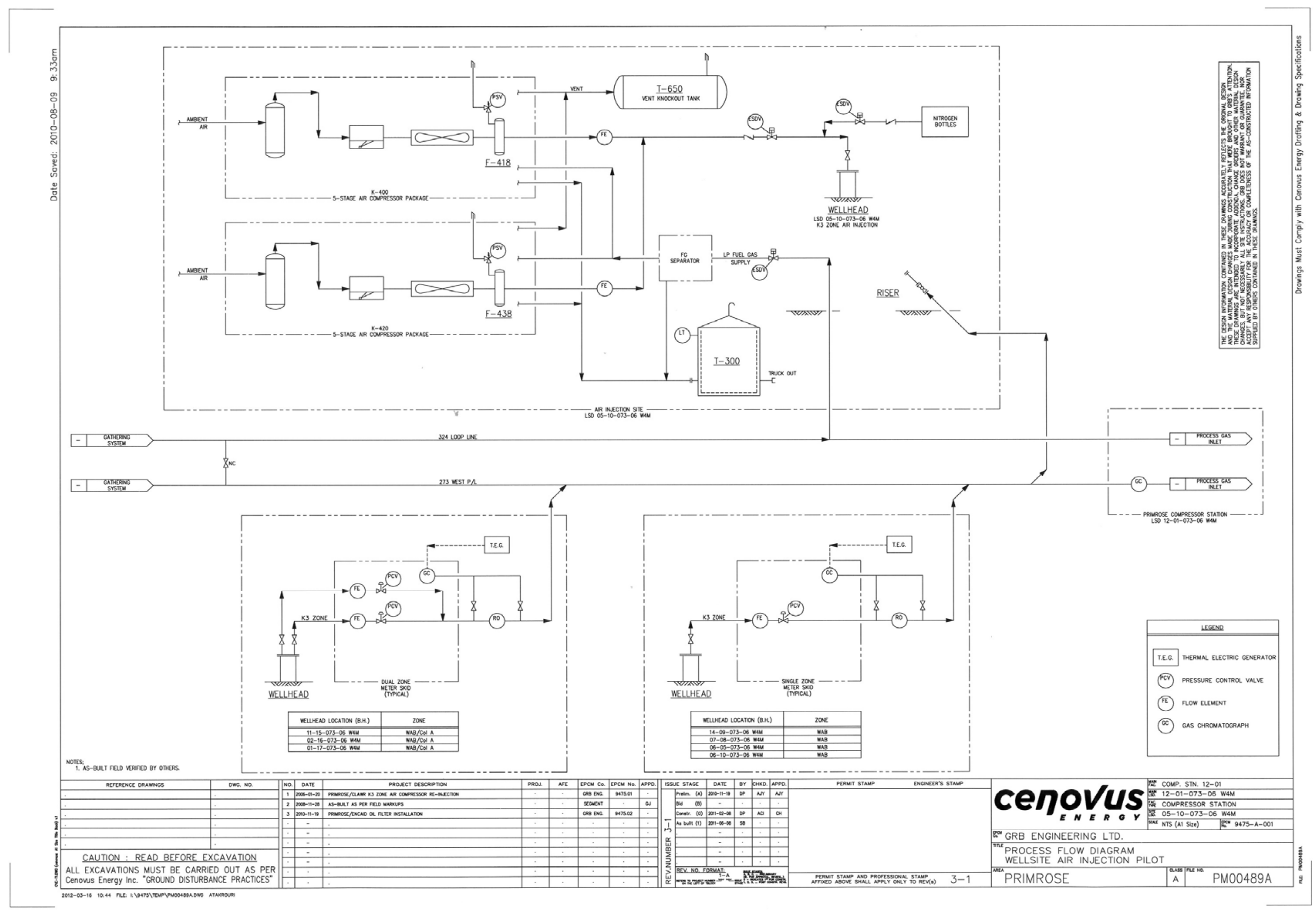
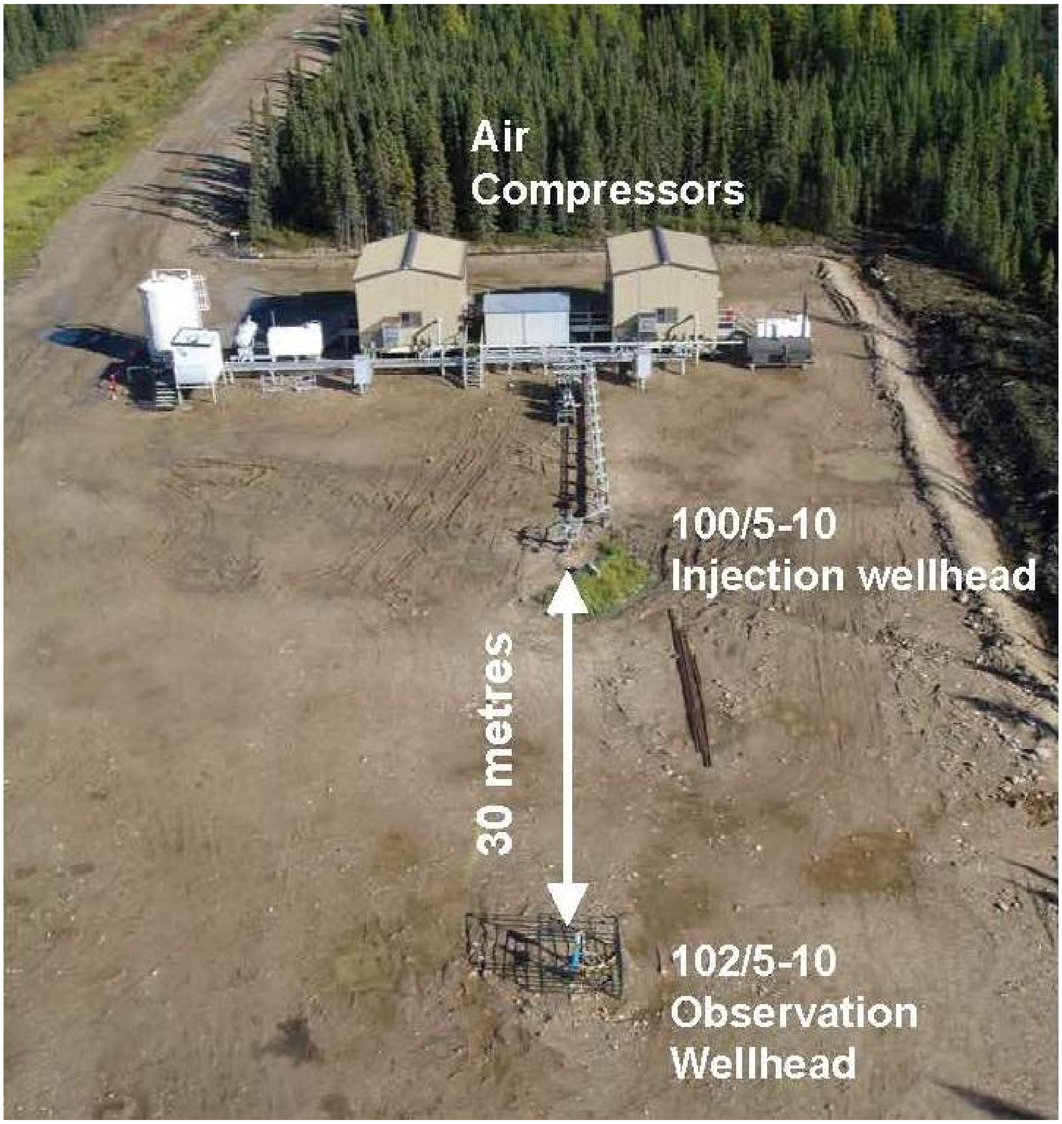


Figure 7.3.1 EnCAID Site Layout



8. Environment / Regulatory / Compliance

8.1 Summary of Project Regulatory Requirements and Compliance Status

8.1.1 Regulatory Approval

The initial EnCAID concept was developed & investigated through simulation work from April 2004 to the Fall of 2004. Following the Final GOB shut-in decision (Order 05-001), Cenovus submitted a Review & Variance (November 23rd, 2005) to allow the Wabiskaw wells involved in the EnCAID process to be restarted in conjunction with the process. The final Approval to produce gas was issued on January 4th, 2006 in combination with the formal process Approval 10440 on December 22nd, 2005

Approval 10440: Issued December 22nd, 2005, Initial Approval Terms

Injection:

- Injection pressure below 6000 kPag, Range 1600 – 4500kPag
- Guide 51 Approval received for 100/5-10-73-6W4 air injector
- Continuous monitoring of injector annulus showing 22 to 160 kPag

Gas Production:

- Gas production through seven allowed gas producers

Pressures & Temperatures:

- Continual subsurface bitumen & gas measurement through observation well 102/5-10-73-6W4. Bitumen at 102/5-10 but amended to surface gas pressure at 14-9 Hz or 6-5
- Semi-annual downhole pressure gradients at 4 shut-in pool wells plus annual surveys at 3 "out of pool" wells
- **Temperatures**
  - Mid-point of injection well, actual on-line collection of 10 temp points
  - 4 temperature points at 102/5-10 observation well, continually monitor 2 gas, 6 bitumen and 2 research points
  - Intermittent temperature surveys at 100/6-10 obs / prod well, continuous 10 temps and 1 piezo pressure

Gas Analysis:

- Full Gas Analysis following pressure gradient timing – greatly exceeded this sampling

Major Guidelines:

- Monthly Voidage Ratio must be 0.9 to 1.4 (amended) with minimum annual of 1.0, maintaining top range of voidage
- Bottomhole stabilized pressure at any wells falls below 700 kPaa, production will be shut-in until it recovers, 6-18 segregation problem outside Wabiskaw K-3 Pool occurred in early 2009 resulting in high VRR
- Submission of "bi-annual" progress report
- Reporting of surface & downhole corrosion, no abnormal corrosion observed
- Three year from injection confidentiality, expires about May 1, 2009
- Original Approval expires on April 1, 2009, which has been extended to March 31, 2012

Amendments

10440A: Issued April 3rd, 2006, Swap pressure monitoring

- required due to access problems with bitumen blocking or crimped coil tubing string on the 5-14-73-7W4 wellbore, outside the K-3 pool
- approval allowed Cenovus to utilize another offsetting well 100/10-36-72-7w4 for Wabiskaw zone monitoring.

10440B: Issued August 10th, 2006, Exchange continuous gas pressure monitoring point

- required due to failure of gas pressure piezometer at observation well 102/5-10-73-6W4
- exchanged for continuous surface pressure measurement at 6-5-73-6W4 as long as within 150 kPa of bottomhole pressure

10440C: Issued June 28th, 2007, Exchange Shut-in Gas Pressure Monitoring wells & Monthly Ratio change

- shift surface shut-in gas pressure monitoring duties from 6-5-73-6W4 to 14-9-73-6W4 Hz well once it was shut-in for high nitrogen
- approval to restart shut-in producer 6-5-73-6W4 when 14-9 Hz shut-in
- elimination of requirement to shut-in producers when a nitrogen level of 20% is reached
- Intermittently, the 14-9 Hz well can be flowed for 2 days in order to get a good gas sample then shut-in again
- Allowed to increase upper limit of monthly inj:prod voidage ratio from 1.1 to 1.25

10440D: Issued January 24th, 2008, Increase Monthly Voidage Ratio Limit

- Further increased monthly inj to prod ratio upper limit to 1.40 to better utilize air compression

10440E / 10440F: Issued April 2nd, 2009 / September 24th, 2009, Amendment for Time Extension

- Primary purpose, extension of approval expiry from April 1st, 2009 to March 31st, 2012 to allow additional experimental data to be acquired.
- Approved further increase in upper limit of monthly ratio from 1.4 up to 2.0
- Approved cumulative voidage ratio target up from 1.1 to 1.6 to allow utilization of air injection capacity
- Approved request for reduction of semi-annual pressure surveys within pool to annual
- Approved request to reduce semi-annual progress reporting frequency to annually

10440G / H: Issued January 19th, 2010 / December 12th, 2010, Amendment for Time Extension

- Transfer scheme from EnCana Corporation to Cenovus Energy Inc.
- Project changed from Experimental scheme to Enhanced Recovery Scheme
- Rescinded temperature monitoring requirements in injection well

8.1.2 Regulatory Compliance

Self-Disclosure of Pressure Non-Compliance & Excessive Monthly Voidage Ratio

Cenovus sent the ERCB a self-disclosure letter on January 20th, 2009 when recent static gradient analysis identified that a well inside the Kirby Upper Mannville I pool but outside the EnCAID Wabiskaw K-3 pool had a pressure decline to 641kPaa. As per ERCB approval 10440D, Clause 16 stated that production shall be shut-in if ANY bottomhole stabilized sandface pressure drops below 700 kPaa. This letter identified that the reservoir pressure at the well 6-18-73-6w4 dropped below this limit and EnCana shut in the EnCAID gas production as of January 19th, 2009. Gas production was eventually returned to previous levels on February 25th, 2009 after the 6-18 segregation was repaired and the Wabiskaw formation pressure was confirmed to be 940 kPaa (well above the ERCB minimum pressure level of 700 kPaa)

As a result of the above discussed gas production shut-in, on January 26th, 2009, Cenovus had to self-disclose the violation of Clause 15 of Approval 10440D in regards to maintaining a monthly injection to production ratio between 0.9 and 1.40. Despite reducing the air injection rate from 3+MMSCFD to 2.0 MMSCFD then 1.4 MMSCFD, Cenovus reached a monthly voidage ratio near 1.675 for January 2009 and 10.339 in February 2009 due to the gas production dropping to zero for a large period of each month. It is critical to maintain an air rate to facilitate the combustion process, so Cenovus was unable to drop the rate lower than about 1.6 MMSCFD and keep the air compressors running steady. Following the 6-18 segregation repair, the operation of the air injection and gas production was able to return to normal levels and a compliant monthly VRR in the 1.1 to 1.6 range was achieved for the remainder of 2009.

Gas Migration & Surface Casing Vent Flow Work

Background Samples:

- Taken in 2005 at the suggestion of Don Hennessey at the ERCB
- No development at EnCAID site
- Existing tied-in gas leases at 14-9, 11-15, 6-10, 5-10 and standing well 4-14

October 2006:

- No SCVF observed on any wells
- LEL disappeared when went to “methane elimination mode” which is standard practice for these tests
- Natural methane readings were observed in some of the “control” sites away from the wells.

June 2007:

- Additional testing in response to April 2007 letter to Joanne Petryk
- First time attempted to collect “zero pressure” gas samples at control and test points on 5-10, 6-10 & 11-15.
- LEL detection in “Full Gas Detection Mode” disappeared in “Methane Elimination Mode” suggesting “swamp gas”
- Test company noted that clay cap over most of the sites could be trapping methane from organic peat decomposition

October 2007:

- Similar results

September 2008:

- Extra gas migration testing work added to annual work.

- Performed standard gas migration testing plus monitored additional “control” points off site.
- Collected low pressure gas samples for analysis at 5-10 & 11-15. Most tests confirmed “biogenic” gas but one sample at 11-15 was possibly from the Mannville around 400mKB (Dr. Karlis Muehlenbachs’ work at U of A)
- Added additional sampling points (8 per lease) under the clay cap on 5-10, 6-10 & 11-15 to better define trapping effects.

October 2009:

- Annual detailed gas migration check
- SDS concluded again that in their opinion it is a biogenic gas / swamp gas problem. Maxxam Gas sample had “insufficient hydrocarbon” to send for carbon isotope analysis. Of note, 5-10 & 6-10 control samples had more methane than the test samples.
- Single sample above 100% LEL came from a wet, sloppy, drilling mud type of soil west of well center. Fewer points indicated a “non-zero” LEL in 2009 and north high samples from 2008 are gone.
- Areas on lease with higher LEL moving around, not in same location as 2008.

October 2010:

- 2010 LEL readings less than 2009 readings, no samples taken.
- SDS opinion is it is a biogenic / swamp gas problem.

Corrosion Monitoring

Cenovus has completed its seventh removal and analysis of corrosion coupons in August 2010. Cenovus continues to monitor the trends in pitting and to see if it is due to changing gas composition or is just a function of analysis techniques. The three original tests and the August 2009 had not measured any pit depth whereas the November 2008 data showed minor pits on three of the six sample points. The August 2010 data has indicated that there now appears to be scattered severe pitting occurring, Cenovus is attempting to gain a better understanding of the source of this pitting in order to develop an appropriate solution to handle the pitting

Plan For Shut-down and Environmental Clean-up

Continuing to operate the project, but standard shutdown and cleanup for gas production facilities will apply.

9. Summary - Operating Plan

9.1 Actual Project Schedule

The initial proposed project schedule at the time of the mid 2005 applications and the actual project schedule are illustrated below. The major delay from an estimated mid January 2006 ignition was due to the timing of winter access, well work within a generally tight industry equipment market and delayed major equipment delivery partially due to late formal approvals. Acquiring a service rig for well work during a short winter access window proved to be difficult to schedule. General industry activity resulted in a significant delay by about 1 month in the installation of the major injection site air compression and monitoring equipment.

Figure 9.1.1 Proposed Project Schedule

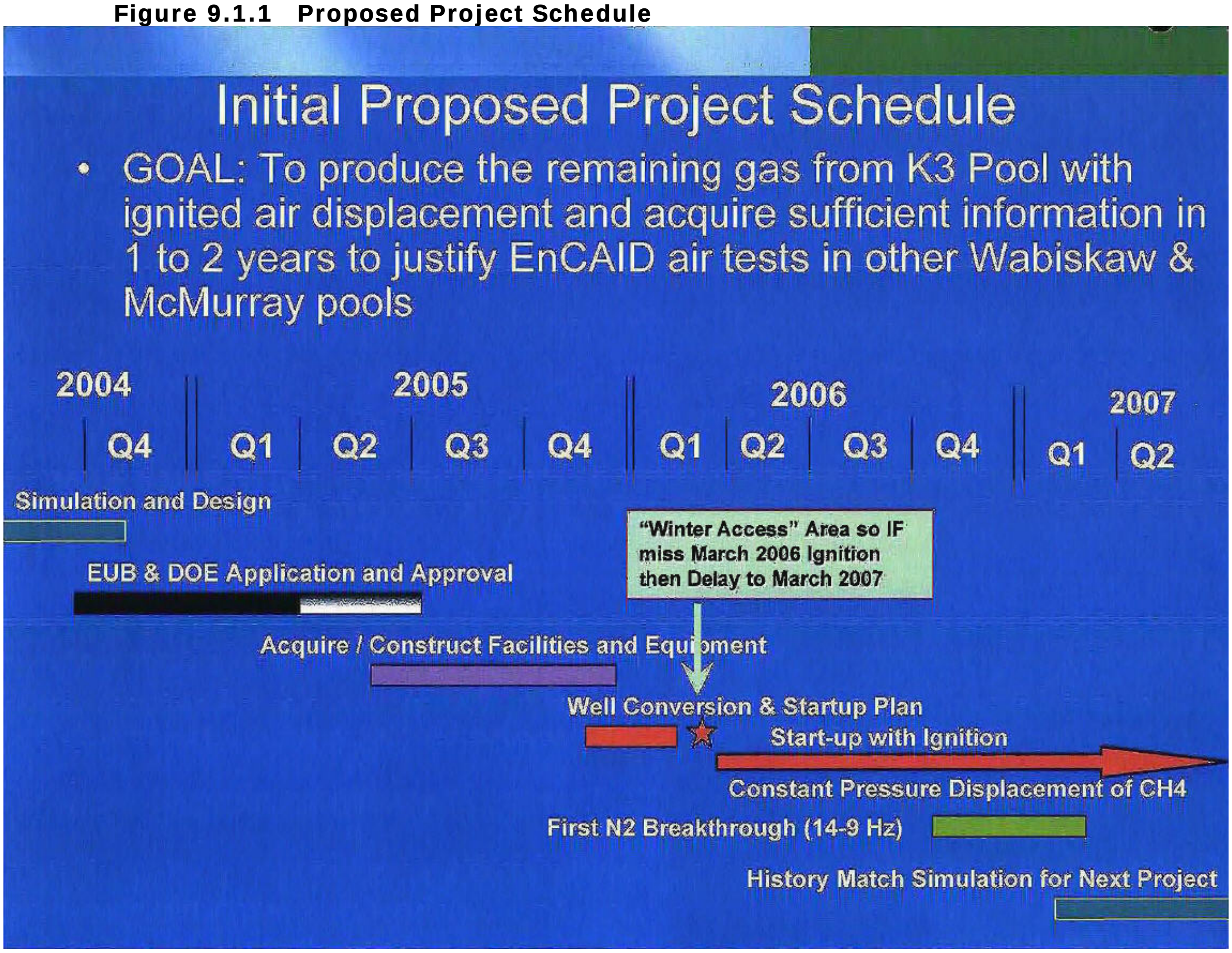
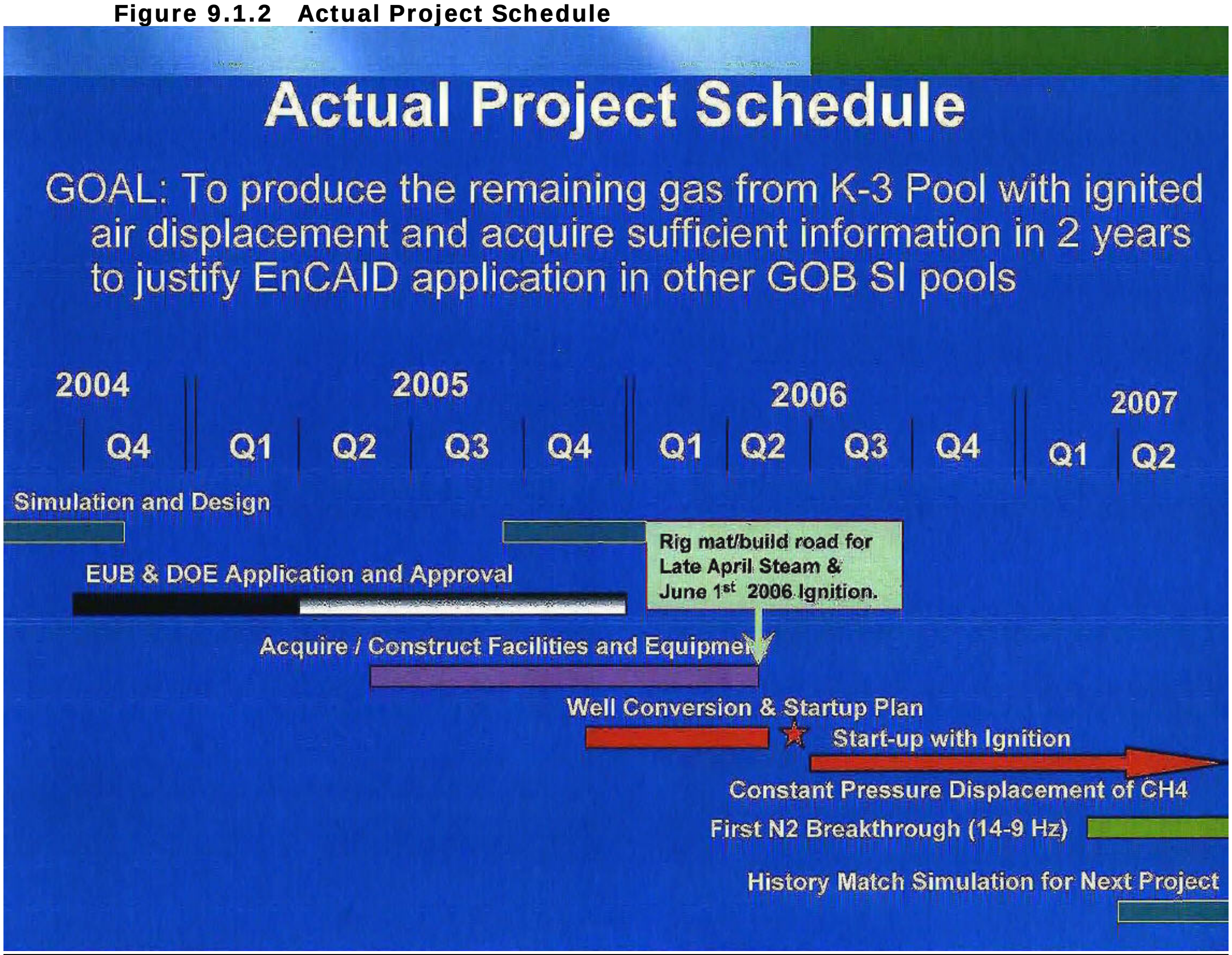


Figure 9.1.2 Actual Project Schedule



9.2 Changes in Pilot Operation, Planned vs Actual

Listed below are the main design variations from the original IETP & AEUB Applications. These changes came about through a combination of engineering design enhancement, technical review of the process & simulation and regulatory approval requirements.

Timeline Delay from original mid January Ignition to May 31st, 2006: The original timeline on the March 2005 IETP Application & May 2005 AEUB Application described an intended ignition of EnCAID by mid January 2006. Due to the need to perform well work in a winter access only area, general industry equipment delays and the delay of the formal AEUB Approval to December 22nd, 2005 (due to Phase 3 GOB SI Hearings), the actual ignition sequence for EnCAID did not start until May 31st, 2006 with the addition of the volatile oil. Prior to this date, about 20+ days of steaming took place to preheat the formation

Addition of an Observation Well at 102/5-10-73-6W4M: During the AEUB Approval process, a minority bitumen owner, Petro-Canada (Suncor), disagreed with Cenovus's contention that there would be minimal effects on the underlying bitumen resource. To address this concern, Petro-Canada & Cenovus drilled a 50/50 observation well at 102/5-10-73-6W4 which is 30 meters to the west of the 100/5-10-73-6W4 injection well. The wellbore was equipped to measure 10 temperature points from above the Wabiskaw zone through the gas interval to 15 meters into the bitumen leg while also capturing 3 pressure points with piezometers from above the zone, in the gas & in the bitumen.

Alteration of Injector Design for Temperature Measurement: As a follow-up to Petro-Canada's question on the combustion process effects on the bitumen, Cenovus decided to install a thermocouple string in the injection well to "mirror" the depths on the observation well from above the Wabiskaw zone to 15 meters into the bitumen. In order to eliminate any concerns on having any bitumen or ignitable products pooling in the injection well and causing a safety problem, the thermocouple string was cemented in place over the bitumen interval with only the gas perforations open to flow in the well. Subsequently, a mechanical problem with packer seals during the initial steaming phase caused a "catastrophic" failure of this thermocouple string over the bitumen zone. To address this loss, the remaining thermocouple string was salvaged and redesigned to supply temperatures above and across the Wabiskaw Gas zone. This injector thermocouple string did not observe any high temperatures at ignition above the existing steam temperatures and is now showing bottomhole air injection temperatures between 20 to 25 deg C.

Conversion of 6-10-73-6W4 Colony Producer into a Wabiskaw Gas & Bitumen Observation & Production Well: Again, with the AEUB's questions on the combustion process effects on the bitumen, Cenovus decided to abandon the 6-10-73-6W4 Colony zone and convert this well, that is 460 meters from the 5-10 injector, into a Wabiskaw Gas producer and Wabiskaw Bitumen Pressure & Temperature observation well. The conversion of this well as an eastern boundary of the pool producer was approved in the AEUB Project Approval 10440. Upon completion of the wellbore & after attempting two perforating runs, it appears that the well is barely in contact with the Wabiskaw pool and will not flow against a low line pressure of about 100 kPag.

Refinement of the Start-Up Strategy to Encompass Steaming, Volatile Oil Addition, N2 Injection & Air Injection: The original IETP & AEUB Applications described the concept of burning the 20 to 30% residual oil saturation in the Wabiskaw Gas zone to strip out oxygen and allow the combustion gases to displace formation gas at a 1.1 In: 1.0 Out ratio however it didn't really supply details on the start-up mechanics. The eventual plan arrived at for the EnCAID Project was to inject steam at about 100 m3 CWE/D (Cold Water Equivalent) with 3% KCl for compatibility for about 3 weeks to 1 month to bring up the formation temperature to 150+ deg C and also displace any formation oil away from the injection wellbore. The second step was to add an 11.9 m3 slug of a specific volatile oil mixture (Raw Linseed Oil blend designed through testing at the University of Calgary) then displace it out of the wellbore area with 1 day of steam injection & 1 day of 95% Nitrogen injection. The Ignition sequence was then safely completed with introduction of continuous air injection to form the ongoing displacement medium.

Downsize of Reciprocating Compression to 3.8 MMSCFD from 5 MMSCFD: The original IETP and AEUB Applications planned to deliver 5.0 MMSCFD up to 500 psig (3,500 kPag) of air from 2 reciprocating compressors (740 HP on 4 stages). The eventual design involved two 5 stage 600 HP reciprocating compressors to deliver the 3.8 MMSCFD (107 e3m3/day). Alterations occurred in the design in an attempt to match a more conventional compressor frame design to achieve reasonable delivery times since the initial compressor size looked like a 48 week delivery.

N2 Positive Flow System to Replace Water Kill System: Many of the original documents contemplated having a "water kill" system to avoid "burnback" on the injector and to quench temperatures if it was detected that the combustion front was coming back to the injection wellbore. Following design investigations by the third party engineering firm, it was decided that the technical challenges of delivering a sufficient volume of water to quench and the concern about pressures from steam flashing eliminated the water kill system idea. In place of the water kill, a nitrogen positive flow system was installed with two banks of ten nitrogen cylinders each. If failure of both of the air compressors is detected, the nitrogen system ESD is triggered allowing nitrogen from the first bank of gas cylinders to continue to provide a positive flow & pressure to the well in addition to creating a non-combustible environment within the wellbore.

On-line Analyzers for H2S & BTU in Addition to N2 & O2: The original documents identified the levels of Nitrogen & Oxygen as being critical control variables with Oxygen levels being key for safety and a general level of 20% Nitrogen used as a cut-off for shutting in production wells. Further technical discussions identified that it was worthwhile to measure the actual BTU level of the production gas and then combine this with the Nitrogen level to make a conscious decision on production well shut-in. In some cases, depending upon the Nitrogen levels of a combination of wellbores and the BTU levels, production from EnCAID gas wells could be stretched slightly beyond the 20% Nitrogen limit. In the final installation of the EnCAID facility, an available fuel gas line with dehydrated sales gas was tied-in so the onsite air compressors are not dependent upon the nitrogen content of the EnCAID production wells, potentially allowing a higher Nitrogen concentration threshold to be used in the shut-in decision. The H2S analyzers were added to the Primrose North Gas Plant inlet and several selected producers closest to the combustion front to do research to see if any sour gas is detected in the displaced gas due to the combustion process.

Core Analysis in the Gas & Bitumen Zone at the Observation Well 102/5-10-73-6W4: Once the AEUB Approval required the drilling of an observation well, Petro-Canada & Cenovus decided to recover a core sample across the entire gas & bitumen zone to perform current tests on the insitu properties. The initial Petrophysical data for the EnCAID pool for gas zone permeability & porosity as well as bitumen pay thickness was used in the simulation work but additional information on the fluid & rock properties was deemed to be helpful. Core & extracted fluid analysis took place in the first half of 2006 to better refine the zone properties and to verify assumptions in the simulation.

Refinement of the Petrophysics & 3D Reservoir Simulation for Combustion Frontal Position & Impact on the Bitumen Zone: With the introduction of the 102/5-10-73-6W4 Observation Well just 30 meters from the 100/5-10-73-6W4 EnCAID Injector, a requirement for a more detailed 3D simulation of the 500 meter region around the injector was needed to fully understand the observed data & timing for responses.

Extra Pressure Surveys for EnCAID: In the AEUB Approval 10440, the AEUB has requested a slightly more intense pressure survey schedule with semi annual measurements at wellbores within the EnCAID Wabiskaw pool combined with annual surveys on several wellbores outside of the EnCana identified K-3 Pool.

Background Corrosion & Gas Migration Work on Selected Wells: In conjunction with discussions with AEUB Bonnyville Field staff, some background wellbore corrosion monitoring and some gas migration work was committed to as a prudent plan. Five wellbores in the region of the 100/5-10 injector have been surveyed for any existing gas migration in order to determine any differences after the onset of combustion. Follow-up surveys did not detect any changes beyond observations of “swamp gas”, even with development of the sites with roads & facilities.

Improvement of 5-10-73-6W4 Lease Access with a Permanent Road: In assessing Cenovus’s needs for reliable access to the 5-10 air compressors and lease, the original plan for temporary rig mat access to the location was replaced with a $460,000 Road & Lease upgrade. This road & lease construction has been invaluable in allowing the successful execution of this EnCAID Project by allowing continued operations through break-up in a heavy muskeg area and providing support for continuous air injection through ongoing compression operations.

9.3 Optimization Strategies

Additional high heat value gas available to blend the high N2 produced gas will allow better ultimate recovery.

Wider VRR flexibility somewhere between the minimum to maintain combustion and not exceeding original pool pressure would make it easier to optimize air injection strategy.

For new applications, screw type compressors would allow more flexibility in air injection rates.

10. Interpretations and Conclusions

10.1 Assessment of the Overall Performance of the Pilot

10.1.1 Lessons learned

Cenovus continues to demonstrate a successful GOB Technical solution with the EnCAID project. The overall project has been shown to be successful through accomplishment of the following goals:

1) Successful Ignition of EnCAID Process: Temperatures at the observation well have suggested heat generation beyond the initial preheat steaming energy input. The combustion front is moving along well but slightly behind the original simulation timing. Knowledge and understanding of the process will continue to increase as the abundance of technical results are integrated into a detailed thermal simulator model.

2) Safe Operation of the EnCAID Process: The EnCAID process continues to safely produce formation gas from the Wabiskaw reservoir with continuous monitoring of the produced gas. Minimal problems have occurred during the injection of over 4.3 BCF of air and have been readily addressed by the field operations staff and facilities groups.

3) Efficient Delivery of Pressure Support: The Wabiskaw region where injection and production has taken place has increased in pressure by over 200 kPaa since the start of injection while the West shut-in side of the pool has increased by about 170 kPaa.

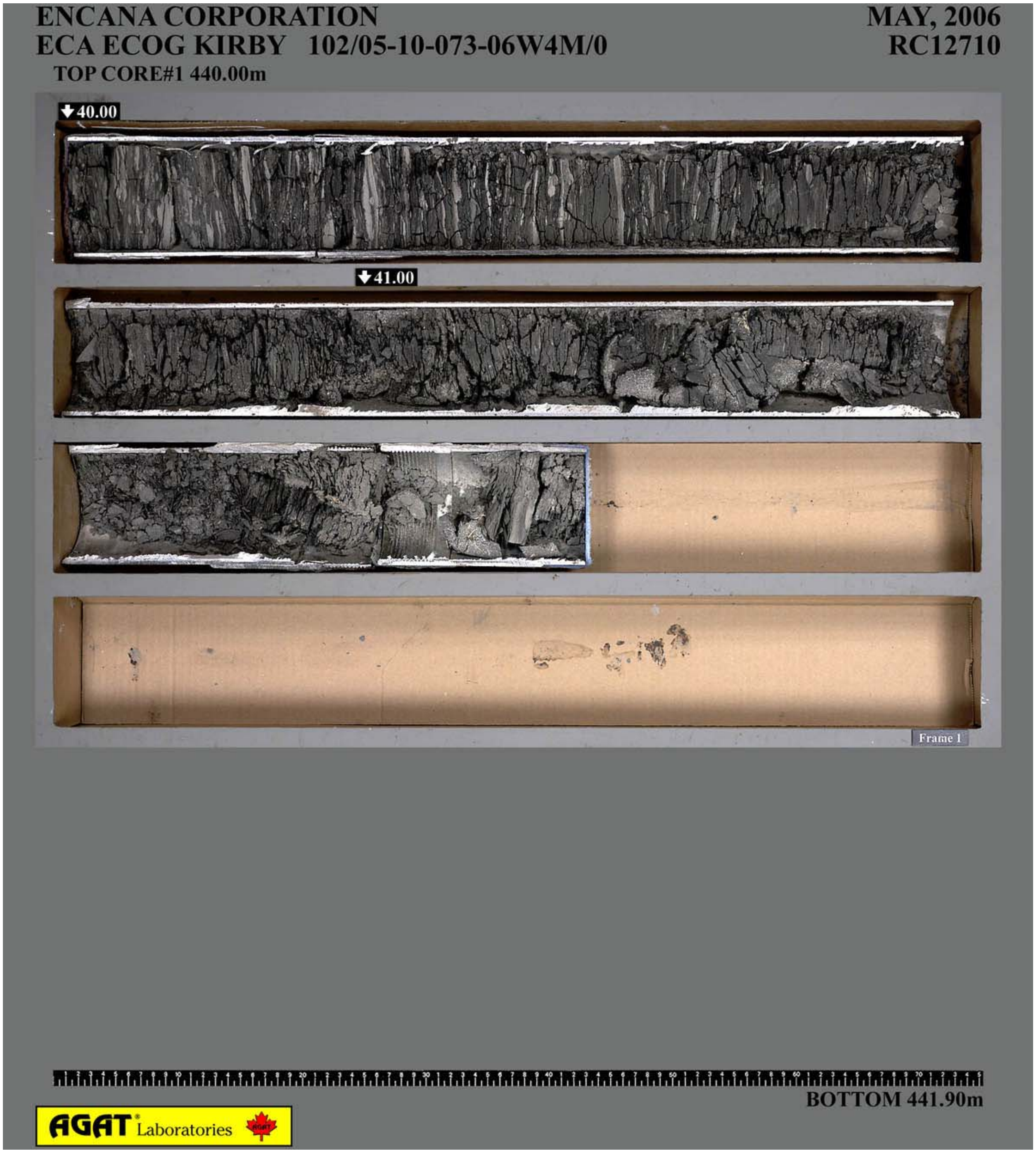
4) Steady and Continuous Air Injection: Average air injection rate for the project is approximately 45 e3m3/d (1.6 Mmcf/d) delivered with just 3.5 days of mechanical down time in over 1,700 days, the process performance ranks as top quartile performer. This strong operational work has resulted in the EnCAID Project solidly delivering the cumulative injection to production ratio of 1.22 : 1.00 and injecting over 121 e6m3 (4.3 BCF) of air. Concerns continue to exist with regard to the continuing low air injection rate that was experienced. It is anticipated that with the information gathered from the pressure fall off tests in December 2010 Cenovus will be able to gain better understanding of the compressor oil carryover issue and design a successful workover program to restore injectivity. In order to assess the level of near-wellbore damage (skin), the fall-off test data was analyzed which indicated a skin factor of approximately +85. The pressure transient analytical methods are based on assuming constant temperature in the reservoir, and does not account for the combustion products present, fire front, and potential “oil bank” near the combustion front. However, the method should be appropriate for analysis of near-wellbore damage as these variables should have little influence in this region.

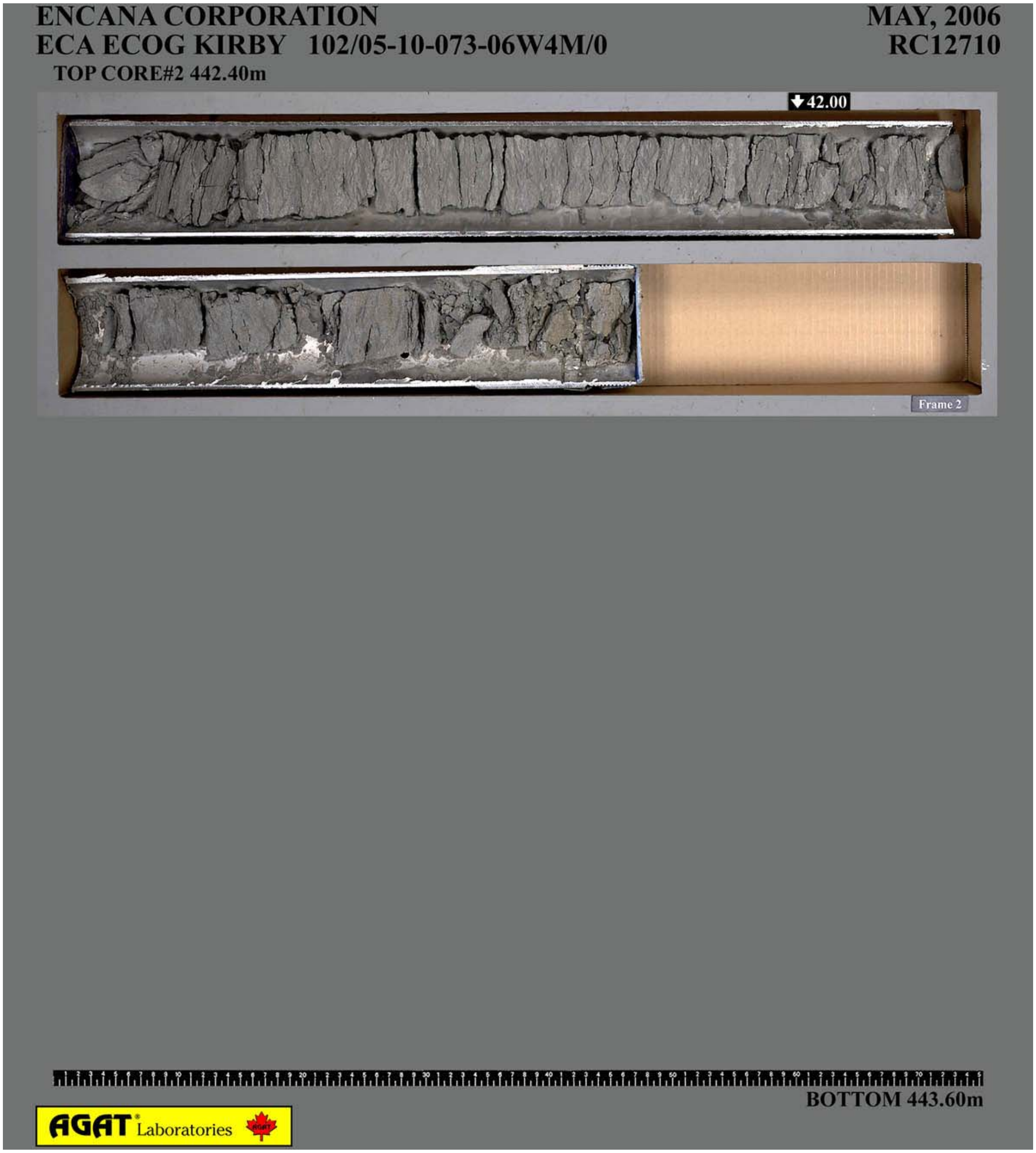
5) Proven value of temperature, pressure and gas analysis data: All of the information from the observation well, six producing wells and five shut-in wells have been integrated into the detailed three dimensional reservoir simulation model for improved interpretation of the process. Any opportunity to acquire additional field data on fluid flow is recognized as a very valuable exercise so Cenovus has gone to great lengths to keep wells producing even at high nitrogen levels (like well 14-9) and to acquire many more gas analysis samples than required in the Approval. Continuing the 14-9 sampling after the well was shut-in has allowed Cenovus to acquire extremely useful gas displacement information such as the delay in carbon dioxide response by about 9 to 12 months. During the reporting period we have only observed H_2S levels in the range of 0.5 to 3 ppm on the EnCAID producers with nitrogen response, but will continue to do intermittent trace sulphur analysis to understand all of the components that might be created in the process.

10.1.2 Technical and Economic Viability

In summary, the project has demonstrated that the EnCAID process is a technically sound method of recovering GOB gas. The drastic decline in natural gas prices over the project period has significantly impacted project economics. At the end of 2010 Cenovus was working on obtaining the necessary regulatory and partner approval to bring on 4 additional producers at the far west end of the pool. Due to the low gas price environment, there are currently no other plans for expansion at this time.

Appendix A: 102/5-10-73-6W4 Observation Well Core Photos


ENCANA CORPORATION
MAY, 2006
ECA ECOG KIRBY 102/05-10-073-06W4M/0
RC12710
TOP CORE#1 440.00m
40.00
41.00
Frame 1
BOTTOM 441.90m
AGAT Laboratories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ECA ECOG KIRBY 102/05-10-073-06W4M/0
TOP CORE#2 442.40m
MAY, 2006
RC12710
42.00
Frame 2
BOTTOM 443.60m
AGAT Laboratories


ENCANA CORPORATION
ECA ECOG KIRBY 102/05-10-073-06W4M/0
TOP CORE#3 444.00m
MAY, 2006
RC12710
44.00
45.00
OB 1
46.00
OB 2
47.00
OB 3
48.00
OB 4
Frame 3
BOTTOM 448.45m
AGAT Laboratories


ENCANA CORPORATION
ECA ECOG KIRBY 102/05-10-073-06W4M/0
TOP CORE#3 448.45m
MAY, 2006
RC12710
49.00
50.00
OB 5
Frame 4
BOTTOM 450.40m
AGAT Laboratories


ENCANA CORPORATION
ECA ECOG KIRBY 102/05-10-073-06W4M/0
TOP CORE#4 450.40m
MAY, 2006
RC12710
51.00
OB 6
52.00
53.00
OB 7
54.00
Frame 5
BOTTOM 454.53m
AGAT Laboratories


ENCANA CORPORATION
ECA ECOG KIRBY 102/05-10-073-06W4M/0
MAY, 2006
RC12710
TOP CORE#4 454.53m
55.00
OB 8
56.00
57.00
Frame 6
BOTTOM 457.40m
AGAT Laboratories


ENCANA CORPORATION
ECA ECOG KIRBY 102/05-10-073-06W4M/0
TOP CORE#5 457.40m
MAY, 2006
RC12710
58.00
59.00
OB 9
60.00
61.00
OB 10
Frame 7
BOTTOM 461.89m
AGAT Laboratories


ENCANA CORPORATION
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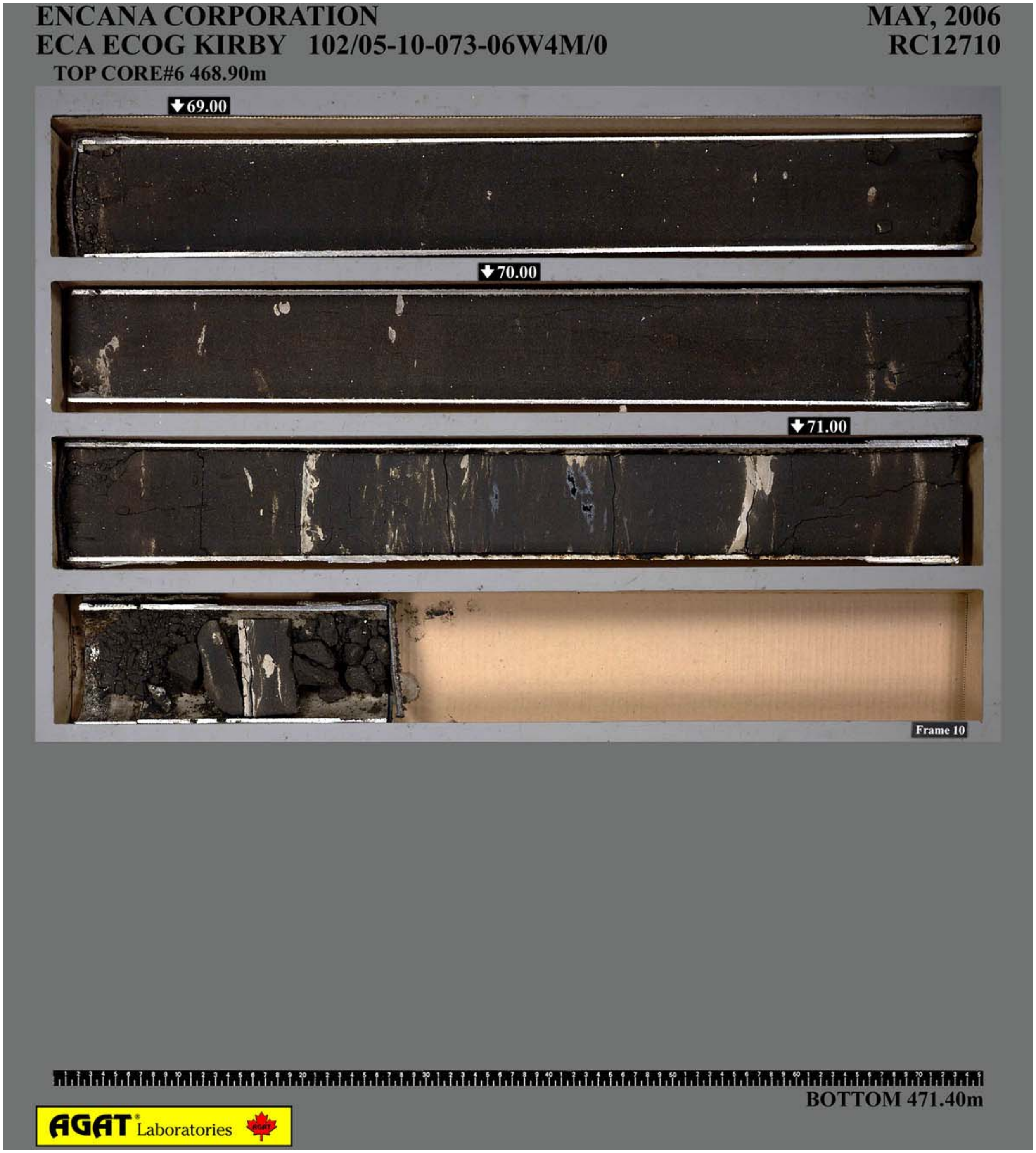
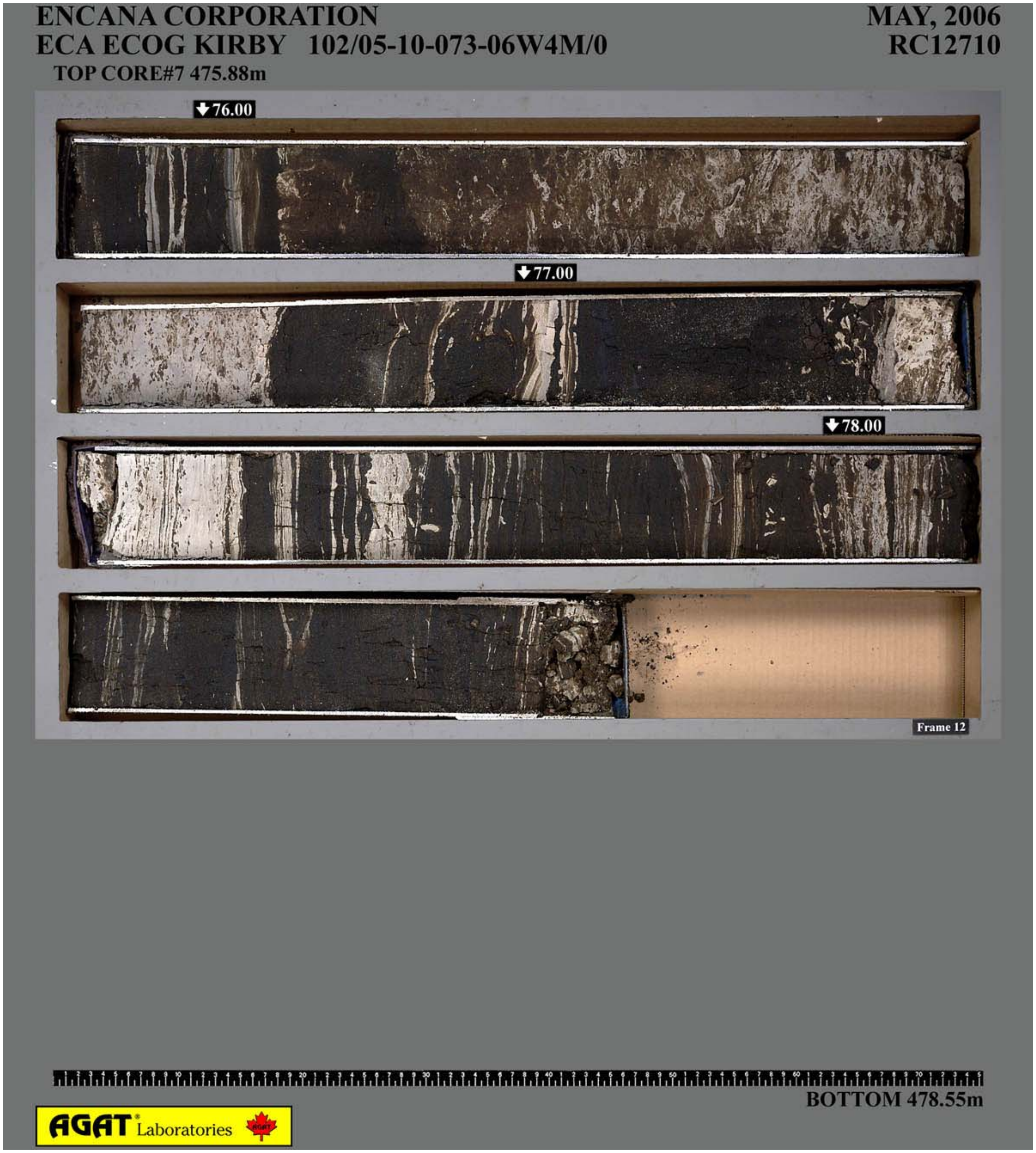
TOP CORE#5 461.89m
MAY, 2006
RC12710
62.00
OB 11
63.00
64.00
Frame 8
BOTTOM 464.40m
AGAT Laboratories


ENCANA CORPORATION
MAY, 2006
ECA ECOG KIRBY 102/05-10-073-06W4M/0
RC12710
TOP CORE#6 464.40m
65.00
66.00
67.00
OB 12
68.00
Frame 9
BOTTOM 468.90m
AGAT Laboratories


ENCANA CORPORATION
ECA ECOG KIRBY 102/05-10-073-06W4M/0
TOP CORE#6 468.90m
MAY, 2006
RC12710
69.00
70.00
71.00
Frame 10
BOTTOM 471.40m
AGAT Laboratories


ENCANA CORPORATION
ECA ECOG KIRBY 102/05-10-073-06W4M/0
TOP CORE#7 471.40m
MAY, 2006
RC12710
OB 13
72.00
73.00
74.00
75.00
Frame 11
BOTTOM 475.88m
AGAT Laboratories


ENCANA CORPORATION
ECA ECOG KIRBY 102/05-10-073-06W4M/0
TOP CORE#7 475.88m
MAY, 2006
RC12710
76.00
77.00
78.00
Frame 12
BOTTOM 478.55m
AGAT Laboratories

Appendix B: 102/5-10-73-6W4 Observation Well Core and Sieve Analysis

COMPANY : ENCANA CORPORATION
LOCATION : 102/05-10-073-06W4M/0
FORMATION : WABISKAW
WELL NAME : ECA ECOG KIRBY
DRILLING FLUID : WATER BASE MUD

PAGE : 1
DATE : 28-Apr-2006
W/O No : RC12710

HEAVY OIL SANDS ANALYSIS

Oil Density @ 1.000 g/cc
Grain Density @ 2.65 g/cc
OverBurden Pressure @ 1000 psi

	Interval (m)		Rep	Dean - Stark Analysis					Small Plug Analysis						
			Thick	(Bulk Mass)			Saturation		Permeability			Grain	(Pore Volume)		
				Oil	Water	Calc.	Oil	Water	KMax	Kv	Helium	Density	Oil	Water	
Sample	Top	Base	(m)	frac	frac	Porosity	frac	frac	(mD)	(mD)	Porosity	(Kg/m³)	frac	frac	Remarks
CORE NO. 1 440.00 - 442.40 (CUT / RECEIVED = 2.40 / 1.90 m TOTAL BOXES = 2)															
NA	440.00	441.90	1.90	-	-	-	-	-	-	-	-	-	-	-	sh:ss
LC	441.90	442.40	0.50	-	-	-	-	-	-	-	-	-	-	-	Lost Core
CORE NO. 2 442.40 - 444.00 (CUT / RECEIVED = 1.60 / 1.20 m TOTAL BOXES = 1)															
NA	442.40	443.60	1.20	-	-	-	-	-	-	-	-	-	-	-	sh:ss
LC	443.60	444.00	0.40	-	-	-	-	-	-	-	-	-	-	-	Lost Core
CORE NO. 3 444.00 - 450.40 (CUT / RECEIVED = 6.40 / 6.40 m TOTAL BOXES = 5)															
OB001	444.00	446.15	2.15	0.059	0.099	0.332	-	-	2620.	2140.	0.355	2620	0.334	0.557	ss:vf-fgr:arg
OB002	446.15	446.87	0.72	0.068	0.093	0.337	-	-	3020.	2270.	0.352	2630	0.393	0.541	ss:vf-fgr:arg
OB003	446.87	447.77	0.90	0.054	0.099	0.322	-	-	2120.	1930.	0.354	2610	0.303	0.555	ss:vf-fgr:arg
OB004	447.77	448.80	1.03	0.098	0.053	0.319	-	-	2120.	1260.	0.354	2610	0.552	0.296	ss:vf-fgr:arg
OB005	448.80	450.40	1.60	0.106	0.051	0.330	-	-	1910.	1570.	0.344	2600	0.622	0.303	ss:vf-fgr:arg
CORE NO. 4 450.40 - 457.40 (CUT / RECEIVED = 7.00 / 7.00 m TOTAL BOXES = 5)															
OB006	450.40	453.05	2.65	0.105	0.068	0.356	-	-	1500.	1200.	0.373	2630	0.561	0.363	ss:vf-fgr:arg
OB007	453.05	455.65	2.60	0.109	0.058	0.345	-	-	2030.	1260.	0.351	2600	0.626	0.334	ss:vf-fgr:arg
OB008	455.65	456.35	0.70	0.099	0.043	0.305	-	-	847.	786.	0.309	2620	0.679	0.296	ss:vf-fgr:arg
NA	456.35	457.40	1.05	-	-	-	-	-	-	-	-	-	-	-	ss
CORE NO. 5 457.40 - 464.40 (CUT / RECEIVED = 7.00 / 7.00 m TOTAL BOXES = 5)															
NA	457.40	457.88	0.48	-	-	-	-	-	-	-	-	-	-	-	ss

AGAT® Laboratories

COMPANY : ENCANA CORPORATION
LOCATION : 102/05-10-073-06W4M/0
FORMATION : WABISKAW
WELL NAME : ECA ECOG KIRBY
DRILLING FLUID : WATER BASE MUD

PAGE : 2
DATE : 28-Apr-2006
W/O No : RC12710

HEAVY OIL SANDS ANALYSIS

Oil Density @ 1.000 g/cc
Grain Density @ 2.65 g/cc
OverBurden Pressure @ 1000 psi

	Interval (m)		Rep	Dean - Stark Analysis (Bulk Mass)			Saturation		Small Plug Analysis Permeability			Grain	(Pore Volume)		
Sample	Top	Base	Thick (m)	Oil frac	Water frac	Calc. Porosity	Oil frac	Water frac	KMax (mD)	Kv (mD)	Helium Porosity	Density (Kg/m³)	Oil frac	Water frac	Remarks
OB009	457.88	460.51	2.63	0.100	0.068	0.348	-	-	1040.	854.	0.366	2620	0.547	0.373	ss:vf-fgr:arg:carbptg
NA	460.51	460.67	0.16	-	-	-	-	-	-	-	-	-	-	-	ss
OB010	460.67	461.89	1.22	0.102	0.049	0.319	-	-	1190.	696.	0.334	2610	0.626	0.299	ss:vf-fgr:arg
OB011	461.89	464.40	2.51	0.108	0.070	0.363	-	-	723.	700.	0.385	2610	0.547	0.353	ss:vf-fgr:arg:carbptg
CORE NO. 6 464.40 - 471.40 (CUT / RECEIVED = 7.00 / 7.00 m TOTAL BOXES = 5)															
011A	464.40	465.28	0.88	0.099	0.043	0.305	-	-	847.	786.	0.309	2620	0.679	0.296	ss:vf-fgr:arg ASTOB008
OB012	465.28	470.58	5.30	0.100	0.076	0.360	-	-	1270.	484.	0.378	2620	0.521	0.398	ss:vf-fgr:arg:carbptg
012A	470.58	471.40	0.82	0.099	0.043	0.305	-	-	847.	786.	0.309	2620	0.679	0.296	ss:vf-fgr:arg ASTOB008
CORE NO. 7 471.40 - 478.55 (CUT / RECEIVED = 7.15 / 7.15 m TOTAL BOXES = 5)															
OB013	471.40	474.49	3.09	0.096	0.051	0.313	-	-	621.	441.	0.320	2650	0.634	0.336	ss:vf-fgr:arg
NA	474.49	478.55	4.06	-	-	-	-	-	-	-	-	-	-	-	ss:sh

AGAT® Laboratories

COMPANY : ENCANA CORPORATION
LOCATION : 102/05-10-073-06W4M/0
FORMATION : WABISKAW
WELL NAME : ECA ECOG KIRBY
DRILLING FLUID : WATER BASE MUD

PAGE : 1
DATE : 28-Apr-2006
W/O No : RC12710A

HEAVY OIL SANDS ANALYSIS

Oil Density @ 1.000 g/cc
Grain Density @ 2.65 g/cc
OverBurden Pressure @ 1000 psi

	Interval (m)		Rep	Dean - Stark Analysis							Small Plug Analysis						
				(Bulk Mass)					Saturation		Permeability			Grain	(Pore Volume)		
			Thick	Oil	Water	Solids	Sum	Calc.	Oil	Water	KMax	Kv	Helium	Density	Oil	Water	
Sample	Top	Base	(m)	frac	frac	frac		Porosity	frac	frac	(mD)	(mD)	Porosity	(Kg/m³)	frac	frac	Remarks
				CORE NO. 1 440.00 - 442.40					(CUT / RECEIVED = 2.40 / 1.90 m					TOTAL BOXES = 2)			
NA	440.00	441.90	1.90	-	-	-	-	-	-	-	-		-	-	-	-	
LC	441.90	442.40	0.50	-	-	-	-	-	-	-	-		-	-	-	-	
				CORE NO. 2 442.40 - 444.00					(CUT / RECEIVED = 1.60 / 1.20 m					TOTAL BOXES = 1)			
NA	442.40	443.60	1.20	-	-	-	-	-	-	-	-		-	-	-	-	
LC	443.60	444.00	0.40	-	-	-	-	-	-	-	-		-	-	-	-	
				CORE NO. 3 444.00 - 450.40					(CUT / RECEIVED = 6.40 / 6.40 m					TOTAL BOXES = 5)			
NA	444.00	445.46	1.46	-	-	-	-	-	-	-	-		-	-	-	-	
DS1	445.46	445.76	0.30	0.055	0.112	0.833	1.000	0.347	0.329	0.671	-		-	-	-	-	
DS2	445.76	446.07	0.31	0.050	0.118	0.832	1.000	0.349	0.300	0.700	-		-	-	-	-	
DS3	446.07	446.36	0.29	0.057	0.113	0.831	1.000	0.351	0.335	0.665	-		-	-	-	-	
DS4	446.36	446.68	0.32	0.062	0.102	0.836	1.000	0.343	0.380	0.620	-		-	-	-	-	
DS5	446.68	446.96	0.28	0.062	0.108	0.830	1.000	0.352	0.366	0.634	-		-	-	-	-	
DS6	446.96	447.26	0.30	0.058	0.110	0.832	1.000	0.349	0.346	0.654	-		-	-	-	-	
DS7	447.26	447.55	0.29	0.054	0.115	0.831	1.000	0.351	0.320	0.680	-		-	-	-	-	
DS8	447.55	447.85	0.30	0.070	0.090	0.840	1.000	0.336	0.437	0.563	-		-	-	-	-	
DS9	447.85	448.16	0.31	0.086	0.085	0.829	1.000	0.354	0.500	0.500	-		-	-	-	-	
DS10	448.16	448.45	0.29	0.082	0.087	0.831	1.000	0.350	0.486	0.514	-		-	-	-	-	
DS11	448.45	448.75	0.30	0.104	0.065	0.831	1.000	0.350	0.615	0.385	-		-	-	-	-	

AGAT® Laboratories

COMPANY : ENCANA CORPORATION
LOCATION : 102/05-10-073-06W4M/0
FORMATION : WABISKAW
WELL NAME : ECA ECOG KIRBY
DRILLING FLUID : WATER BASE MUD

PAGE : 2
DATE : 28-Apr-2006
W/O No : RC12710A

HEAVY OIL SANDS ANALYSIS

Oil Density @ 1.000 g/cc
Grain Density @ 2.65 g/cc
OverBurden Pressure @ 1000 psi

	Interval (m)		Rep	Dean - Stark Analysis							Small Plug Analysis						
				(Bulk Mass)					Saturation		Permeability			Grain	(Pore Volume)		
			Thick	Oil	Water	Solids	Sum	Calc.	Oil	Water	KMax	Kv	Helium	Density	Oil	Water	
Sample	Top	Base	(m)	frac	frac	frac		Porosity	frac	frac	(mD)	(mD)	Porosity	(Kg/m³)	frac	frac	Remarks
DS12	448.75	449.05	0.30	0.108	0.059	0.833	1.000	0.346	0.648	0.352	-		-	-	-	-	
DS13	449.05	449.34	0.29	0.106	0.059	0.835	1.000	0.344	0.642	0.358	-		-	-	-	-	
DS14	449.34	449.64	0.30	0.102	0.055	0.843	1.000	0.331	0.647	0.353	-		-	-	-	-	
DS15	449.64	449.95	0.31	0.108	0.062	0.830	1.000	0.352	0.636	0.364	-		-	-	-	-	
DS16	449.95	450.40	0.45	0.107	0.065	0.828	1.000	0.355	0.621	0.379	-		-	-	-	-	
CORE NO. 4 450.40 - 457.40 (CUT / RECEIVED = 7.00 / 7.00 m TOTAL BOXES = 5)																	
DS17	450.40	450.70	0.30	0.101	0.068	0.832	1.000	0.349	0.597	0.403	-		-	-	-	-	
DS18	450.70	451.01	0.31	0.104	0.069	0.826	0.999	0.358	0.601	0.399	-		-	-	-	-	
DS19	451.01	451.25	0.24	0.111	0.064	0.825	1.000	0.360	0.632	0.368	-		-	-	-	-	
DS20	451.25	451.56	0.31	0.112	0.064	0.824	1.000	0.362	0.635	0.365	-		-	-	-	-	
DS21	451.56	451.79	0.23	0.102	0.072	0.827	1.000	0.357	0.586	0.414	-		-	-	-	-	
DS22	451.79	452.10	0.31	0.103	0.070	0.827	1.000	0.357	0.594	0.406	-		-	-	-	-	
DS23	452.10	452.40	0.30	0.109	0.064	0.827	1.000	0.356	0.628	0.372	-		-	-	-	-	
DS24	452.40	452.70	0.30	0.100	0.065	0.835	1.000	0.343	0.606	0.394	-		-	-	-	-	
DS25	452.70	453.00	0.30	0.099	0.077	0.824	1.000	0.361	0.563	0.437	-		-	-	-	-	
DS26	453.00	453.30	0.30	0.103	0.073	0.825	1.000	0.360	0.586	0.414	-		-	-	-	-	
DS27	453.30	453.60	0.30	0.098	0.076	0.826	1.000	0.358	0.565	0.435	-		-	-	-	-	
DS28	453.60	453.88	0.28	0.100	0.076	0.824	1.000	0.362	0.568	0.432	-		-	-	-	-	
DS29	453.88	454.19	0.31	0.099	0.070	0.831	1.000	0.349	0.587	0.413	-		-	-	-	-	
DS30	454.19	454.49	0.30	0.104	0.064	0.832	1.000	0.348	0.617	0.383	-		-	-	-	-	

AGAT® Laboratories

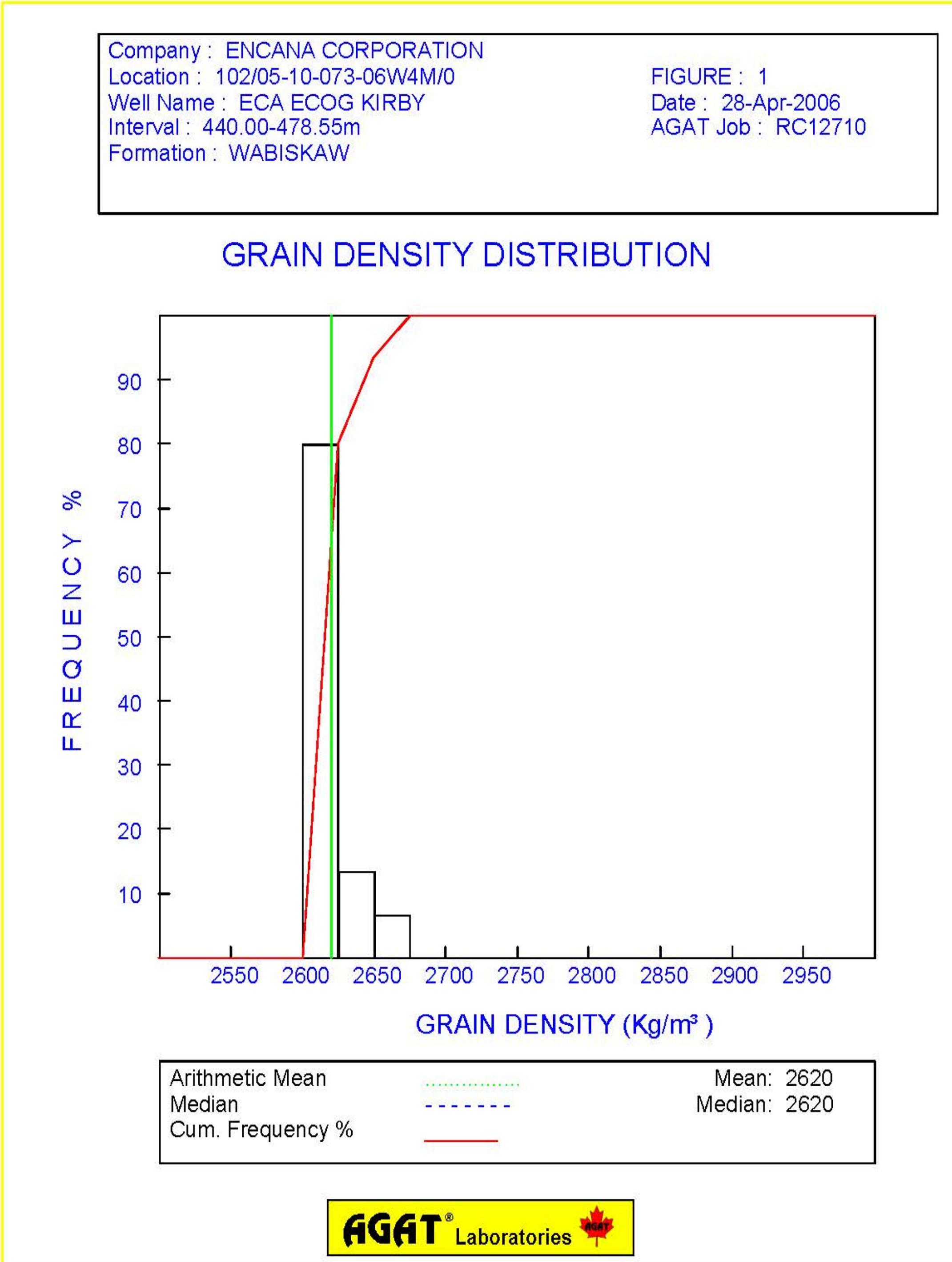
COMPANY	: ENCANA CORPORATION	PAGE	: 3
LOCATION	: 102/05-10-073-06W4M/0	DATE	: 28-Apr-2006
FORMATION	: WABISKAW	W/O No	: RC12710A
WELL NAME	: ECA ECOG KIRBY		
DRILLING FLUID	: WATER BASE MUD		

HEAVY OIL SANDS ANALYSIS

Oil Density @ 1.000 g/cc
Grain Density @ 2.65 g/cc
OverBurden Pressure @ 1000 psi

				Dean - Stark Analysis							Small Plug Analysis						
	Interval (m)		Rep	(Bulk Mass)					Saturation		Permeability			Grain	(Pore Volume)		
			Thick	Oil	Water	Solids	Sum	Calc.	Oil	Water	KMax	Kv	Helium	Density	Oil	Water	
Sample	Top	Base	(m)	frac	frac	frac		Porosity	frac	frac	(mD)	(mD)	Porosity	(Kg/m³)	frac	frac	Remarks
DS31	454.49	454.80	0.31	0.102	0.071	0.826	0.999	0.358	0.590	0.410	-	-	-	-	-		
DS32	454.80	455.10	0.30	0.105	0.065	0.829	0.999	0.353	0.617	0.383	-	-	-	-	-		
DS33	455.10	455.36	0.26	0.100	0.075	0.825	1.000	0.359	0.572	0.428	-	-	-	-	-		
DS34	455.36	455.67	0.31	0.094	0.080	0.826	1.000	0.358	0.542	0.458	-	-	-	-	-		
DS35	455.67	455.97	0.30	0.085	0.041	0.874	1.000	0.277	0.671	0.329	-	-	-	-	-		
DS36	455.97	456.35	0.38	0.092	0.078	0.830	1.000	0.352	0.543	0.457	-	-	-	-	-		
NA	456.35	457.40	1.05	-	-	-	-	-	-	-	-	-	-	-	-		
				CORE NO. 5 457.40 - 464.40					(CUT / RECEIVED = 7.00 / 7.00 m					TOTAL BOXES = 5)			
NA	457.40	458.88	1.48	-	-	-	-	-	-	-	-	-	-	-	-		
DS37	458.88	459.18	0.30	0.108	0.053	0.839	1.000	0.337	0.669	0.331	-	-	-	-	-		
NA	459.18	461.89	2.71	-	-	-	-	-	-	-	-	-	-	-	-		
DS38	461.89	462.19	0.30	0.103	0.069	0.828	1.000	0.355	0.600	0.400	-	-	-	-	-		
NA	462.19	464.40	2.21	-	-	-	-	-	-	-	-	-	-	-	-		
				CORE NO. 6 464.40 - 471.40					(CUT / RECEIVED = 7.00 / 7.00 m					TOTAL BOXES = 5)			
NA	464.40	465.90	1.50	-	-	-	-	-	-	-	-	-	-	-	-		
DS39	465.90	466.20	0.30	0.101	0.071	0.828	1.000	0.356	0.588	0.412	-	-	-	-	-		
NA	466.20	471.40	5.20	-	-	-	-	-	-	-	-	-	-	-	-		
				CORE NO. 7 471.40 - 478.55					(CUT / RECEIVED = 7.15 / 7.15 m					TOTAL BOXES = 5)			
NA	471.40	478.55	7.15	-	-	-	-	-	-	-	-	-	-	-	-		

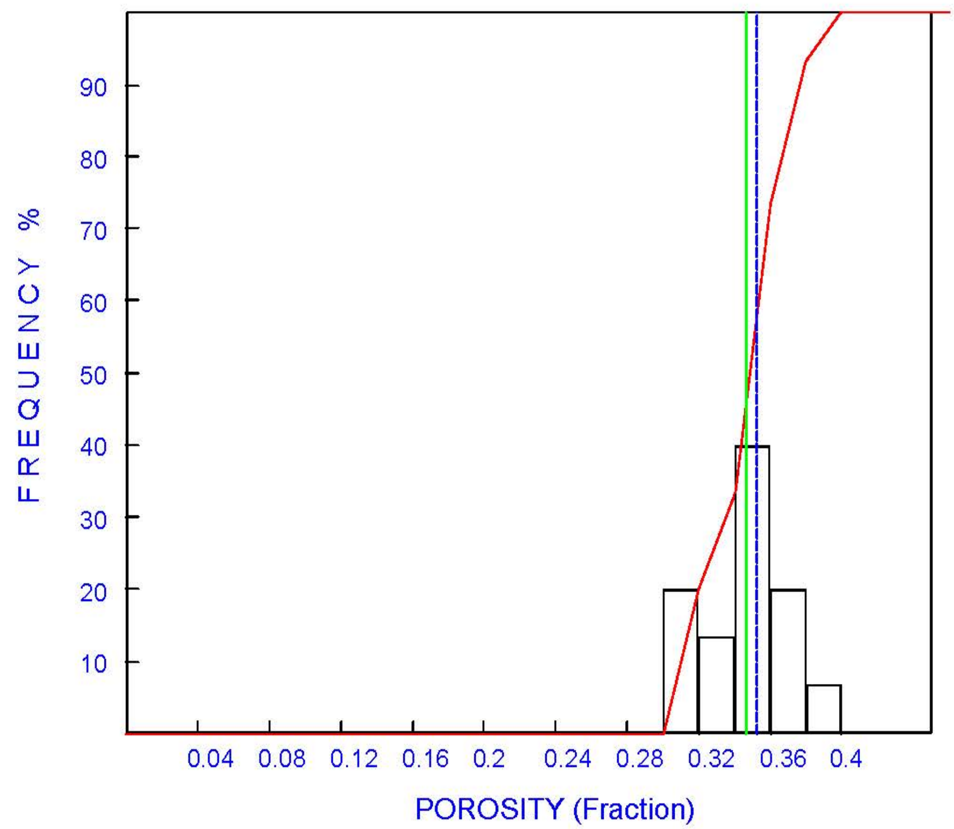
AGAT® Laboratories


Company : ENCANA CORPORATION
Location : 102/05-10-073-06W4M/0
Well Name : ECA ECOG KIRBY
Interval : 440.00-478.55m
Formation : WABISKAW
FIGURE : 1
Date : 28-Apr-2006
AGAT Job : RC12710
GRAIN DENSITY DISTRIBUTION
FREQUENCY %
90
80
70
60
50
40
30
20
10
2550
2600
2650
2700
2750
2800
2850
2900
2950
GRAIN DENSITY (Kg/m³)
Arithmetic Mean
Median
Cum. Frequency %
Mean: 2620
Median: 2620
AGAT Laboratories

Company : ENCANA CORPORATION
Location : 102/05-10-073-06W4M/0
Well Name : ECA ECOG KIRBY
Interval : 440.00-478.55m
Formation : WABISKAW

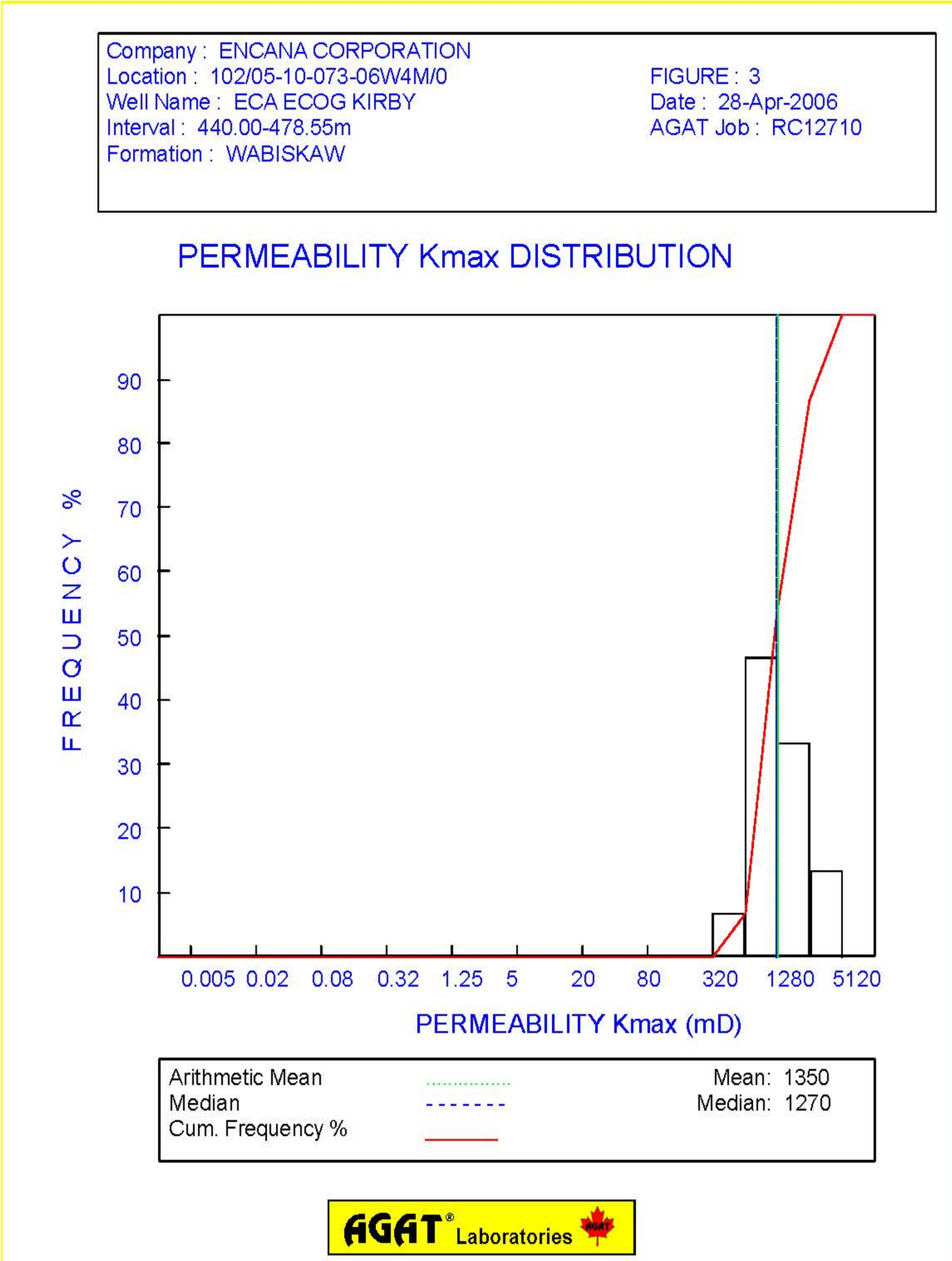
FIGURE : 2
Date : 28-Apr-2006
AGAT Job : RC12710

POROSITY DISTRIBUTION



Arithmetic Mean	Mean: 0.346
Median	Median: 0.352
Cum. Frequency %	

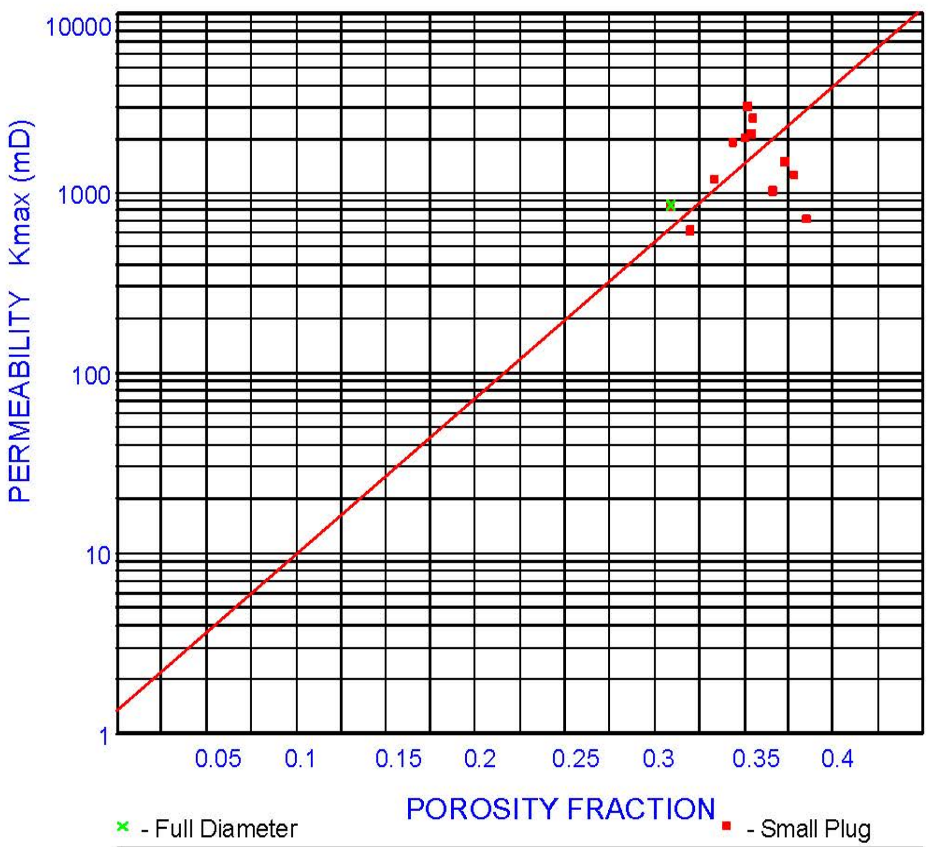
AGAT Laboratories


Company : ENCANA CORPORATION
Location : 102/05-10-073-06W4M/0
Well Name : ECA ECOG KIRBY
Interval : 440.00-478.55m
Formation : WABISKAW
FIGURE : 3
Date : 28-Apr-2006
AGAT Job : RC12710
PERMEABILITY Kmax DISTRIBUTION
FREQUENCY %
90
80
70
60
50
40
30
20
10
0.005 0.02 0.08 0.32 1.25 5 20 80 320 1280 5120
PERMEABILITY Kmax (mD)
Arithmetic Mean
Median
Cum. Frequency %
Mean: 1350
Median: 1270
AGAT Laboratories

Company : ENCANA CORPORATION
Location : 102/05-10-073-06W4M/0
Well Name : ECA ECOG KIRBY
Interval : 440.00-478.55m
Formation : WABISKAW

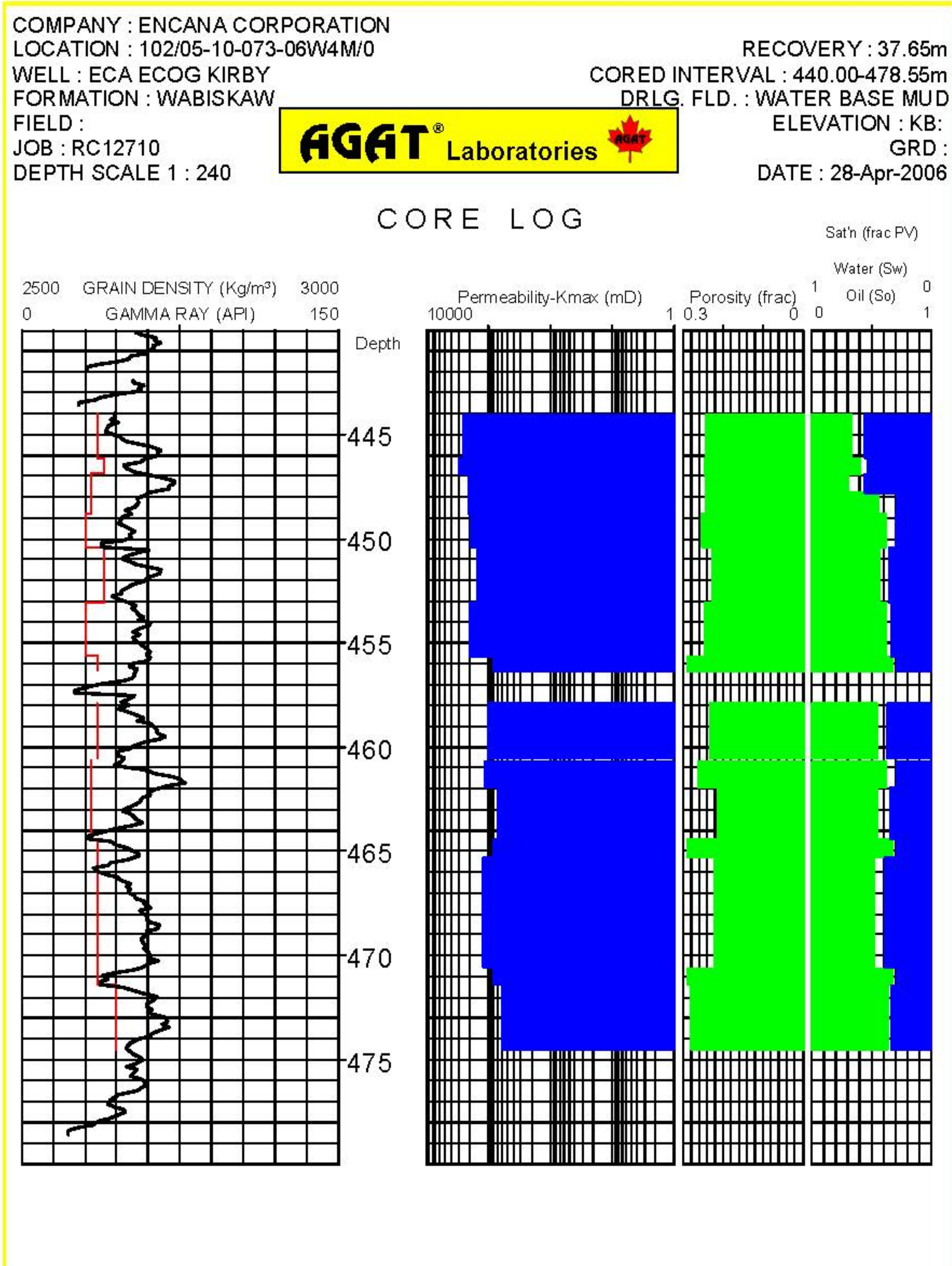
FIGURE : 4
Date : 28-Apr-2006
AGAT Job : RC12710

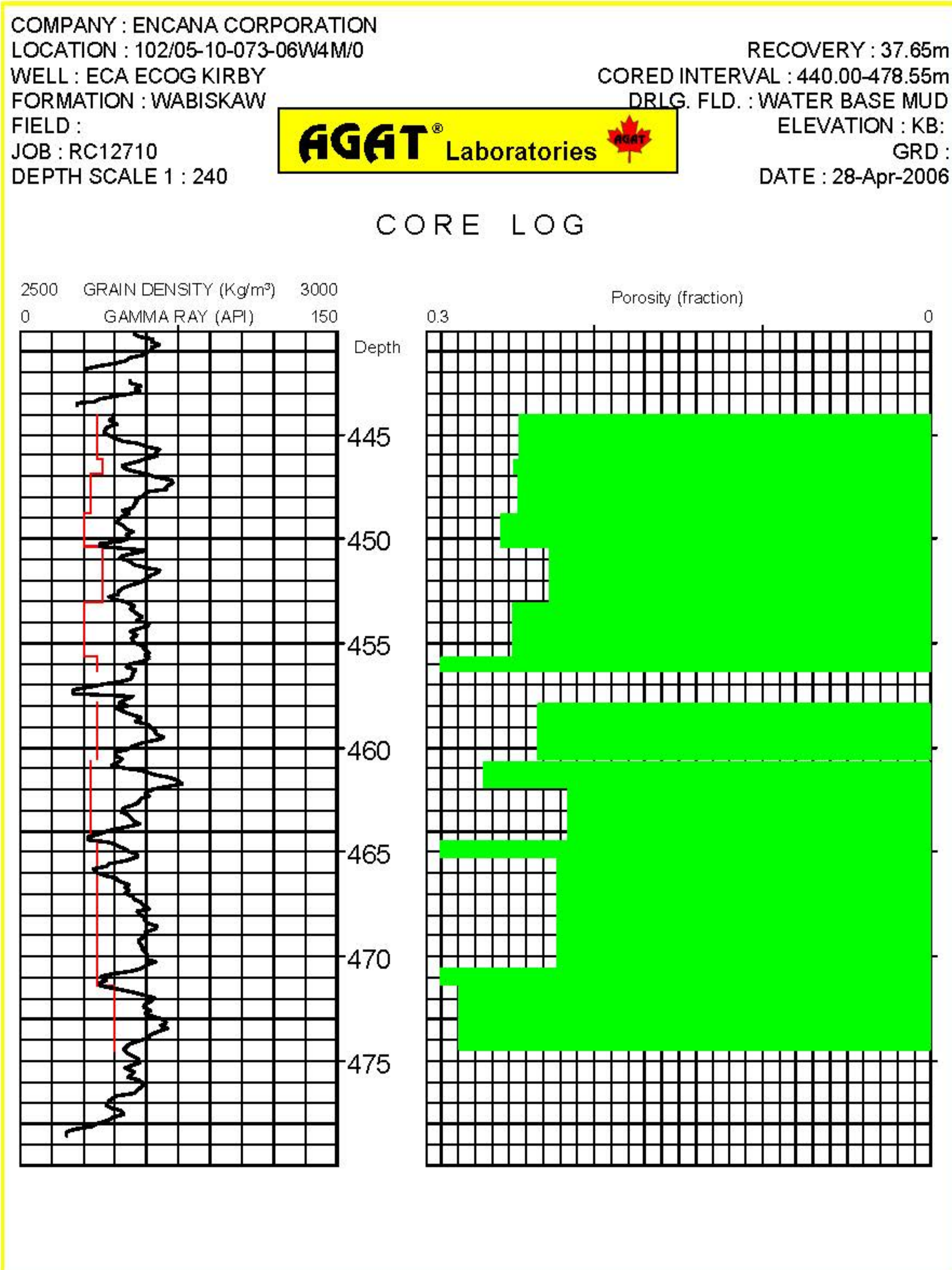
POROSITY-PERMEABILITY CORRELATION



Equation of Line : Log (Kmax) = 0.13 + 8.65* Porosity
Correlation Coefficient r = 0.36

AGAT® Laboratories


COMPANY : ENCANA CORPORATION
LOCATION : 102/05-10-073-06W4M/0
WELL : ECA ECOG KIRBY
FORMATION : WABISKAW
FIELD :
JOB : RC12710
DEPTH SCALE 1 : 240
AGAT Laboratories
RECOVERY : 37.65m
CORED INTERVAL : 440.00-478.55m
DRLG. FLD. : WATER BASE MUD
ELEVATION : KB:
GRD :
DATE : 28-Apr-2006
CORE LOG
2500 GRAIN DENSITY (Kg/m³) 3000
0 GAMMA RAY (API) 150
Depth
445
450
455
460
465
470
475
Permeability-Kmax (mD)
10000 1
Porosity (frac)
0.3 0
Sat'n (frac PV)
Water (Sw)
1 0
Oil (So)
0 1

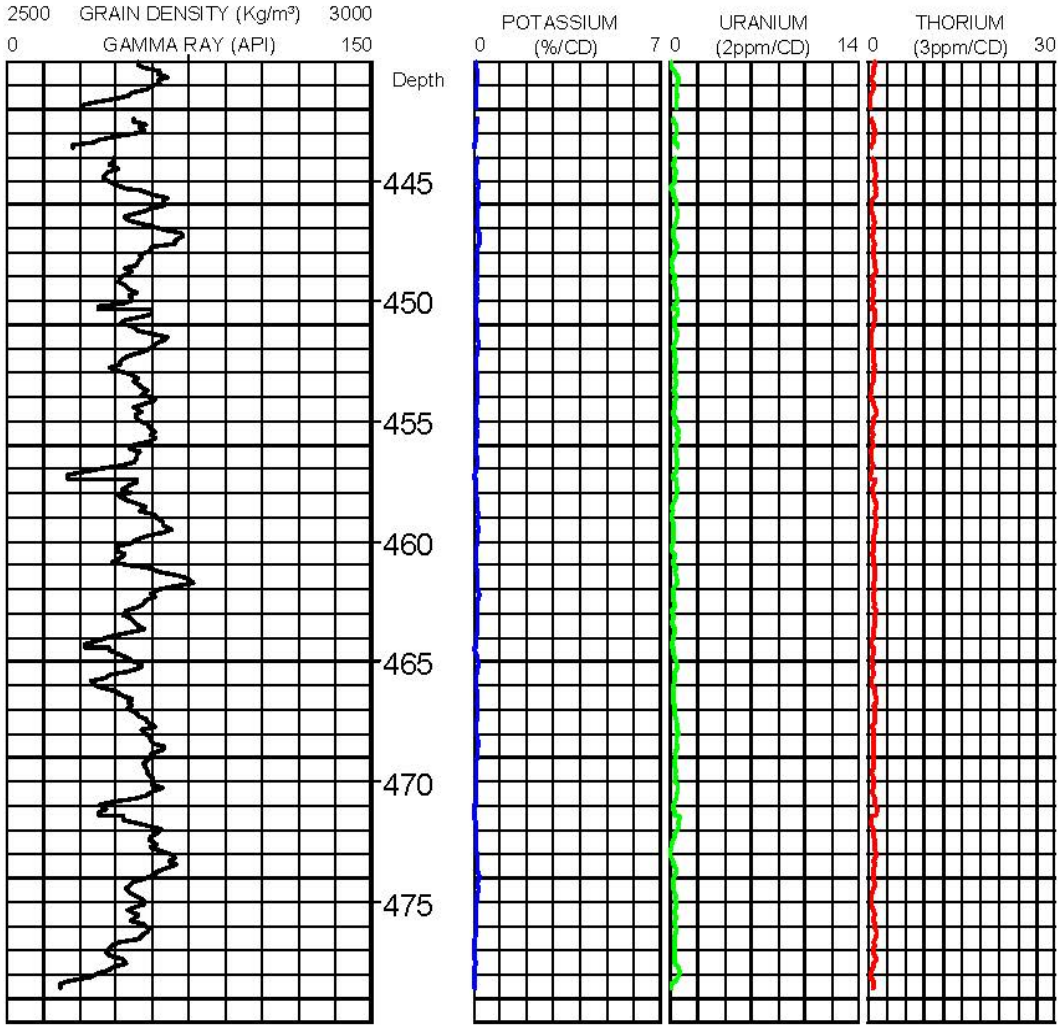

COMPANY : ENCANA CORPORATION
LOCATION : 102/05-10-073-06W4M/0
WELL : ECA ECOG KIRBY
FORMATION : WABISKAW
FIELD :
JOB : RC12710
DEPTH SCALE 1 : 240
RECOVERY : 37.65m
CORED INTERVAL : 440.00-478.55m
DRLG. FLD. : WATER BASE MUD
ELEVATION : KB:
GRD :
DATE : 28-Apr-2006
AGAT® Laboratories
CORE LOG
2500 GRAIN DENSITY (Kg/m³) 3000
0 GAMMA RAY (API) 150
Depth
Porosity (fraction)
0.3
0
445
450
455
460
465
470
475

COMPANY : ENCANA CORPORATION
LOCATION : 102/05-10-073-06W4M/0
WELL : ECA ECOG KIRBY
FORMATION : WABISKAW
FIELD :
JOB : RC12710
DEPTH SCALE 1 : 240

RECOVERY : 37.65m
CORED INTERVAL : 440.00-478.55m
DRLG. FLD. : WATER BASE MUD
ELEVATION : KB:
GRD :
DATE : 28-Apr-2006

AGAT® Laboratories

SPECTRAL GAMMA LOG



AGAT® Laboratories

PARTICLE SIZE ANALYSIS OF TEN SOLID SAMPLES

For

CENOVUS ENERGY INC.

RC12710

December 17, 2009

AGAT Laboratories

3650 - 21 Street N.E.
Calgary, Alberta
T2E 6V6

PARTICLE SIZE ANALYSIS

Ten solid samples for CENOVUS ENERGY INC. have been analyzed by AGAT Laboratories Ltd. for particle size distribution. The samples were analyzed using a "Coulter LS" Laser Diffraction particle size analyzer.

The results of the particle size analysis are summarized in the following table:

SAMPLE DESCRIPTION	D_{50}% [μm]	RANGE [μm]
Container ID: PSD 1 Type of the Sample: Solid LSD: 102/05-10-073-06W4M/0 Well Name: ECA ECOG KIRBY Depth: 446.00m Other Information: CORE 3, BOX2	171.4	0.393 – 324.4
Container ID: PSD 2 Type of the Sample: Solid LSD: 102/05-10-073-06W4M/0 Well Name: ECA ECOG KIRBY Depth: 449.50m Other Information: CORE 3, BOX4	135.1	0.393 – 324.4
Container ID: PSD 3 Type of the Sample: Solid LSD: 102/05-10-073-06W4M/0 Well Name: ECA ECOG KIRBY Depth: 453.50m Other Information: CORE 4, BOX3	155.1	0.393 – 324.4

Container ID: PSD 4 Type of the Sample: Solid LSD: 102/05-10-073-06W4M/0 Well Name: ECA ECOG KIRBY Depth: 455.00m Other Information: CORE 4, BOX4	156.0	0.393 – 295.5
Container ID: PSD 5 Type of the Sample: Solid LSD: 102/05-10-073-06W4M/0 Well Name: ECA ECOG KIRBY Depth: 459.00m Other Information: CORE 5, BOX2	165.9	0.393 – 356.1
Container ID: PSD 6 Type of the Sample: Solid LSD: 102/05-10-073-06W4M/0 Well Name: ECA ECOG KIRBY Depth: 462.00m Other Information: CORE 5, BOX4	155.9	0.393 – 324.4
Container ID: PSD 7 Type of the Sample: Solid LSD: 102/05-10-073-06W4M/0 Well Name: ECA ECOG KIRBY Depth: 465.00m Other Information: CORE 6, BOX1	131.6	0.393 – 356.1
Container ID: PSD 8 Type of the Sample: Solid LSD: 102/05-10-073-06W4M/0 Well Name: ECA ECOG KIRBY Depth: 469.50m	151.1	0.393 – 295.5

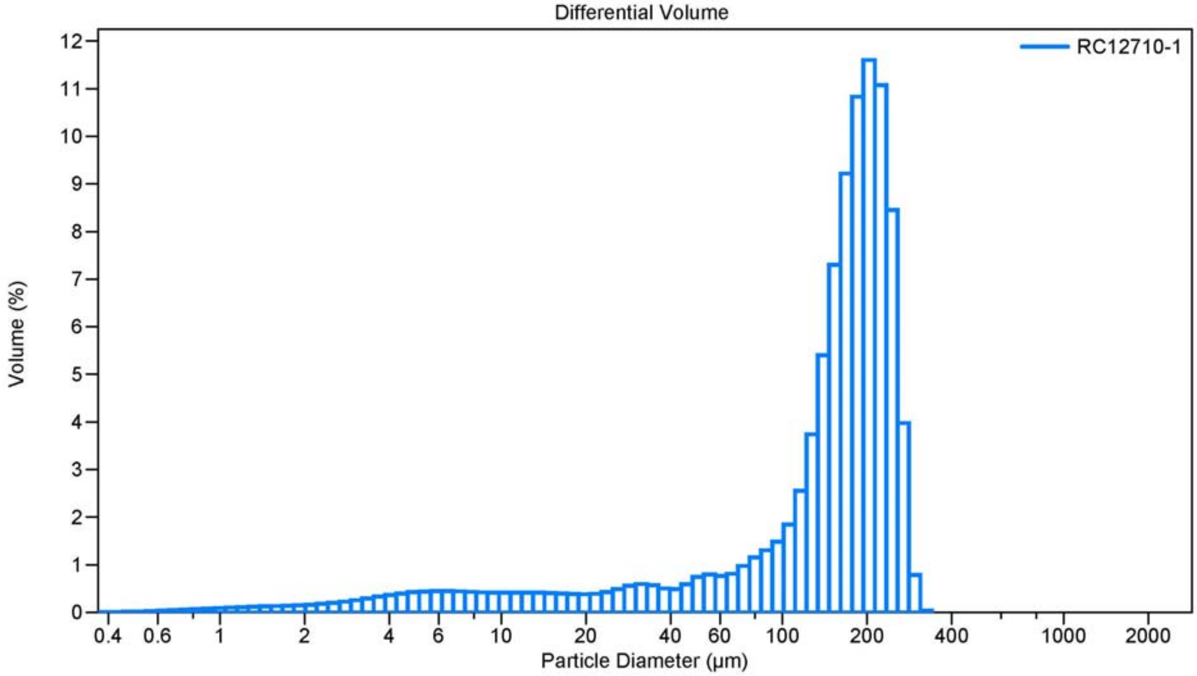
Other Information: CORE 6, BOX4		
Container ID: PSD 9 Type of the Sample: Solid LSD: 102/05-10-073-06W4M/0 Well Name: ECA ECOG KIRBY Depth: 474.00m Other Information: CORE 7, BOX2	145.5	0.393 – 390.9
Container ID: PSD 10 Type of the Sample: Solid LSD: 102/05-10-073-06W4M/0 Well Name: ECA ECOG KIRBY Depth: 475.40m Other Information: CORE 7, BOX3	152.7	0.393 – 390.9

The results are also presented in histogram and tabular format following the text.

BECKMAN COULTER

LS Particle Size Analyzer

File name:	RC12710-1	Group ID:	RC12710
Sample ID:	1	Bar Code:	ECA ECOG KIRBY
Run number:	1		
Comments:	INTERVAL: 446.00 LSD: 102/05-10-073-06W4M/0	Operator:	CENOVUS ENERGY INC.
Optical model:	Agat.rf780z		
LS 300	VSM+		
Start time:	9:26 17 Dec 2009	Run length:	60 seconds
Obscuration:	12%		
Fluid:	Water		
Software:	3.01 5.01	Firmware:	2.02 0

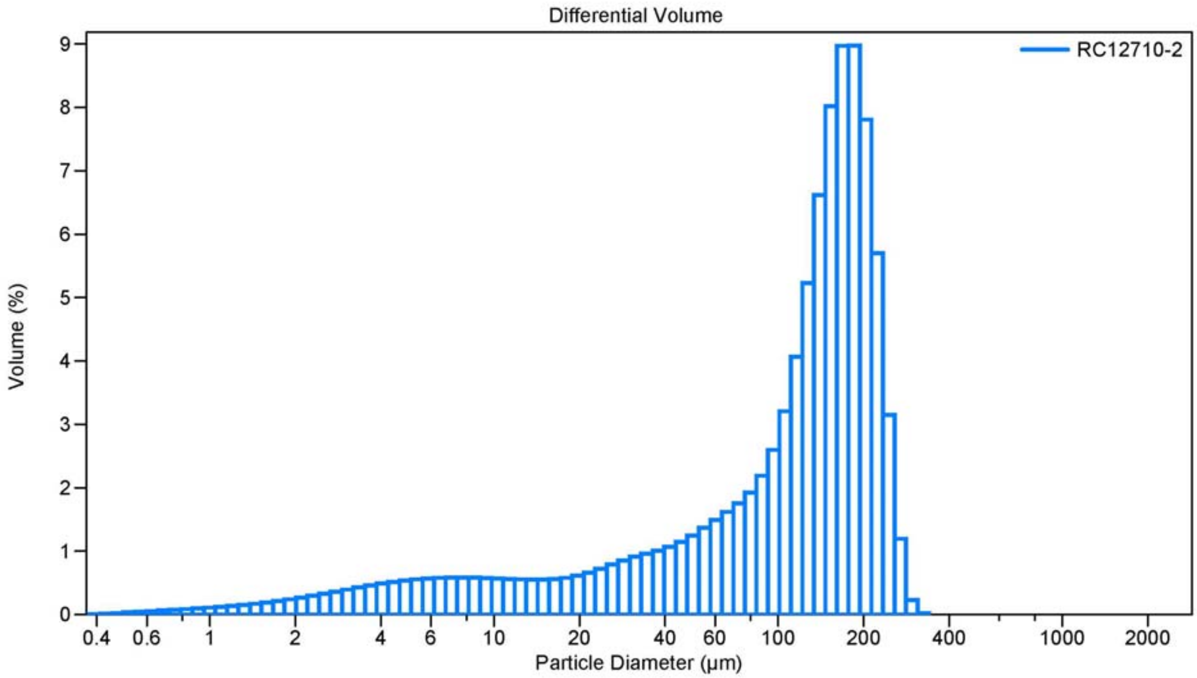


Volume Statistics (Arithmetic) RC12710-1

Calculations from 0.375 µm to 2,000 µm

Volume:	100%		
Mean:	154.8 µm	S.D.:	76.85 µm
Median:	171.4 µm	C.V.:	49.7%
Mode:	203.5 µm	Skewness:	-0.597 Left skewed
d_{10}:	18.40 µm	Kurtosis:	-0.618 Platykurtic
d_{50}:	171.4 µm		
d_{90}:	242.9 µm		

File name:	RC12710-2	Group ID:	RC12710
Sample ID:	2	Bar Code:	ECA ECOG KIRBY
Run number:	2		
Comments:	INTERVAL: 449.50 LSD: 102/05-10-073-06W4M/0	Operator:	CENOVUS ENERGY INC.
Optical model:	Agat.rf780z		
LS 300	VSM+		
Start time:	9:39 17 Dec 2009	Run length:	60 seconds
Obscuration:	11%		
Fluid:	Water		
Software:	3.01 5.01	Firmware:	2.02 0

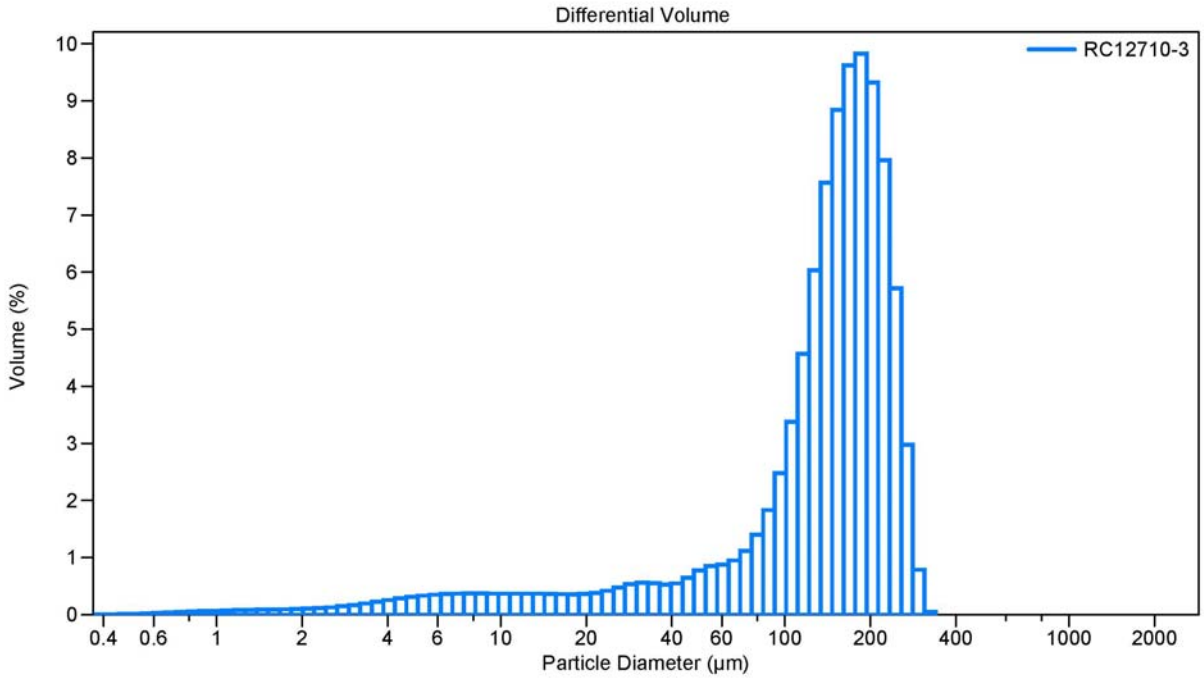


Volume Statistics (Arithmetic) RC12710-2

Calculations from 0.375 µm to 2,000 µm

Volume:	100%		
Mean:	123.0 µm	S.D.:	73.98 µm
Median:	135.1 µm	C.V.:	60.2%
Mode:	185.4 µm	Skewness:	-0.157 Left skewed
d_{10}:	9.899 µm	Kurtosis:	-1.055 Platykurtic
d_{50}:	135.1 µm		
d_{90}:	214.3 µm		

File name:	RC12710-3	Group ID:	RC12710
Sample ID:	3	Bar Code:	ECA ECOG KIRBY
Run number:	3		
Comments:	INTERVAL: 453.50 LSD: 102/05-10-073-06W4M/0	Operator:	CENOVUS ENERGY INC.
Optical model:	Agat.rf780z		
LS 300	VSM+		
Start time:	9:46 17 Dec 2009	Run length:	60 seconds
Obscuration:	9%		
Fluid:	Water		
Software:	3.01 5.01	Firmware:	2.02 0



Volume Statistics (Arithmetic) RC12710-3

Calculations from 0.375 µm to 2,000 µm

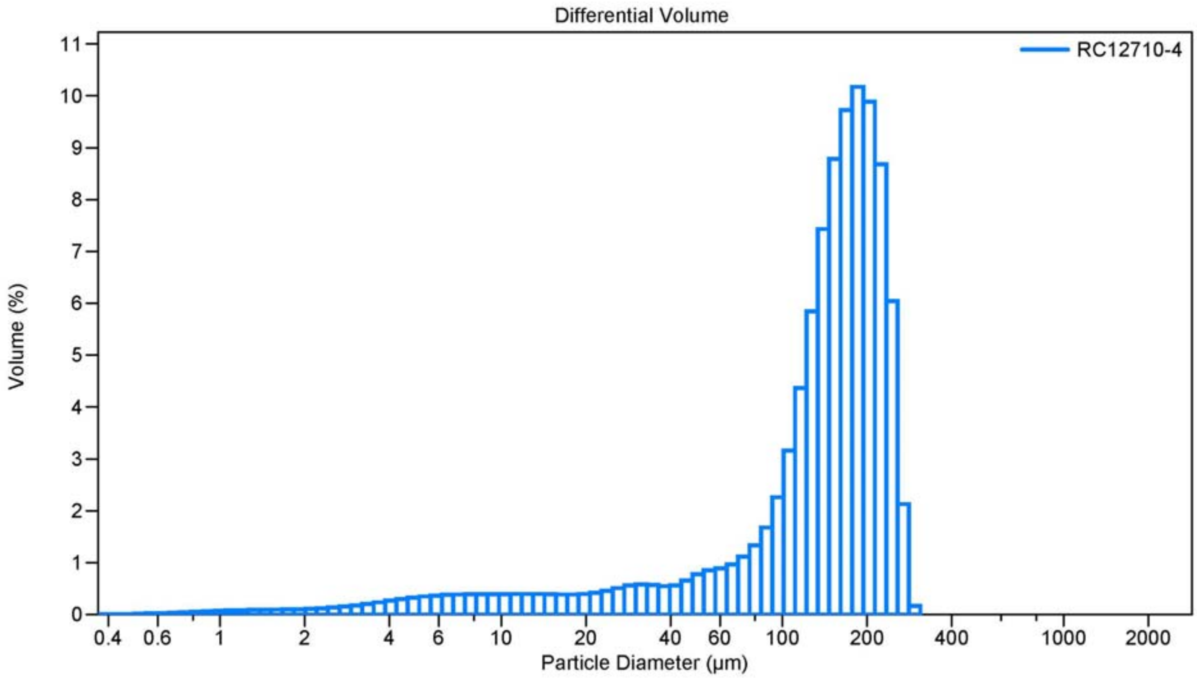
Volume:	100%		
Mean:	146.8 µm	S.D.:	70.81 µm
Median:	155.1 µm	C.V.:	48.2%
Mode:	185.4 µm	Skewness:	-0.391 Left skewed
d_{10}:	29.03 µm	Kurtosis:	-0.505 Platykurtic
d_{50}:	155.1 µm		
d_{90}:	232.8 µm		

BECKMAN COULTER

LS Particle Size Analyzer

17 Dec 2009 15:54

File name:	RC12710-4	Group ID:	RC12710
Sample ID:	4	Bar Code:	ECA ECOG KIRBY
Run number:	4		
Comments:	INTERVAL: 455.00 LSD: 102/05-10-073-06W4M/0	Operator:	CENOVUS ENERGY INC.
Optical model:	Agat.rf780z		
LS 300	VSM+		
Start time:	9:58 17 Dec 2009	Run length:	60 seconds
Obscuration:	8%		
Fluid:	Water		
Software:	3.01 5.01	Firmware:	2.02 0

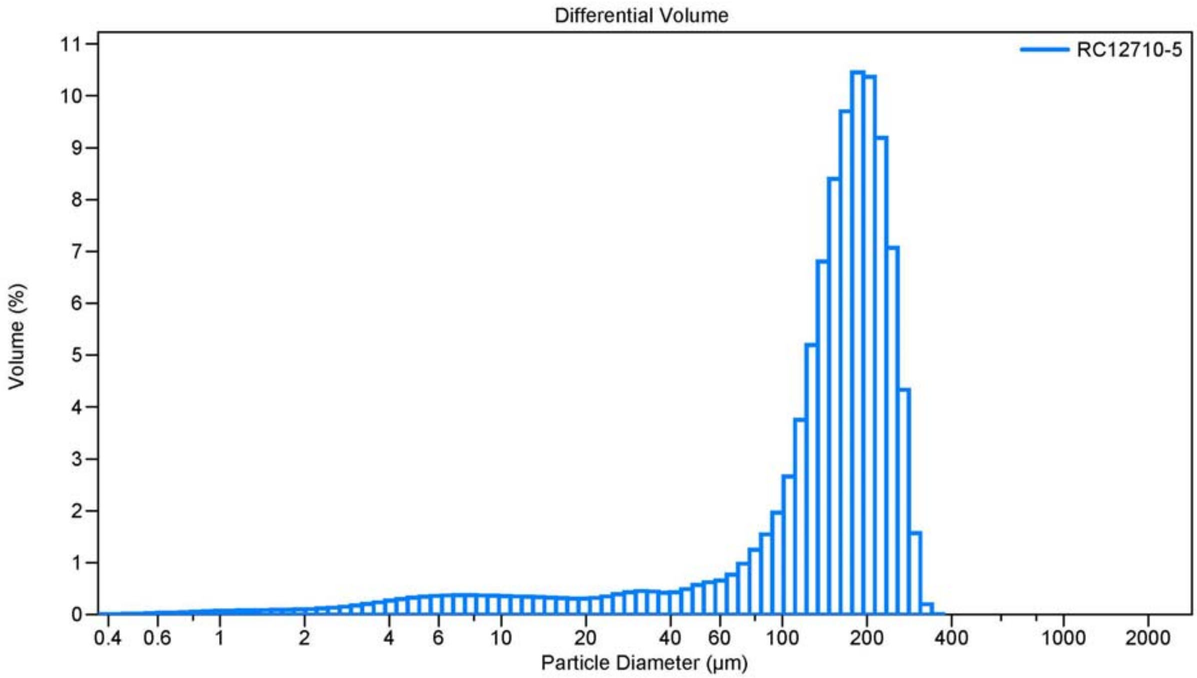


Volume Statistics (Arithmetic) RC12710-4

Calculations from 0.375 µm to 2,000 µm

Volume:	100%		
Mean:	145.6 µm	S.D.:	70.18 µm
Median:	156.0 µm	C.V.:	48.2%
Mode:	185.4 µm	Skewness:	-0.484 Left skewed
d_{10}:	26.29 µm	Kurtosis:	-0.567 Platykurtic
d_{50}:	156.0 µm		
d_{90}:	230.1 µm		

File name:	RC12710-5	Group ID:	RC12710
Sample ID:	5	Bar Code:	ECA ECOG KIRBY
Run number:	5		
Comments:	INTERVAL: 459.00 LSD: 102/05-10-073-06W4M/0	Operator:	CENOVUS ENERGY INC.
Optical model:	Agat.rf780z		
LS 300	VSM+		
Start time:	10:12 17 Dec 2009	Run length:	60 seconds
Obscuration:	7%		
Fluid:	Water		
Software:	3.01 5.01	Firmware:	2.02 0

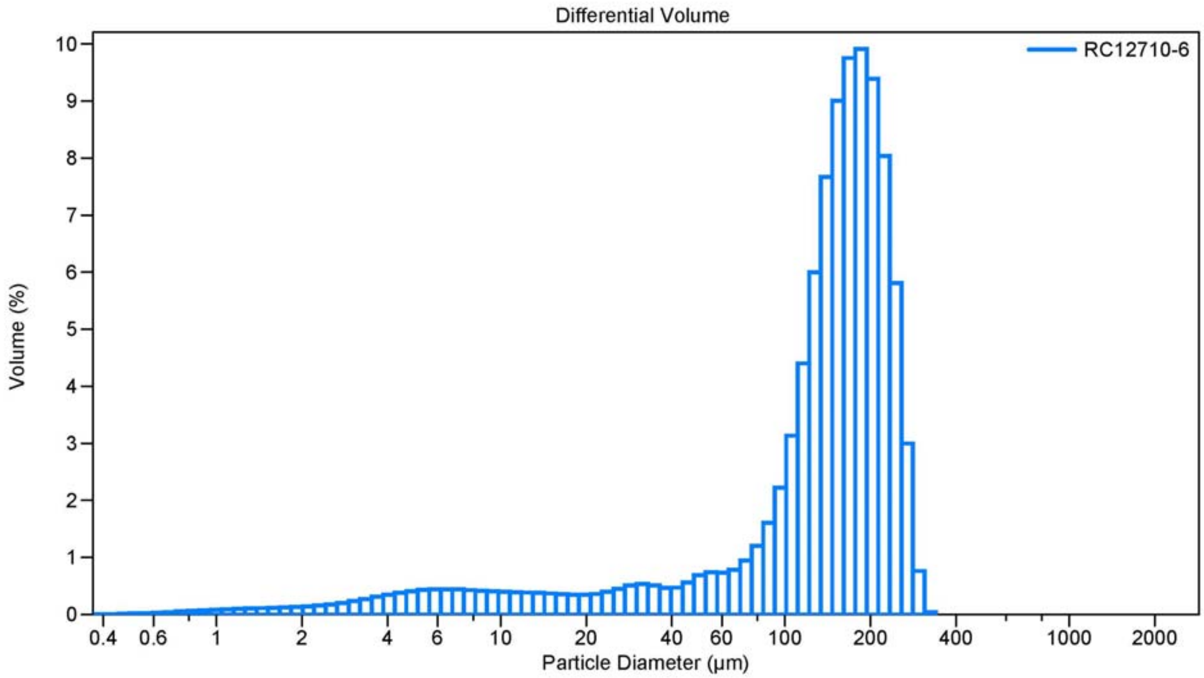


Volume Statistics (Arithmetic) RC12710-5

Calculations from 0.375 µm to 2,000 µm

Volume:	100%		
Mean:	156.4 µm	S.D.:	72.90 µm
Median:	165.9 µm	C.V.:	46.6%
Mode:	185.4 µm	Skewness:	-0.481 Left skewed
d_{10}:	32.23 µm	Kurtosis:	-0.365 Platykurtic
d_{50}:	165.9 µm		
d_{90}:	244.3 µm		

File name:	RC12710-6	Group ID:	RC12710
Sample ID:	6	Bar Code:	ECA ECOG KIRBY
Run number:	6		
Comments:	INTERVAL: 462.00 LSD: 102/05-10-073-06W4M/0	Operator:	CENOVUS ENERGY INC.
Optical model:	Agat.rf780z		
LS 300	VSM+		
Start time:	10:25 17 Dec 2009	Run length:	60 seconds
Obscuration:	11%		
Fluid:	Water		
Software:	3.01 5.01	Firmware:	2.02 0



Volume Statistics (Arithmetic) RC12710-6

Calculations from 0.375 µm to 2,000 µm

Volume:	100%		
Mean:	146.5 µm	S.D.:	72.12 µm
Median:	155.9 µm	C.V.:	49.2%
Mode:	185.4 µm	Skewness:	-0.439 Left skewed
d_{10}:	21.52 µm	Kurtosis:	-0.504 Platykurtic
d_{50}:	155.9 µm		
d_{90}:	233.1 µm		

LS Particle Size Analyzer

Page 1
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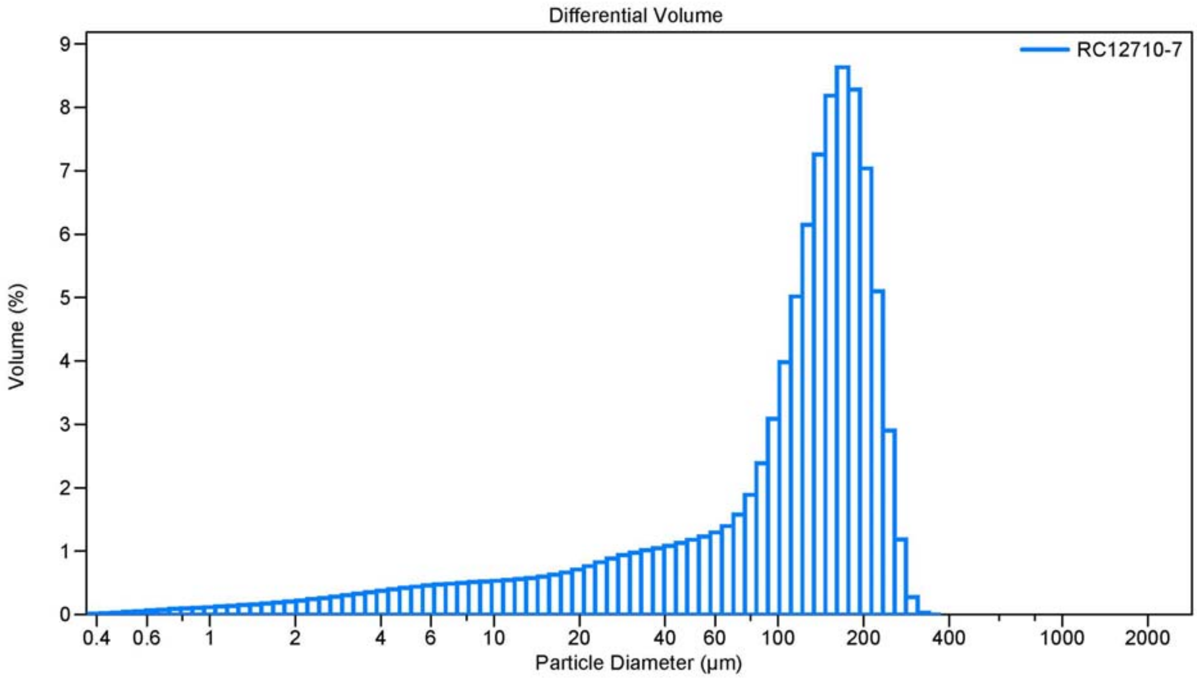
File name:	RC12710-7	Group ID:	RC12710
Sample ID:	7	Bar Code:	ECA ECOG KIRBY
Run number:	7		
Comments:	INTERVAL: 465.00 LSD: 102/05-10-073-06W4M/0	Operator:	CENOVUS ENERGY INC.
Optical model:	Agat.rf780z		
LS 300	VSM+		
Start time:	10:38 17 Dec 2009	Run length:	60 seconds
Obscuration:	12%		
Fluid:	Water		
Software:	3.01 5.01	Firmware:	2.02 0



Volume Statistics (Arithmetic) RC12710-7

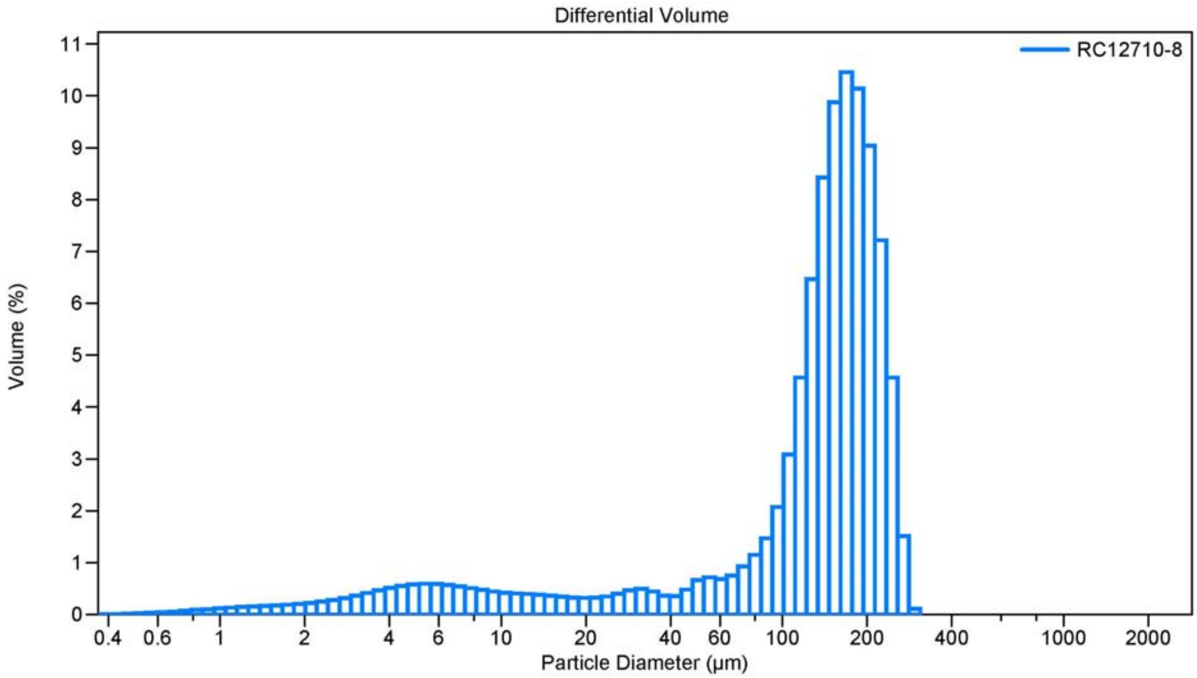
Calculations from 0.375 µm to 2,000 µm

Volume:	100%		
Mean:	122.2 µm	S.D.:	71.83 µm
Median:	131.6 µm	C.V.:	58.8%
Mode:	168.9 µm	Skewness:	-0.126 Left skewed
d_{10}:	12.83 µm	Kurtosis:	-0.940 Platykurtic
d_{50}:	131.6 µm		
d_{90}:	211.8 µm		

BECKMAN COULTER

LS Particle Size Analyzer

File name:	RC12710-8	Group ID:	RC12710
Sample ID:	8	Bar Code:	ECA ECOG KIRBY
Run number:	8		
Comments:	INTERVAL: 469.50 LSD: 102/05-10-073-06W4M/0	Operator:	CENOVUS ENERGY INC.
Optical model:	Agat.rf780z		
LS 300	VSM+		
Start time:	10:51 17 Dec 2009	Run length:	60 seconds
Obscuration:	12%		
Fluid:	Water		
Software:	3.01 5.01	Firmware:	2.02 0



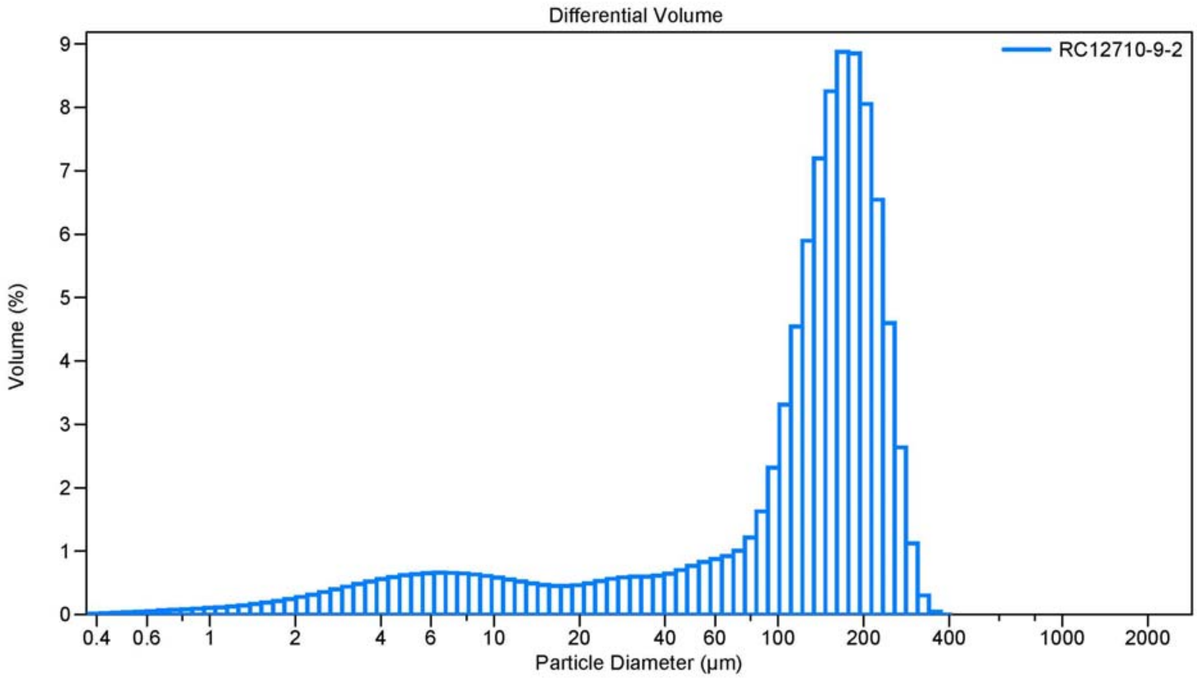
Volume Statistics (Arithmetic) RC12710-8

Calculations from 0.375 µm to 2,000 µm

Volume:	100%		
Mean:	139.0 µm	S.D.:	70.81 µm
Median:	151.1 µm	C.V.:	50.9%
Mode:	168.9 µm	Skewness:	-0.519 Left skewed
d_{10}:	11.14 µm	Kurtosis:	-0.561 Platykurtic
d_{50}:	151.1 µm		
d_{90}:	223.1 µm		

LS Particle Size Analyzer

File name:	RC12710-9-2	Group ID:	RC12710
Sample ID:	9	Bar Code:	ECA ECOG KIRBY
Run number:	9		
Comments:	INTERVAL: 474.00 LSD: 102/05-10-073-06W4M/0	Operator:	CENOVUS ENERGY INC.
Optical model:	Agat.rf780z		
LS 300	VSM+		
Start time:	11:11 17 Dec 2009	Run length:	60 seconds
Obscuration:	12%		
Fluid:	Water		
Software:	3.01 5.01	Firmware:	2.02 0



Volume Statistics (Arithmetic) RC12710-9-2

Calculations from 0.375 µm to 2,000 µm

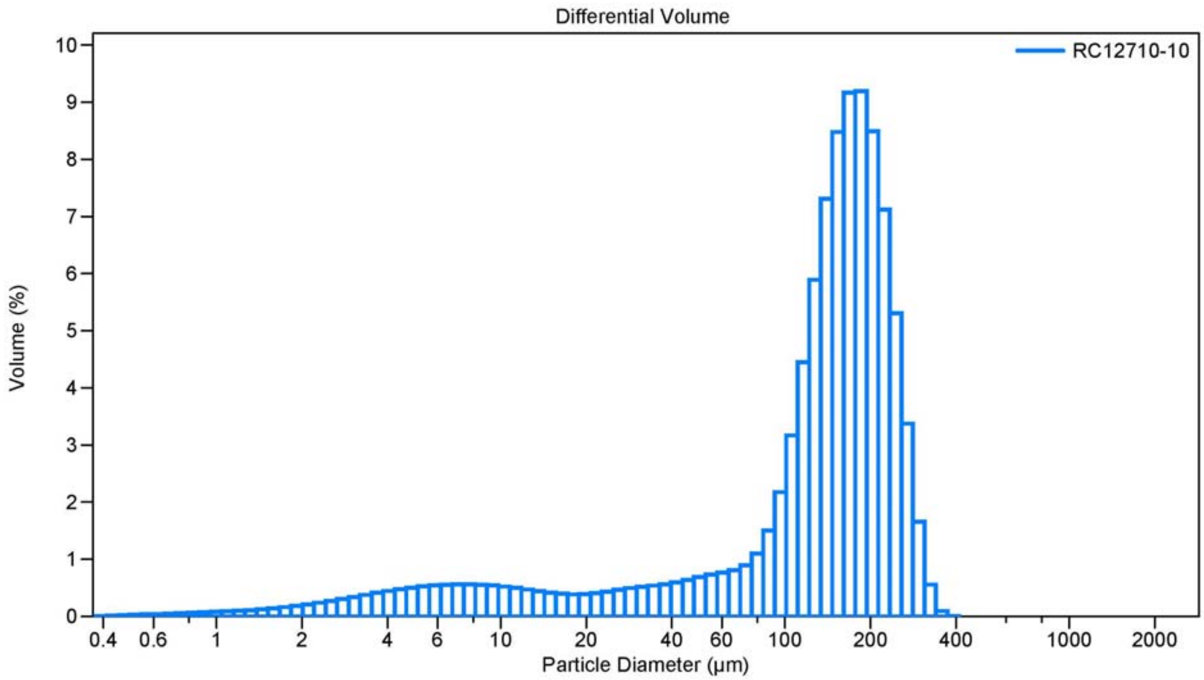
Volume:	100%		
Mean:	134.5 µm	S.D.:	77.96 µm
Median:	145.5 µm	C.V.:	57.9%
Mode:	168.9 µm	Skewness:	-0.213 Left skewed
d_{10}:	8.607 µm	Kurtosis:	-0.793 Platykurtic
d_{50}:	145.5 µm		
d_{90}:	229.9 µm		

5454545

LS Particle Size Analyzer

Page 1
17 Dec 2009 16:07

File name:	RC12710-10	Group ID:	RC12710
Sample ID:	10	Bar Code:	ECA ECOG KIRBY
Run number:	10		
Comments:	INTERVAL: 475.40 LSD: 102/05-10-073-06W4M/0	Operator:	CENOVUS ENERGY INC.
Optical model:	Agat.rf780z		
LS 300	VSM+		
Start time:	11:17 17 Dec 2009	Run length:	60 seconds
Obscuration:	12%		
Fluid:	Water		
Software:	3.01 5.01	Firmware:	2.02 0



Volume Statistics (Arithmetic) RC12710-10

Calculations from 0.375 µm to 2,000 µm

Volume:	100%		
Mean:	143.4 µm	S.D.:	77.71 µm
Median:	152.7 µm	C.V.:	54.2%
Mode:	185.4 µm	Skewness:	-0.255 Left skewed
d_{10}:	12.15 µm	Kurtosis:	-0.601 Platykurtic
d_{50}:	152.7 µm		
d_{90}:	238.3 µm		

Appendix C: 102/5-10-73-6W4 Observation Well Fluid Analysis

OIL CHARACTERIZATION
ECA ECOG KIRBY 102/05-10-073-06W4
WABISKAW

Prepared for:

ENCANA CORPORATION

2900 421-7th Avenue S.W.
Calgary, Alberta, Canada
T2P 4K9

Prepared by:

AGAT Laboratories
3700 - 21st Street N.E.
Calgary, AB
T2E 6V6

Telephone: (403) 299-2000

Work Order No: 06RE2384
Date: May 2006

TABLE OF CONTENTS

Work Order: 06RE 2384

1. List of Tables and figures

2. OBJECTIVE

Oil sand sample from core # 4 of well ECA ECOG KIRBY 102/05-10-073-06W4 was selected for oil extraction to determine density and viscosity at different temperature (13 C, 75 C and 150 C) and different pressure (800 kpag and 2500 kpag). Oil sand section was chosen from the depth intervals 450.40 m to 453.05 m of core # 4 below gas zone and above the largest CaCO3 tight streak. The samples were received in AGAT laboratory on April 26, 2006. Fluid characterization has been performed on the extracted oil according to client's specification and requirement.

And also three sections from core 3, 4 and 5 (core 4 below gas zone and above the largest CaCO3 tight streak, core 5 below the largest CaCO3 tight streak, and the Gas Zone to the Gas/Bitumen interface were selected for compositional analysis up to C30+ by using FID and SARA analysis to split the asphaltenes and maltenes.

3. EXPERIMENTAL PROCEDURE & DISCUSIÓN

The density of the oil is determined by displacing a known volume of the sample into a stainless steel pressure cylinder. The cylinder volume and weight are precisely measured prior to sampling. Without altering the pressure, the sample cylinder is filled with a measured volume of reservoir fluid. The sample cylinder is re-weighed on a scale accurate to 0.001 g and the density of the fluid is determined. The oil density results are presented in table 2 and figures 5-7.

The oil viscosity is determined using a calibrated magnetic viscometer (Cambridge 440). The magnetic viscometer is mounted within a temperature-controlled oven to maintain the desired thermal conditions. The temperature is controlled using a solid-state temperature controller accurate to ±0.5°C. An internally mounted thermometer is used to provide an exact reading of the system temperature. Circulating fans in the oven ensure a uniform temperature distribution in the system.

Also the oil viscosity was confirmed by cross arm viscometer under Oil Bath at different temperature and ambient pressure. All the experimental data and calculated results are presented in table 1 and figures 1 through 4.

The fluid was compositionally analyzed to C30+ by Flame Ionization Detection (Atmospheric And Pressurized Sample) is based on GPA 2186-02, GPA 2286-95, ASTM D 2597-94 and ASTM D 5307-97. This method is applicable to the determination of hydrocarbons in crude oils and gas condensates over a wide range of concentrations from C1 to C30. Hydrocarbon concentrations are reported in units of mole fraction. The compositions of the fluids are given in Tables 6-8.

SARA analysis was conducted on the extracted oil samples to split into Asphaltenes and Maltenes. The Asphaltenes was determined by ASTM D-4055-87 (Pentane Insoluble) from SARA analysis and shown as 16.31%Wt in core 3, 17.12%Wt in core 4 and 19.96%Wt in core 5. The SARA analysis was conducted using ASTM D2007-03 and the data was reported in both graphical and tabular format in Table 3-5 & Figures. 8-10 respectively.

4. COMMENTS

Table –1 presents the oil viscosity at ambient pressure, 800kpag and 2500kpag at different temperature. Figures 1–3 are depicted oil viscosity measured at ambient pressure, 800kpag and 2500 kPag. Figure 4 presents composite of oil viscosity at different pressure.

As can be seen in figure 4 there were no significant variations in oil viscosity on log – log scale.

Table –2 presents the density at 800kpag and 2500 kpag at different temperature. Figures 5–6 show density at 800 and 2500 kpag. Figure –7 shows composite density at different pressure

From graph in (Figure 7), by increasing the pressure (Ambient, 800 kpag to 2500kpag) at different temperature, the increase in density was insignificant.

Based on the data presented in the graph (Figure 7) density measured at 13 C and ambient pressure was 0.9965 g/cc.

.

Table 1: Viscosity at different pressure and temperature

Temp Cº	Viscosity at Ambient pressure	Viscosity at 800 kpag	Viscosity at 2500 kpag
13	128000	80000	90000
75	239.00	233.00	260.00
150	16.22	15.17	16.00

Figure 1: Fluid Viscosity mPa.s at Ambient pressure

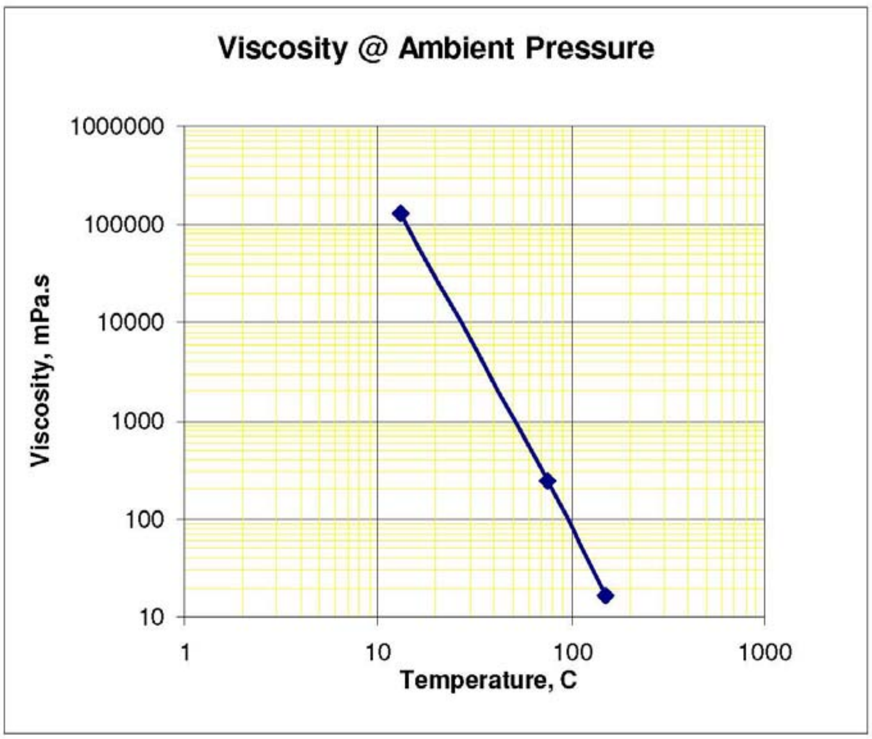


Figure 2: Fluid Viscosity mPa.s at 800 kpag

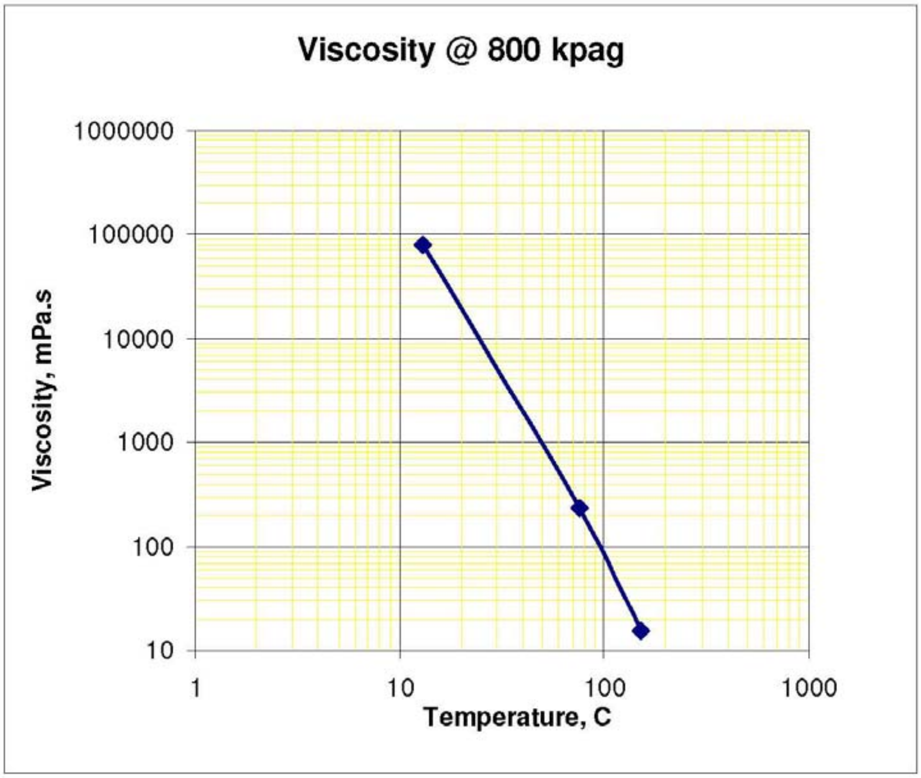


Figure 3: Fluid Viscosity mPa.s at 2500 kpag

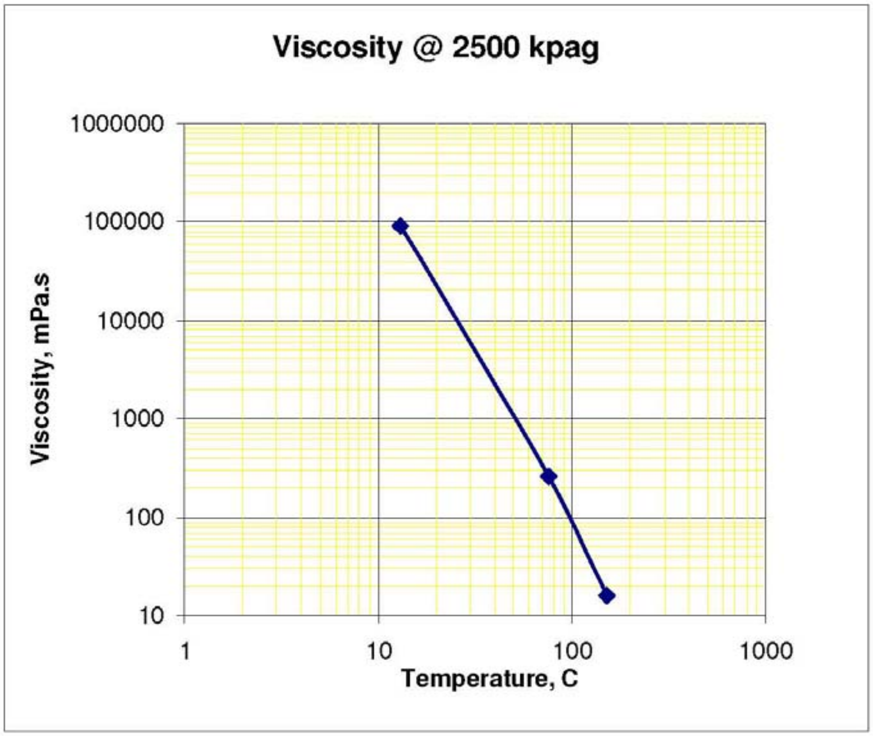


Figure 4: Fluid Viscosity at different pressure

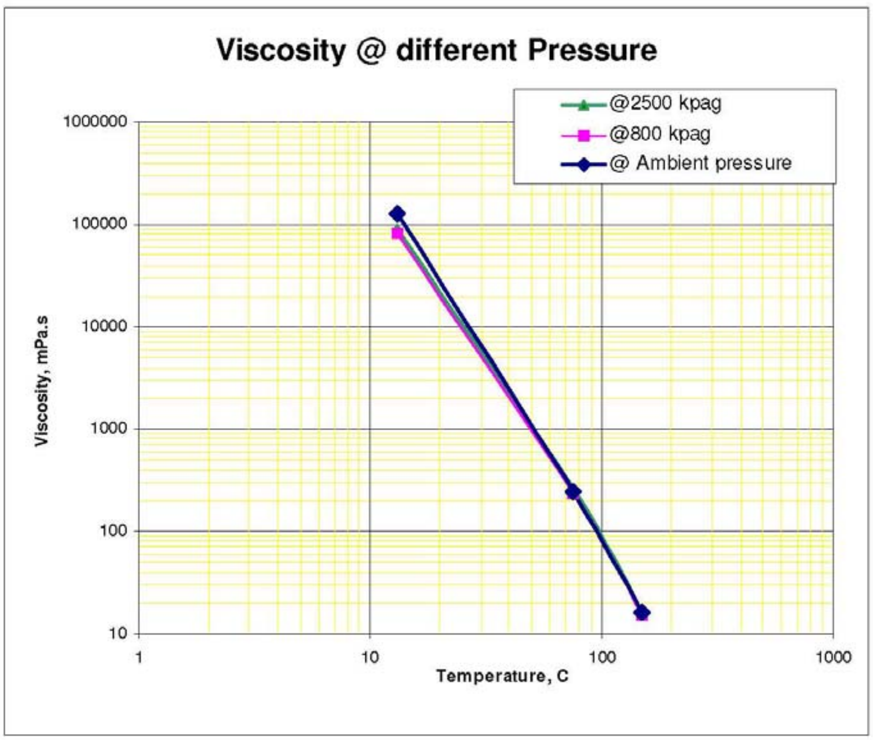


Table 2: Density, at different pressure

Temp Cº	Density g/cc @ Ambient pressure	Density g/cc @ 800 kpag	Density g/cc @ 2500 kpag
13	0.9956	0.9973	1.0008
75		0.9496	0.9524
150		0.9007	0.9025

Figure 5: Density at 800 kpag

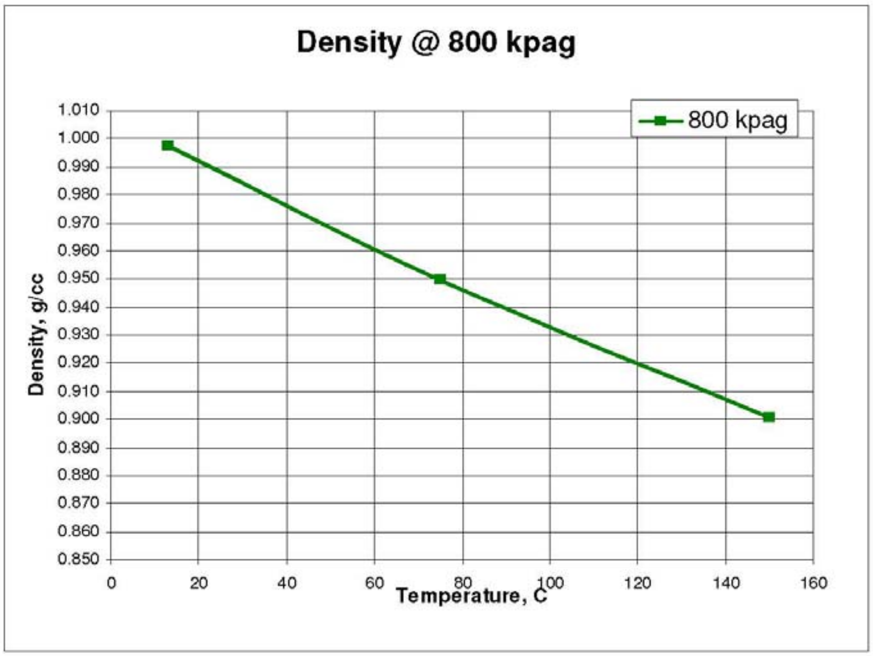


Figure 6: Density at 2500 kpag

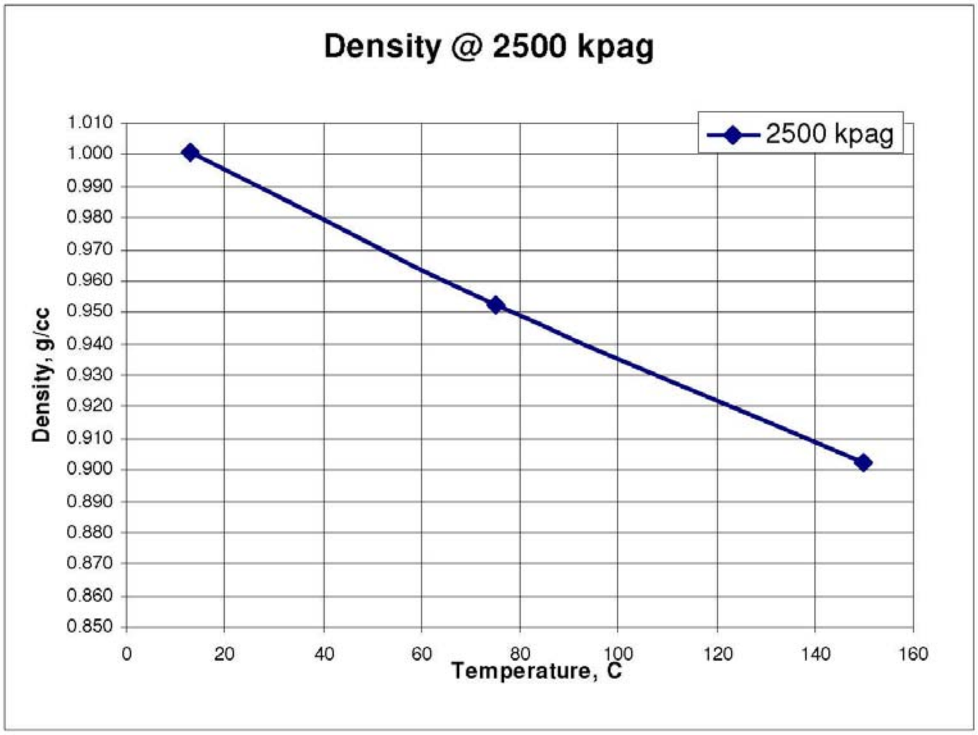


Figure 7: Density at different pressure

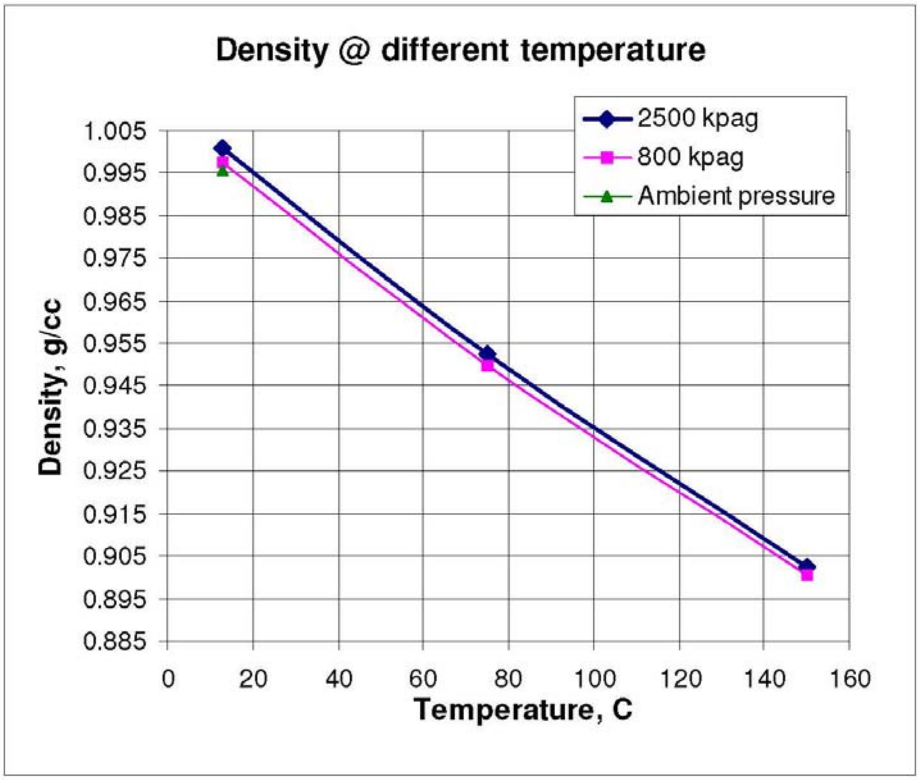


Table 3: Summary of SARA Analysis Data Core 3
(By ASTM D2007-03)

SARA	Mass %
Saturates	**26.21**
Aromatic	**47.25**
Resin	**9.42**
Ashphaltene	**17.12**

Figure 8: SARA Analysis Core 3

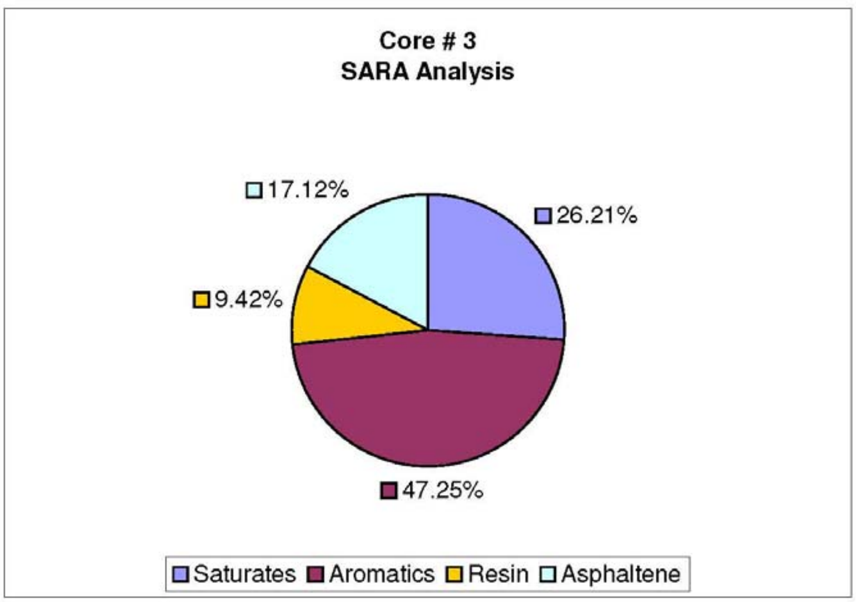


Table 4: Summary of SARA Analysis Data Core 4
(By ASTM D2007-03)

SARA	Mass %
Saturates	**24.78**
Aromatic	**44.95**
Resin	**10.31**
Ashphaltene	**19.96**

Figure 9: SARA Analysis Core 4

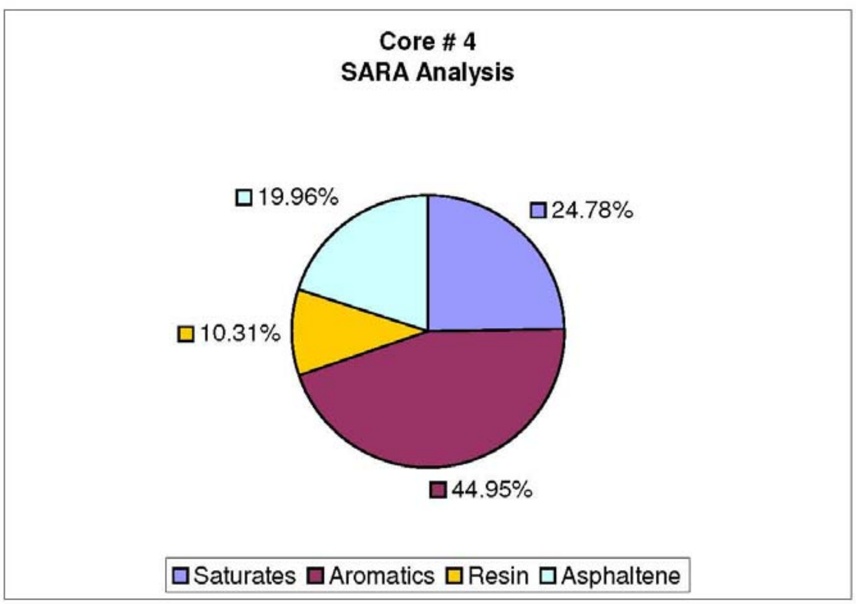


Table 5: Summary of SARA Analysis Data Core 5 (By ASTM D2007-03)

SARA	Mass %
Saturates	**28.22**
Aromatic	**45.71**
Resin	**9.76**
Ashphaltene	**16.31**

Figure 10: SARA Analysis Core 5

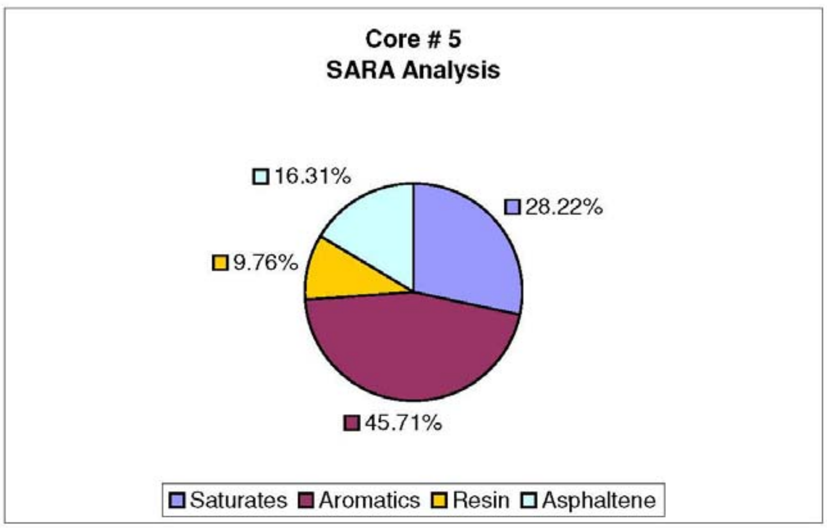


Table 6: Fluid's Composition Core 3

AGAT® Laboratories

HYDROCARBON LIQUID ANALYSIS

Container Identification
BAG1

Operator Name	Laboratory Number
ENCANA CORPORATION	06C166920A

Unique Well Identifier	Well Name	Elevation
102/05-10-073-06W4	ECA ECOG KIRBY 05-10-073-06W4	KB m / GRD m

Field or Area	Pool or Zone	Sampler's Company
KIRBY	NOT AVAILABLE	SAME

Test Type	Test No.	Test Recovery	Name of Sampler
		CORE 3 BOX 3	

Test Interval or Perfs	Sampling Point		Separator	Reservoir	Source	Sampled	Received
448.00-448.10 mKB		Pressure (kPa)					
		Temperature					

Well License	Date Sampled	Date Received	Date Reported	Entered By	Certified By
		Apr 26, 2006	May 19, 2006	CP & CT	CP

Other Information
RE#06RE2384

Note: Sampling Point, Unique Well Identifier and/or Pool or Zone information was unavailable at time of reporting. This information is integral to AGAT's WebFLUIDs, a comparison, history and trending analysis system.

COMP.	MOLE FRACTION	MASS FRACTION	VOLUME FRACTION
N2	0.0000	0.0000	0.0000
CO2	0.0000	0.0000	0.0000
H2S	0.0000	0.0000	0.0000
C1	0.0000	0.0000	0.0000
C2	0.0000	0.0000	0.0000
C3	0.0000	0.0000	0.0000
IC4	0.0000	0.0000	0.0000
NC4	0.0000	0.0000	0.0000
IC5	0.0000	0.0000	0.0000
NC5	0.0000	0.0000	0.0000
C6	0.0000	0.0000	0.0000
C7+	1.0000	1.0000	1.0000
TOTAL	**1.0000**	**1.0000**	**1.0000**

Exceeds normal limits: C7+

Observed Properties of C7+ Residue (15/15° C)

Density	*Relative Density*	*API @ 15°*
995.0 kg/m³	0.9959	10.6

Relative Molecular Mass
492.1

Calculated Properties of Total Sample (15/15° C)

Density	*Relative Density*	*API @ 15°*
995.0 kg/m³	0.9959	10.6

Relative Molecular Mass	*Gas Equivalency*
492.1	47.8

Calculations for C6 and C7 are based on Boiling Point Grouping. If Carbon Number Grouping had been done, the mole fractions would be (C6: 0.0000) (C7+:1.0000)

AGAT® Laboratories

PROPERTIES OF C6+ FRACTION

File No.	Company	UWI / LSD
06C166920A	ENCANA CORPORATION	102/05-10-073-06W4

BOILING POINT RANGE (C)	COMPONENT		MOLE FRACTION	MASS FRACTION	VOLUME FRACTION
36.1 - 68.9	HEXANES	C6	0.0000	0.0000	0.0000
68.9 - 98.3	HEPTANES	C7	0.0000	0.0000	0.0000
98.3 - 125.6	OCTANES	C8	0.0000	0.0000	0.0000
125.6 - 150.6	NONANES	C9	0.0000	0.0000	0.0000
150.6 - 173.9	DECANES	C10	0.0024	0.0013	0.0014
173.9 - 196.1	UNDECANES	C11	0.0128	0.0078	0.0083
196.1 - 215.0	DODECANES	C12	0.0122	0.0081	0.0085
215.0 - 235.0	TRIDECANES	C13	0.0425	0.0305	0.0316
235.0 - 252.2	TETRADECANES	C14	0.0711	0.0549	0.0564
252.2 - 270.6	PENTADECANES	C15	0.0899	0.0744	0.0758
270.6 - 287.8	HEXADECANES	C16	0.1039	0.0916	0.0927
287.8 - 302.8	HEPTADECANES	C17	0.1337	0.1252	0.1256
302.8 - 317.2	OCTADECANES	C18	0.0881	0.0873	0.0874
317.2 - 330.0	NONADECANES	C19	0.1111	0.1161	0.1157
330.0 - 344.4	EICOSANES	C20	0.0859	0.0945	0.0938
344.4 - 357.2	HENEICOSANES	C21	0.0830	0.0958	0.0947
357.2 - 369.4	DOCOSANES	C22	0.0560	0.0677	0.0667
369.4 - 380.0	TRICOSANES	C23	0.0480	0.0607	0.0595
380.0 - 391.1	TETRACOSANES	C24	0.0239	0.0315	0.0308
391.1 - 401.7	PENTACOSANES	C25	0.0031	0.0043	0.0042
401.7 - 412.2	HEXACOSANES	C26	0.0056	0.0080	0.0078
412.2 - 422.2	HEPTACOSANES	C27	0.0060	0.0088	0.0086
422.2 - 431.7	OCTACOSANES	C28	0.0044	0.0068	0.0066
431.7 - 441.1	NONACOSANES	C29	0.0038	0.0061	0.0059
441.1 - PLUS	TRIACONTANES	C30+	0.0108	0.0178	0.0172

BOILING POINT RANGE (C)	Aromatics		MOLE FRACTION	MASS FRACTION	VOLUME FRACTION
80.0	BENZENE	C6	0.0000	0.0000	0.0000
110.6	TOLUENE	C7	0.0000	0.0000	0.0000
136.2	ETHYLBENZENE	C8	0.0005	0.0002	0.0002
138.4 - 144.4	XYLENES	C8	0.0007	0.0003	0.0003
168.9	1,2,4 TRIMETHYLBENZENE	C9	0.0006	0.0003	0.0003

BOILING POINT RANGE (C)	Naphthenes		MOLE FRACTION	MASS FRACTION	VOLUME FRACTION
48.9	CYCLOPENTANE	CC5	0.0000	0.0000	0.0000
72.2	METHYLCYCLOPENTANE	MCC5	0.0000	0.0000	0.0000
81.1	CYCLOHEXANE	CC6	0.0000	0.0000	0.0000
101.1	METHYLCYCLOHEXANE	MCC6	0.0000	0.0000	0.0000

The above hexanes plus values are based upon a measured mass fraction and a calculated mole fraction, and assume a total hydrocarbon recovery from the chromatographic system.

Calgary AB, Ph: (403) 299-2000. Edmonton AB, Ph: (780) 469-0106. Grand Prairie AB, Ph: (780) 539-6500. Red Deer AB, Ph: (403) 346-6645.
Fort St. John BC, Ph: (250) 785-5500. Prince George BC, Ph: (250) 563-6011. Terrace BC, Ph: (250) 615-9288. Mississauga ON, Ph: (905) 501-9998.

Table 7: Fluid's Composition Core 4

AGAT® Laboratories

HYDROCARBON LIQUID ANALYSIS

Container Identification
BAG2

Operator Name	Laboratory Number
ENCANA CORPORATION	06C166920B

Unique Well Identifier	Well Name	Elevation
102/05-10-073-06W4	ECA ECOG KIRBY 05-10-073-06W4	KB m GRD m

Field or Area	Pool or Zone	Sampler's Company
KIRBY	NOT AVAILABLE	SAME

Test Type	Test No.	Test Recovery	Name of Sampler
		CORE 4 BOX 2	

Test Interval or Perfs		Sampling Point
452.30-452.40		
mKB		

	Separator	Reservoir	Source	Sampled	Received
Pressure (kPa)					
Temperature					

Well License	Date Sampled	Date Received	Date Reported	Entered By	Certified By
		Apr 26, 2006	May 19, 2006	CP & CT	CP

Other Information
RE#06RE2384

Note: Sampling Point, Unique Well Identifier and/or Pool or Zone information was unavailable at time of reporting. This information is integral to AGAT's WebFLUIDs, a comparison, history and trending analysis system.

COMP.	MOLE FRACTION	MASS FRACTION	VOLUME FRACTION
N2	0.0000	0.0000	0.0000
CO2	0.0000	0.0000	0.0000
H2S	0.0000	0.0000	0.0000
C1	0.0000	0.0000	0.0000
C2	0.0000	0.0000	0.0000
C3	0.0000	0.0000	0.0000
IC4	0.0000	0.0000	0.0000
NC4	0.0000	0.0000	0.0000
IC5	0.0000	0.0000	0.0000
NC5	0.0000	0.0000	0.0000
C6	0.0000	0.0000	0.0000
C7+	1.0000	1.0000	1.0000
TOTAL	**1.0000**	**1.0000**	**1.0000**

Exceeds normal limits: C7+

Observed Properties of C7+ Residue (15/15° C)

Density	*Relative Density*	*API @ 15°*
993.4 kg/m³	0.9943	10.8

Relative Molecular Mass
488.0

Calculated Properties of Total Sample (15/15° C)

Density	*Relative Density*	*API @ 15°*
993.4 kg/m³	0.9943	10.8

Relative Molecular Mass	*Gas Equivalency*
488.0	48.1

Calculations for C6 and C7 are based on Boiling Point Grouping. If Carbon Number Grouping had been done, the mole fractions would be (C6: 0.0000) (C7+:1.0000)

Calgary AB, Ph: (403) 299-2000. Edmonton AB, Ph: (780) 469-0106. Grand Prairie AB, Ph: (780) 539-6500. Red Deer AB, Ph: (403) 346-6645.
Fort St. John BC, Ph: (250) 785-5500. Prince George BC, Ph: (250) 563-6011. Terrace BC, Ph: (250) 615-9288. Mississauga ON, Ph: (905) 501-9998.

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AGAT® Laboratories

PROPERTIES OF C6+ FRACTION

File No.	Company	UWI / LSD
06C166920B	ENCANA CORPORATION	102/05-10-073-06W4

BOILING POINT RANGE (C)	COMPONENT		MOLE FRACTION	MASS FRACTION	VOLUME FRACTION
36.1 - 68.9	HEXANES	C6	0.0000	0.0000	0.0000
68.9 - 98.3	HEPTANES	C7	0.0000	0.0000	0.0000
98.3 - 125.6	OCTANES	C8	0.0002	0.0001	0.0001
125.6 - 150.6	NONANES	C9	0.0006	0.0003	0.0003
150.6 - 173.9	DECANES	C10	0.0061	0.0032	0.0034
173.9 - 196.1	UNDECANES	C11	0.0140	0.0081	0.0086
196.1 - 215.0	DODECANES	C12	0.0212	0.0134	0.0141
215.0 - 235.0	TRIDECANES	C13	0.0541	0.0371	0.0386
235.0 - 252.2	TETRADECANES	C14	0.0734	0.0542	0.0558
252.2 - 270.6	PENTADECANES	C15	0.0819	0.0647	0.0661
270.6 - 287.8	HEXADECANES	C16	0.0866	0.0729	0.0741
287.8 - 302.8	HEPTADECANES	C17	0.1008	0.0904	0.0914
302.8 - 317.2	OCTADECANES	C18	0.0636	0.0602	0.0605
317.2 - 330.0	NONADECANES	C19	0.0784	0.0782	0.0782
330.0 - 344.4	EICOSANES	C20	0.0612	0.0643	0.0640
344.4 - 357.2	HENEICOSANES	C21	0.0671	0.0740	0.0734
357.2 - 369.4	DOCOSANES	C22	0.0497	0.0574	0.0567
369.4 - 380.0	TRICOSANES	C23	0.0609	0.0735	0.0724
380.0 - 391.1	TETRACOSANES	C24	0.0311	0.0392	0.0385
391.1 - 401.7	PENTACOSANES	C25	0.0366	0.0479	0.0470
401.7 - 412.2	HEXACOSANES	C26	0.0349	0.0476	0.0466
412.2 - 422.2	HEPTACOSANES	C27	0.0248	0.0351	0.0343
422.2 - 431.7	OCTACOSANES	C28	0.0214	0.0314	0.0306
431.7 - 441.1	NONACOSANES	C29	0.0176	0.0268	0.0260
441.1 - PLUS	TRIACONTANES	C30+	0.0123	0.0193	0.0187

BOILING POINT RANGE (C)	Aromatics		MOLE FRACTION	MASS FRACTION	VOLUME FRACTION
80.0	BENZENE	C6	0.0000	0.0000	0.0000
110.6	TOLUENE	C7	0.0001	0.0001	0.0000
136.2	ETHYLBENZENE	C8	0.0002	0.0001	0.0001
138.4 - 144.4	XYLENES	C8	0.0005	0.0002	0.0002
168.9	1,2,4 TRIMETHYLBENZENE	C9	0.0007	0.0003	0.0003

BOILING POINT RANGE (C)	Naphthenes		MOLE FRACTION	MASS FRACTION	VOLUME FRACTION
48.9	CYCLOPENTANE	CC5	0.0000	0.0000	0.0000
72.2	METHYLCYCLOPENTANE	MCC5	0.0000	0.0000	0.0000
81.1	CYCLOHEXANE	CC6	0.0000	0.0000	0.0000
101.1	METHYLCYCLOHEXANE	MCC6	0.0000	0.0000	0.0000

The above hexanes plus values are based upon a measured mass fraction and a calculated mole fraction, and assume a total hydrocarbon recovery from the chromatographic system.

Table 8: Fluid's Composition Core 5

AGAT® Laboratories

HYDROCARBON LIQUID ANALYSIS

Container Identification
BAG3

Operator Name	Laboratory Number
ENCANA CORPORATION	06C166920C

Unique Well Identifier	Well Name	Elevation
102/05-10-073-06W4	ECA ECOG KIRBY 05-10-073-06W4	KB m GRD m

Field or Area	Pool or Zone	Sampler's Company
KIRBY	NOT AVAILABLE	SAME

Test Type	Test No.	Test Recovery	Name of Sampler
		CORE 5 BOX 2	

Test Interval or Perfs	Sampling Point		Separator	Reservoir	Source	Sampled	Received
458.98-459.06		Pressure (kPa)					
mKB		Temperature					

Well License	Date Sampled	Date Received	Date Reported	Entered By	Certified By
		Apr 26, 2006	May 19, 2006	CP &CT	CP

Other Information
RE#06RE2384

Note: Sampling Point, Unique Well Identifier and/or Pool or Zone information was unavailable at time of reporting. This information is integral to AGAT's WebFLUIDs, a comparison, history and trending analysis system.

COMP.	MOLE FRACTION	MASS FRACTION	VOLUME FRACTION
N2	0.0000	0.0000	0.0000
CO2	0.0000	0.0000	0.0000
H2S	0.0000	0.0000	0.0000
C1	0.0000	0.0000	0.0000
C2	0.0000	0.0000	0.0000
C3	0.0000	0.0000	0.0000
IC4	0.0000	0.0000	0.0000
NC4	0.0000	0.0000	0.0000
IC5	0.0000	0.0000	0.0000
NC5	0.0000	0.0000	0.0000
C6	0.0000	0.0000	0.0000
C7+	1.0000	1.0000	1.0000
TOTAL	**1.0000**	**1.0000**	**1.0000**

Exceeds normal limits: C7+

Observed Properties of C7+ Residue (15/15° C)

Density	*Relative Density*	*API @ 15°*
995.1 kg/m³	0.9960	10.6

Relative Molecular Mass
487.9

Calculated Properties of Total Sample (15/15° C)

Density	*Relative Density*	*API @ 15°*
995.1 kg/m³	0.9960	10.6

Relative Molecular Mass	*Gas Equivalency*
487.9	48.2

Calculations for C6 and C7 are based on Boiling Point Grouping. If Carbon Number Grouping had been done, the mole fractions would be (C6: 0.0000) (C7+:1.0000)

Calgary AB, Ph: (403) 299-2000. Edmonton AB, Ph: (780) 469-0106. Grand Prairie AB, Ph: (780) 539-6500. Red Deer AB, Ph: (403) 346-6645.
Fort St. John BC, Ph: (250) 785-5500. Prince George BC, Ph: (250) 563-6011. Terrace BC, Ph: (250) 615-9288. Mississauga ON, Ph: (905) 501-9998.

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AGAT® Laboratories

PROPERTIES OF C6+ FRACTION

File No.	Company	UWI / LSD
06C166920C	ENCANA CORPORATION	102/05-10-073-06W4

BOILING POINT RANGE (C)	COMPONENT		MOLE FRACTION	MASS FRACTION	VOLUME FRACTION
36.1 - 68.9	HEXANES	C6	0.0000	0.0000	0.0000
68.9 - 98.3	HEPTANES	C7	0.0000	0.0000	0.0000
98.3 - 125.6	OCTANES	C8	0.0002	0.0001	0.0001
125.6 - 150.6	NONANES	C9	0.0004	0.0002	0.0002
150.6 - 173.9	DECANES	C10	0.0065	0.0035	0.0038
173.9 - 196.1	UNDECANES	C11	0.0158	0.0093	0.0099
196.1 - 215.0	DODECANES	C12	0.0231	0.0148	0.0155
215.0 - 235.0	TRIDECANES	C13	0.0552	0.0384	0.0399
235.0 - 252.2	TETRADECANES	C14	0.0770	0.0577	0.0593
252.2 - 270.6	PENTADECANES	C15	0.0874	0.0701	0.0716
270.6 - 287.8	HEXADECANES	C16	0.0915	0.0782	0.0794
287.8 - 302.8	HEPTADECANES	C17	0.1051	0.0957	0.0962
302.8 - 317.2	OCTADECANES	C18	0.0669	0.0643	0.0645
317.2 - 330.0	NONADECANES	C19	0.0692	0.0702	0.0701
330.0 - 344.4	EICOSANES	C20	0.0662	0.0706	0.0703
344.4 - 357.2	HENEICOSANES	C21	0.0681	0.0763	0.0756
357.2 - 369.4	DOCOSANES	C22	0.0513	0.0602	0.0594
369.4 - 380.0	TRICOSANES	C23	0.0519	0.0636	0.0625
380.0 - 391.1	TETRACOSANES	C24	0.0383	0.0490	0.0481
391.1 - 401.7	PENTACOSANES	C25	0.0355	0.0473	0.0464
401.7 - 412.2	HEXACOSANES	C26	0.0299	0.0414	0.0405
412.2 - 422.2	HEPTACOSANES	C27	0.0216	0.0311	0.0303
422.2 - 431.7	OCTACOSANES	C28	0.0147	0.0220	0.0214
431.7 - 441.1	NONACOSANES	C29	0.0075	0.0116	0.0113
441.1 - PLUS	TRIACONTANES	C30+	0.0147	0.0235	0.0228

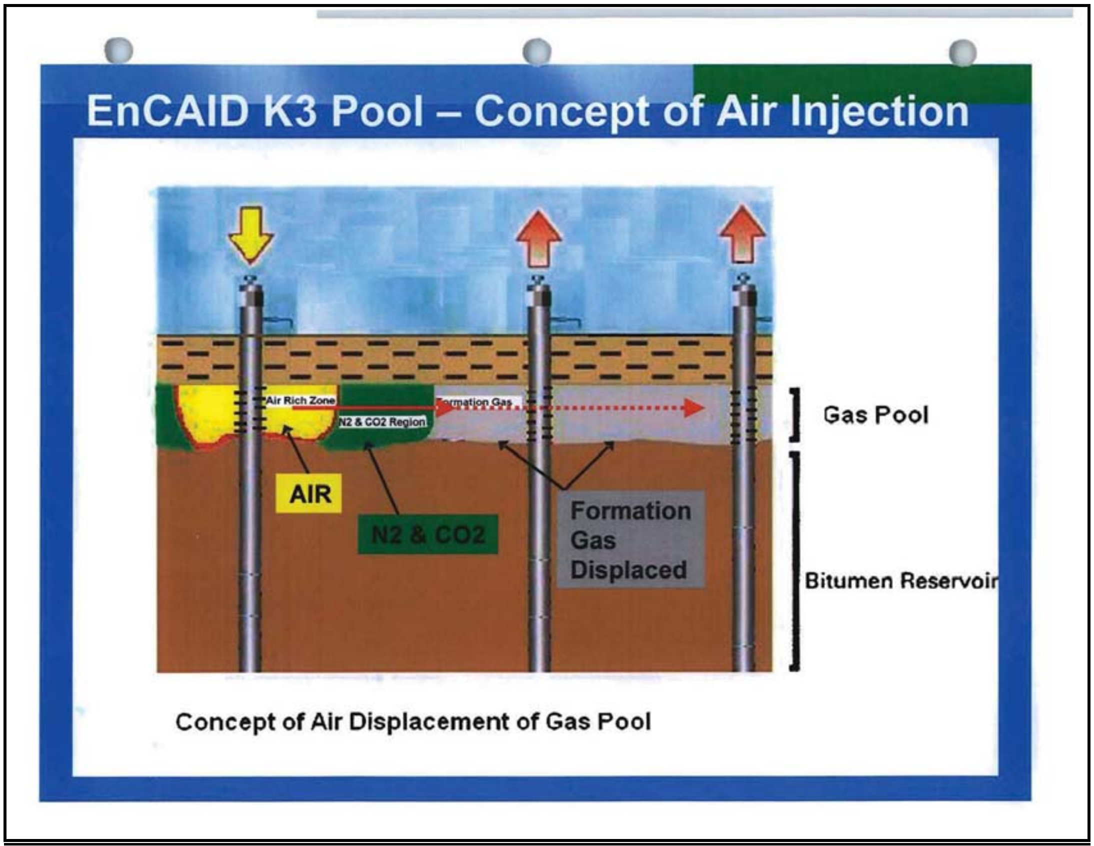
BOILING POINT RANGE (C)	Aromatics		MOLE FRACTION	MASS FRACTION	VOLUME FRACTION
80.0	BENZENE	C6	0.0000	0.0000	0.0000
110.6	TOLUENE	C7	0.0002	0.0001	0.0001
136.2	ETHYLBENZENE	C8	0.0002	0.0001	0.0001
138.4 - 144.4	XYLENES	C8	0.0005	0.0002	0.0002
168.9	1,2,4 TRIMETHYLBENZENE	C9	0.0009	0.0004	0.0004

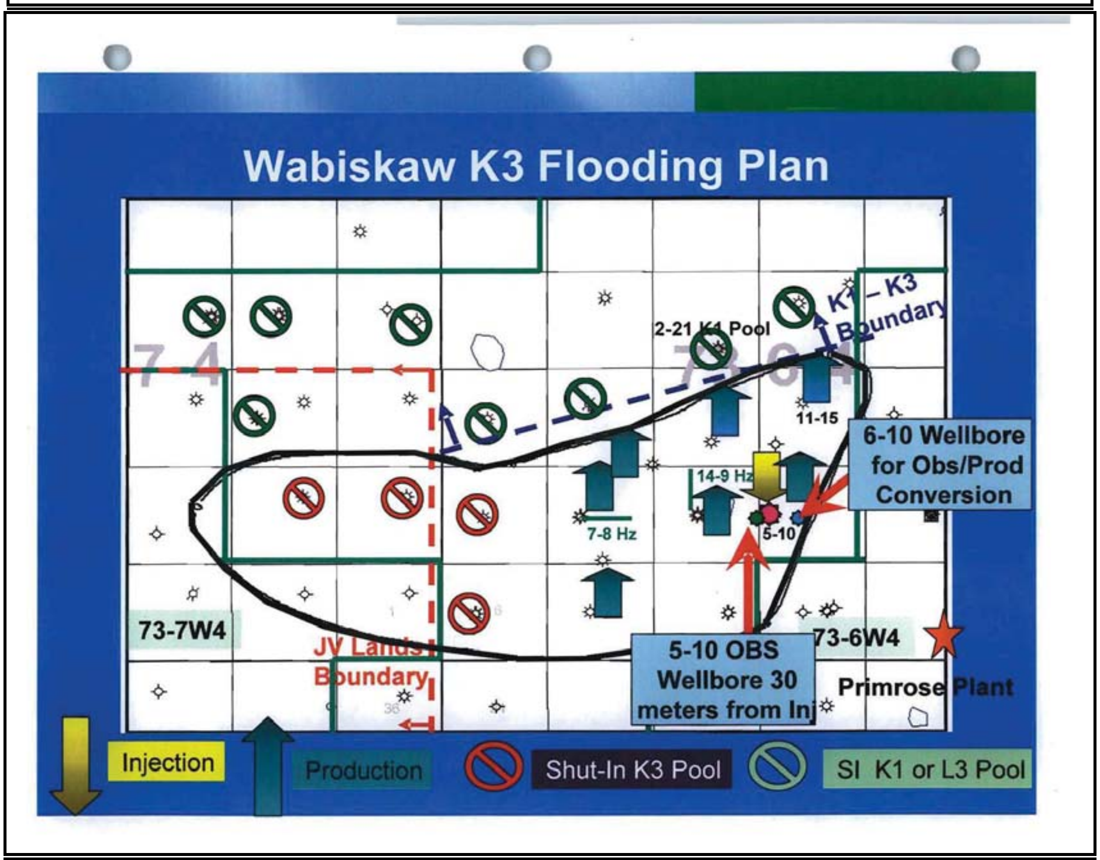
BOILING POINT RANGE (C)	Naphthenes		MOLE FRACTION	MASS FRACTION	VOLUME FRACTION
48.9	CYCLOPENTANE	CC5	0.0000	0.0000	0.0000
72.2	METHYLCYCLOPENTANE	MCC5	0.0000	0.0000	0.0000
81.1	CYCLOHEXANE	CC6	0.0000	0.0000	0.0000
101.1	METHYLCYCLOHEXANE	MCC6	0.0002	0.0001	0.0001

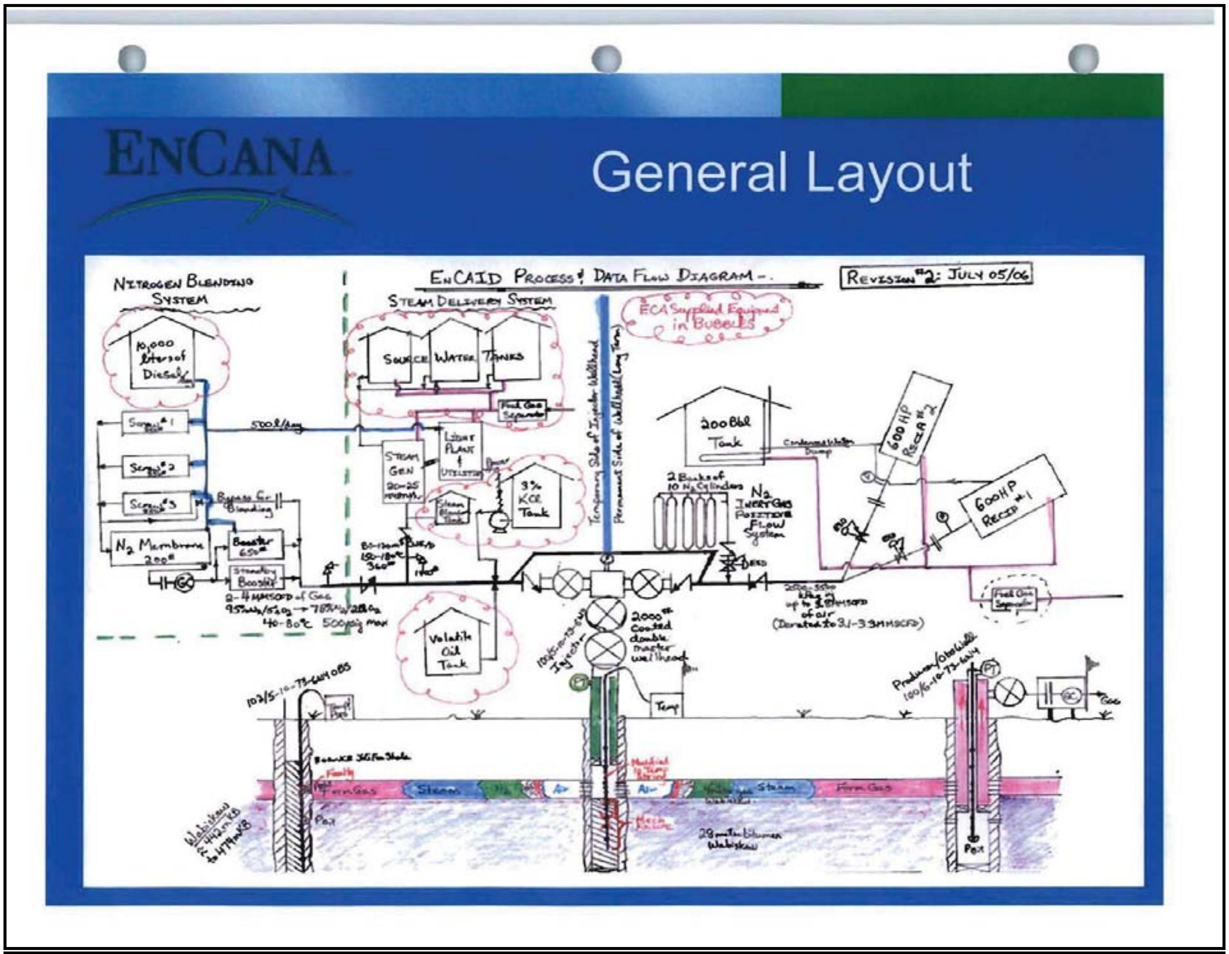
The above hexanes plus values are based upon a measured mass fraction and a calculated mole fraction, and assume a total hydrocarbon recovery from the chromatographic system.

Calgary AB, Ph: (403) 299-2000. Edmonton AB, Ph: (780) 469-0106. Grand Prairie AB, Ph: (780) 539-6500. Red Deer AB, Ph: (403) 346-6645.
Fort St. John BC, Ph: (250) 785-5500. Prince George BC, Ph: (250) 563-6011. Terrace BC, Ph: (250) 615-9288. Mississauga ON, Ph: (905) 501-9998.

Appendix D: Simulation Summary


EnCAID K3 Pool – Concept of Air Injection
Air Rich Zone
N2 & CO2 Region
Formation Gas
Gas Pool
AIR
N2 & CO2
Formation Gas Displaced
Bitumen Reservoir
Concept of Air Displacement of Gas Pool


Wabiskaw K3 Flooding Plan
K1 – K3 Boundary
2-21 K1 Pool
11-15
6-10 Wellbore for Obs/Prod Conversion
14-9 Hz
5-10
7-8 Hz
73-7W4
JV Lands Boundary
5-10 OBS Wellbore 30 meters from Inj
73-6W4
Primrose Plant
Injection
Production
Shut-In K3 Pool
SI K1 or L3 Pool



EnCana
General Layout
EnCAID Process & Data Flow Diagram
Revision #2: July 05/06
Nitrogen Blending System
Steam Delivery System
ECA Supplied Equipment in Bubbles
Source Water Tanks
200 Bbl Tank
600 HP Recip #2
600 HP Recip #1
Volatile Oil Tank

Appendix D: 3D History Match Work

ENCANA

energy for people

EnCAID History Match

October 20th, 2009

Matt Toews, Larry Freeman, Jonah Resnick

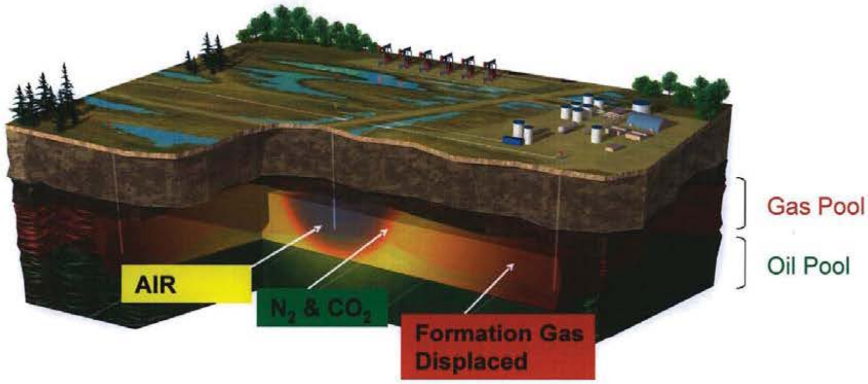
www.encana.com

Outline

- Introduction
- Previous Simulation Work
- Simulation Goals and Issues
- Geological Model
- Kinetic Model
- Results
- Next steps

www.encana.com

Introduction
EnCAID Concept - K3 Pool



- Gas-gas displacement process
- Formation gas is pushed by flue gases

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Introduction
EnCAID Location

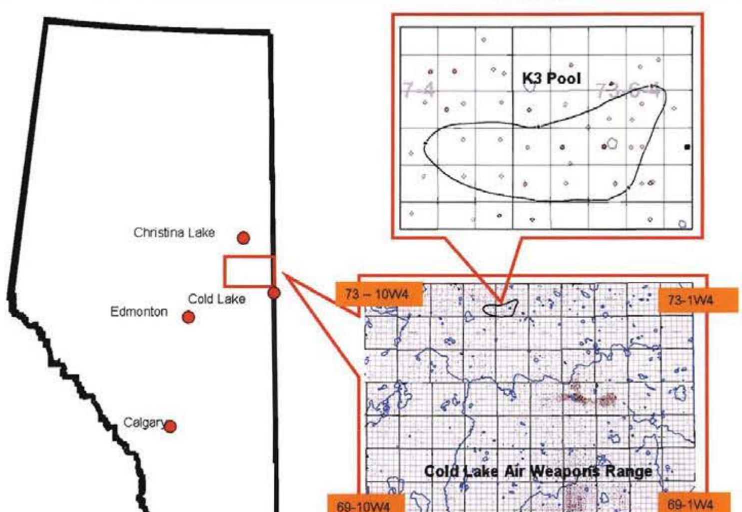
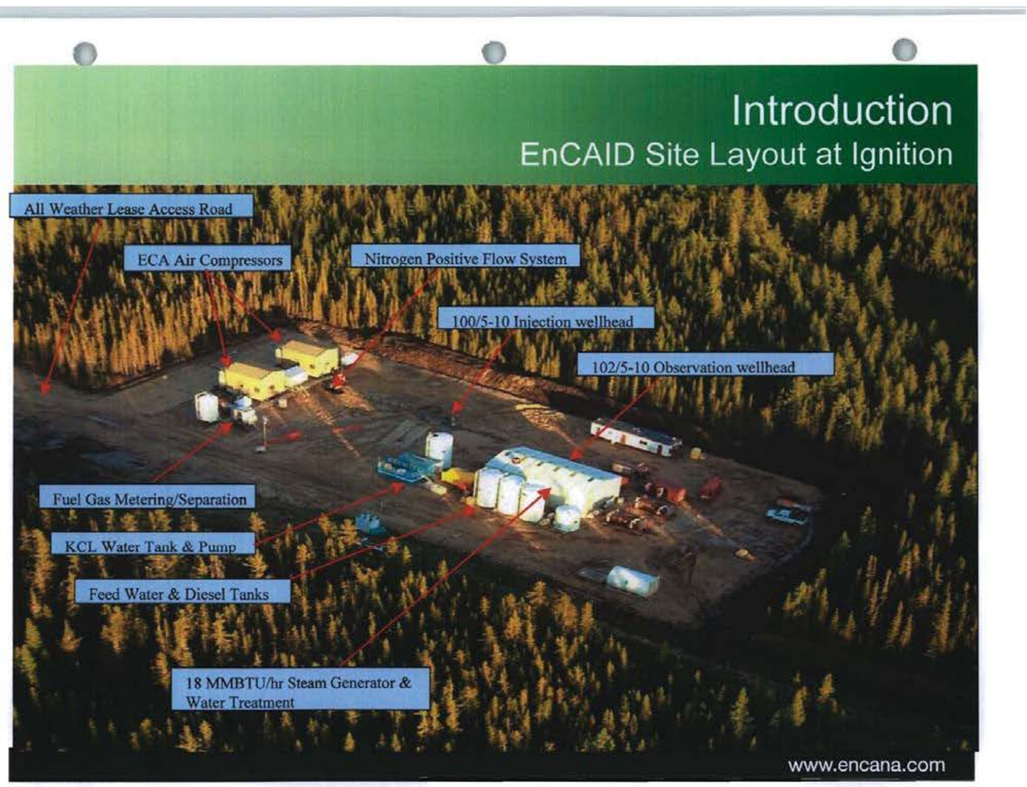
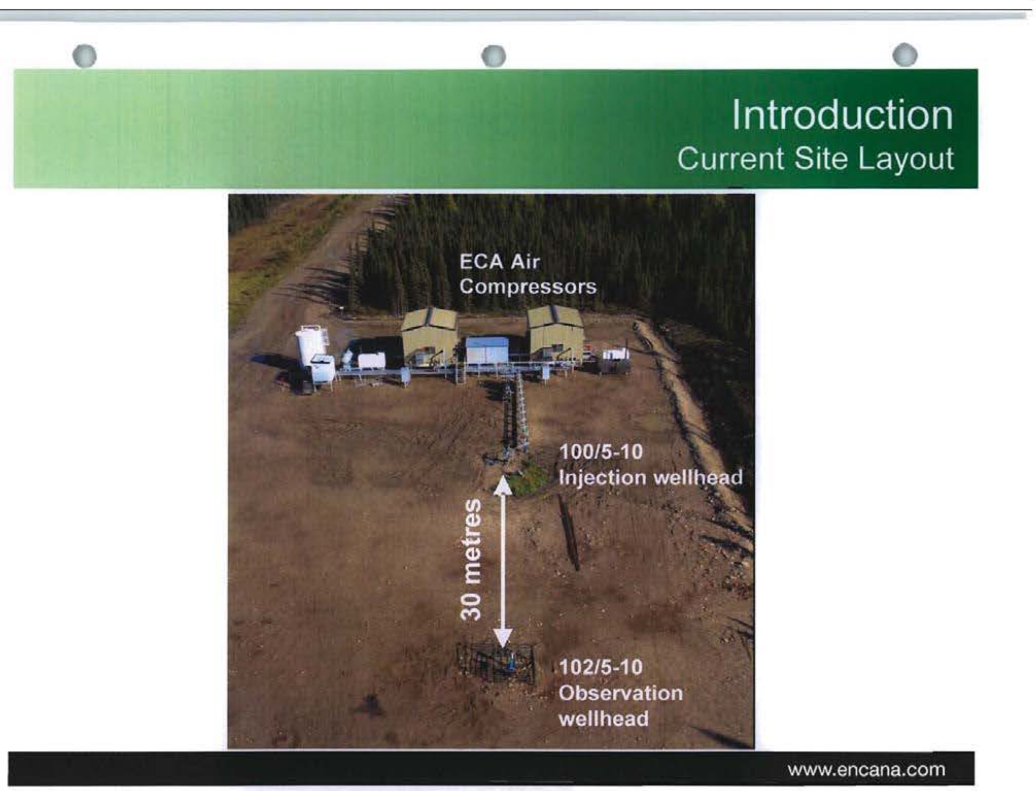


Figure # 1 Location Map

www.encana.com

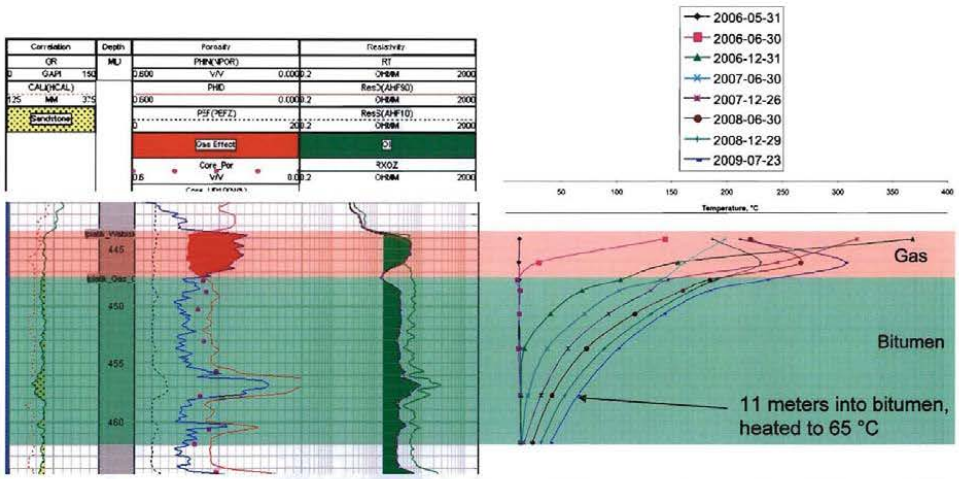

Introduction
EnCAID Site Layout at Ignition
All Weather Lease Access Road
ECA Air Compressors
Nitrogen Positive Flow System
100/5-10 Injection wellhead
102/5-10 Observation wellhead
Fuel Gas Metering/Separation
KCL Water Tank & Pump
Feed Water & Diesel Tanks
18 MMBTU/hr Steam Generator & Water Treatment
www.encana.com


Introduction
Current Site Layout
ECA Air Compressors
100/5-10 Injection wellhead
30 metres
102/5-10 Observation wellhead
www.encana.com

Introduction

EnCAID Temp. Trends from Observation Well

102/-5-10-073-06W4 Observation Well Temperature History



Previous Simulation Work

- Contracted out to KADE Technologies in June 2007
- Attempted to match full field production and combustion zone reactions simultaneously

1
- **Constructed Field Element Model -: Adjust laboratory kinetic rates to field scale.**
- **Quick model to study impact of individual reaction.**

2
- **Constructed model of gas field with all wells represented and layer representing the underlying bitumen resource.**

3
- **Applied local refinement around air injection and observation wells and in the bitumen zone**

4
- **Applied Dynamic Grid Models to speed up model execution**

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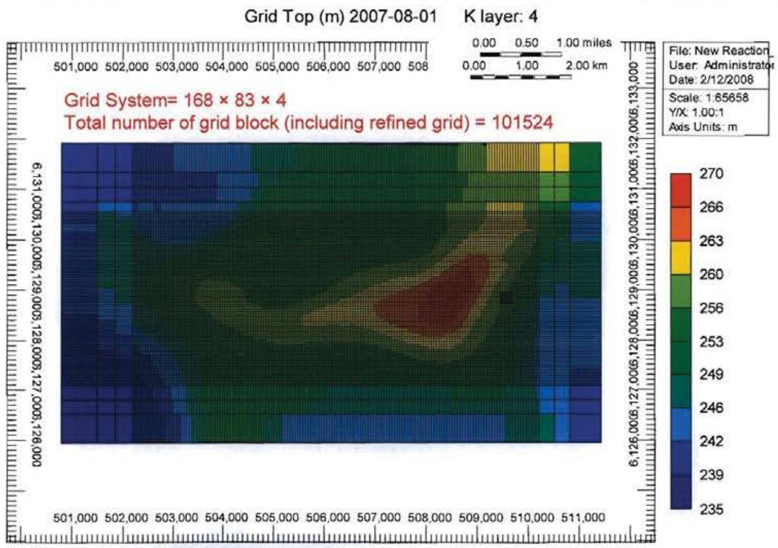
KADE Simulation Model



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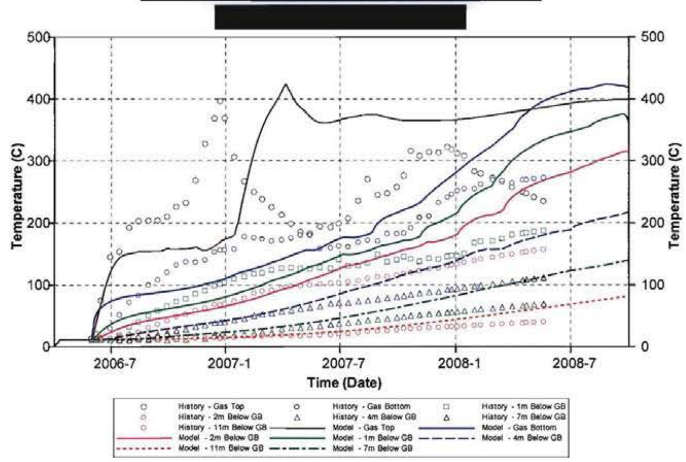
Temperature Match with reduced air rate

[redacted]



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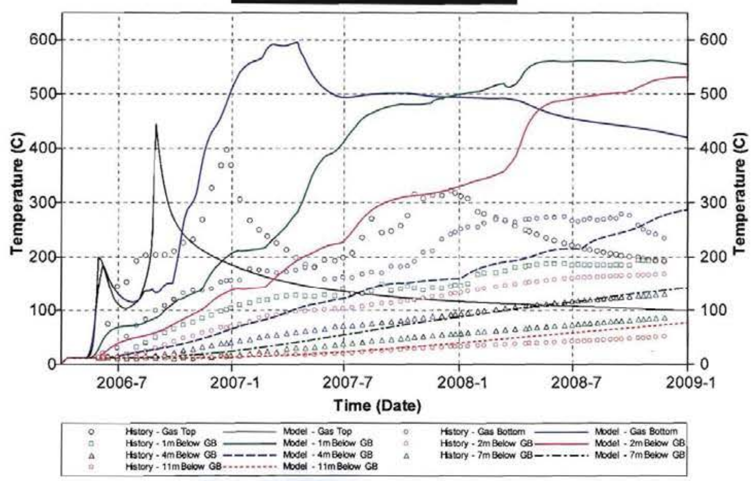
Last Temperature Match

[redacted]



11

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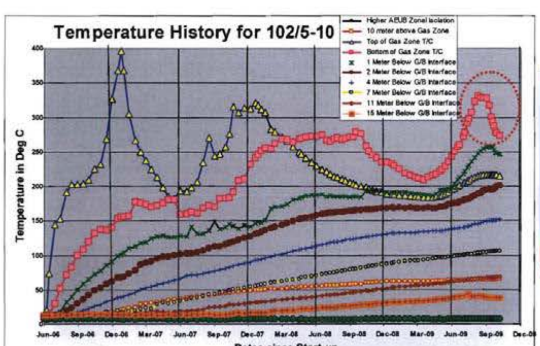
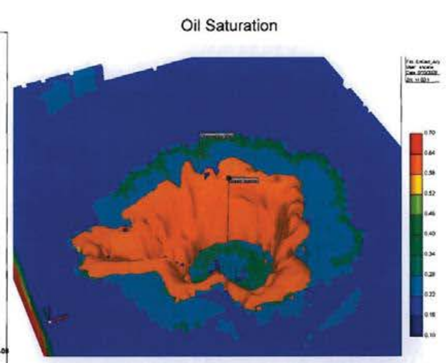
EnCAID Simulation Goals

- **Goals :**
  - **Match speed of the combustion front**
  - **Match temperatures within the gas cap and bitumen zones**
  - Match combustion and formation gas production





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Issues with History Matching

- Combustion front speed – too quick
- Unable to match "double-peak" phenomenon
- Temperatures – too high
- Simulation run-times

Continued burning on top of bitumen requires more air

*Matching temperatures is different from production/ pressure

Changes made with:

- Geological model
- Kinetic model

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Original Geological Model Grid

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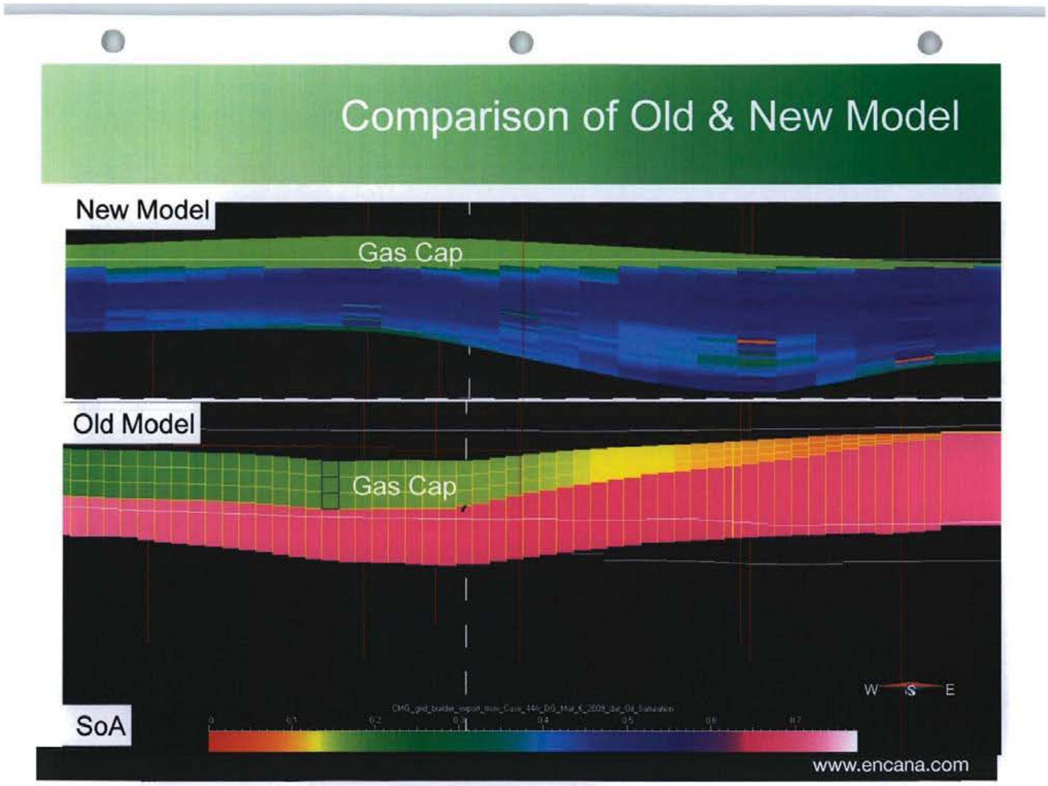
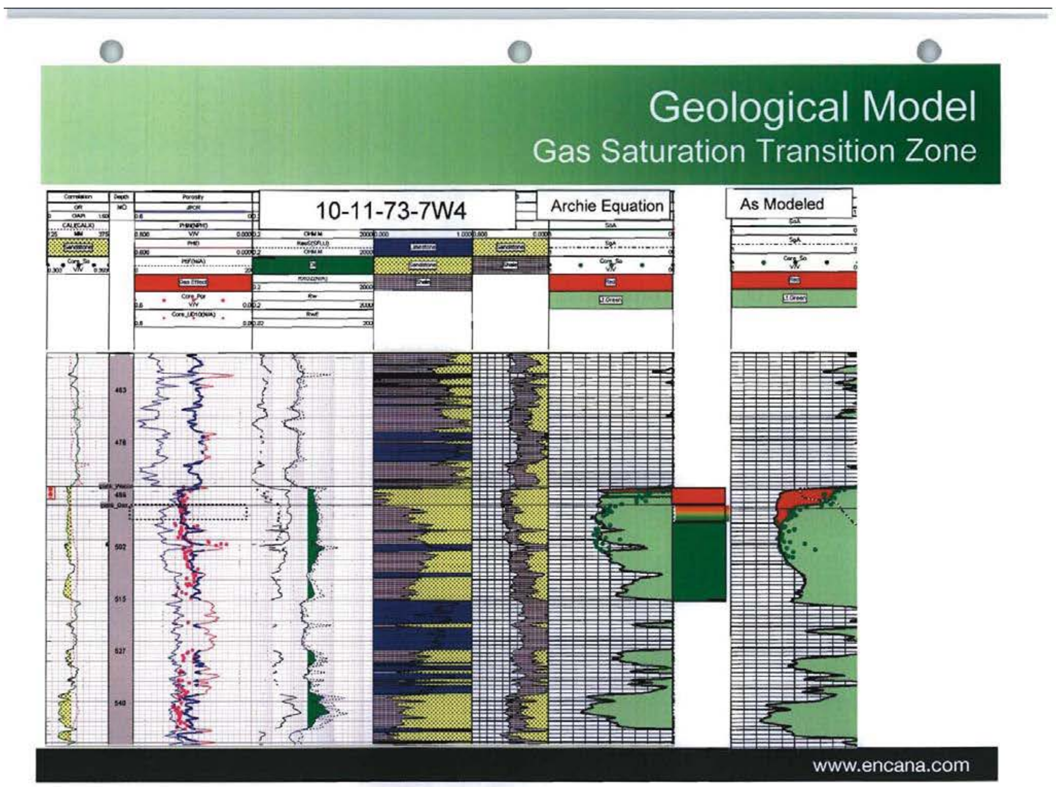
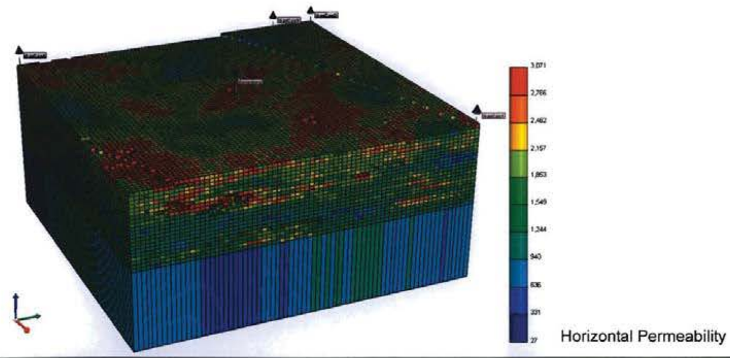

Comparison of Old & New Model
New Model
Gas Cap
Old Model
Gas Cap
SoA
W
S
E
www.encana.com


Geological Model
Gas Saturation Transition Zone
10-11-73-7W4
Archie Equation
As Modeled
www.encana.com

Geological Model
Focused area

- Built using geostatistical approach with an extremely fine grid
- Variograms use all K3 pool data – limited
- Significant uncertainties in large scale heterogeneity (over several sections)
- Relatively consistent over an area the size of the combustion zone (100m radius)



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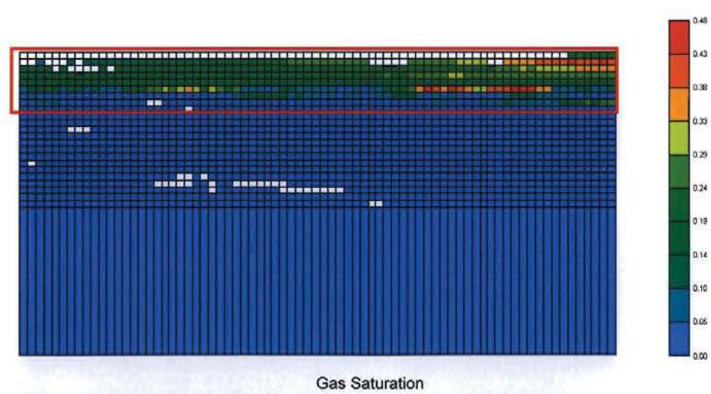
Geological Model
Gas Cap properties

- Upscaled to 2m x 2m x 1m
- 180,000 grid blocks – Gas cap only with 3 meters of bitumen



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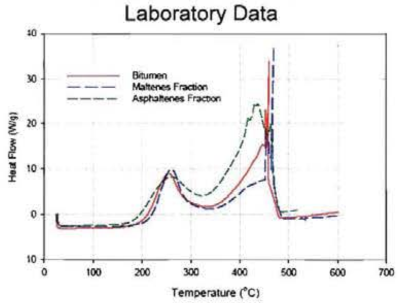
Kinetic Model
Reactions

- **Thermal Cracking**
  - Bond scission reactions
  - Visbreaking and upgrading of the crude
  - Slightly endothermic
- **Low temperature oxidation (LTO)**
  - Additive polymerization reactions that increase oil viscosity and density
  - Exothermic
- **High temperature oxidation (HTO)**
  - Produces carbon oxides and water
  - Coke-like fuel burned
  - Exothermic

Reactions

	Reactions	
1	HO = LO + C	CRACKING REACTIONS
2	$LO = HO + CH_4 + CO_2 + H_2S + C$	CRACKING REACTIONS
3	$LO + O_2 = HO$	LOW TEMPERATURE OXIDATION REACTIONS
4	$HO + O_2 = C$	LOW TEMPERATURE OXIDATION REACTIONS
5	$LO + O_2 = H_2O + CO_2$	HIGH TEMPERATURE OXIDATION REACTIONS
6	$HO + O_2 = H_2O + CO_2$	HIGH TEMPERATURE OXIDATION REACTIONS
7	$O_2 + C = H_2O + CO_2$	HIGH TEMPERATURE OXIDATION REACTIONS
8	$CH_4 + O_2 = H_2O + CO_2$	

Foster Creek Bitumen
Laboratory Data



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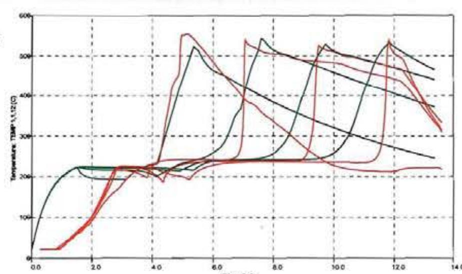
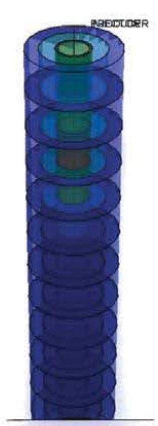
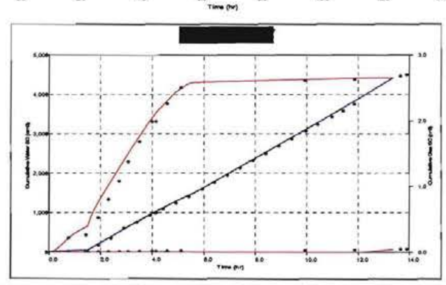
Kinetic Model
History Match Tuning

- **Kinetic parameters are tuned with a combustion tube history match**







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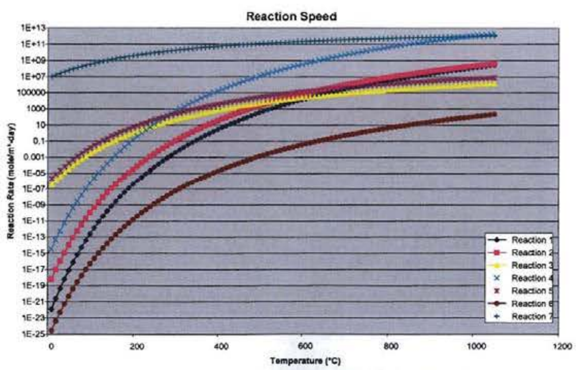
Kinetic Model
Reaction Form

- **STARS uses Arrhenius equations:** $k_r = A_r \exp(-E_r/RT)$
- **"r" is the reaction rate in mole/ m³-day** $r = K_r * (\phi_f \rho_m S_o x)^{[rorder]}$



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Kinetic Model
History Match changes

Problems:

- Temperatures too high
- Front is propagating too quickly

Changes:

- Speed up reactions 3 and 4
- Slowed down reaction 7

Net Effect:

-Less efficient burning

-Trapped oil continues to burn

	Reactions	
1	HO = LO + C	CRACKING REACTIONS
2	LO = HO + CH_4 + CO_2 + H_2S + C	
3	LO + O_2 = HO	LOW TEMPERATURE OXIDATION REACTIONS
4	HO + O_2 = C	
5	LO + O_2 = H_2O + CO_2	HIGH TEMPERATURE OXIDATION REACTIONS
6	HO + O_2 = H_2O + CO_2	
7	O_2 + C = H_2O + CO_2	
8	CH_4 + O_2 = H_2O + CO_2	

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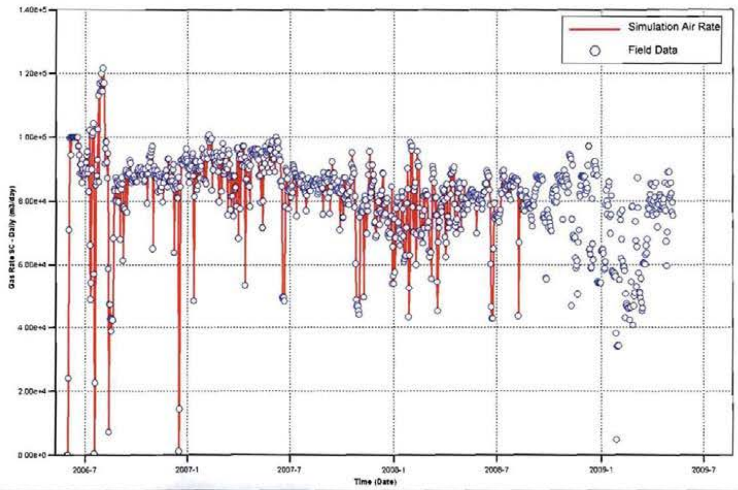
Results
Air Rate Match

- Used Air Injection Rates as Injector primary constraint



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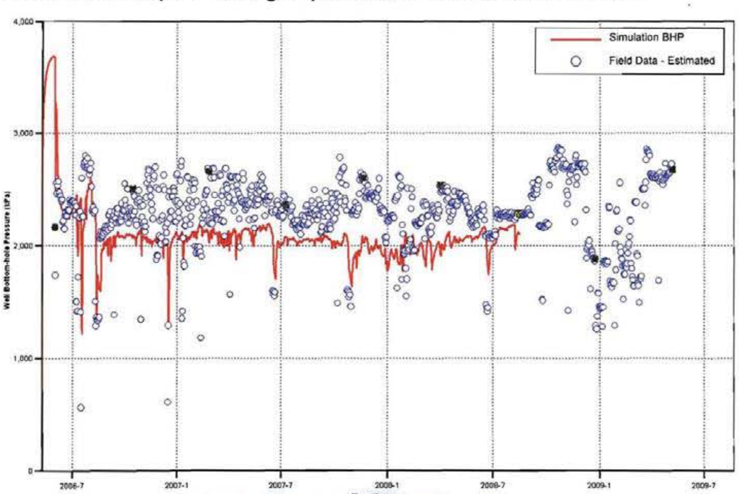
Results
Pressure Match

- Good match on pressure; gas production was not constrained



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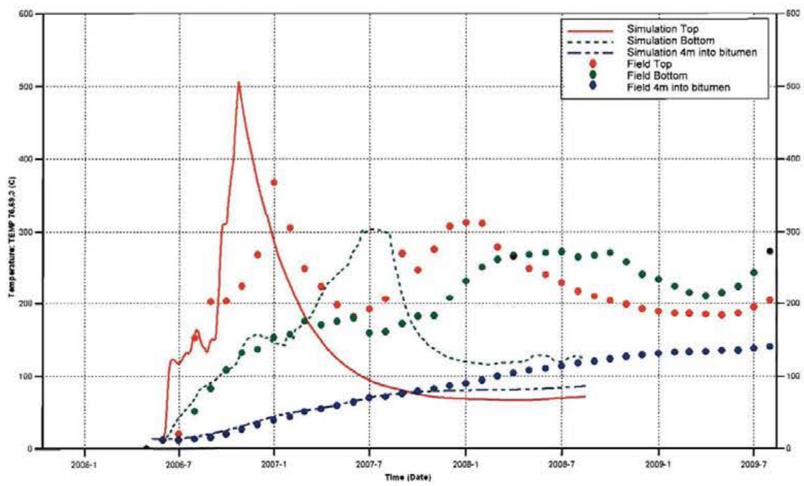
Results
Temperature Match

- Decent match on temperature range and timing, but early drop off



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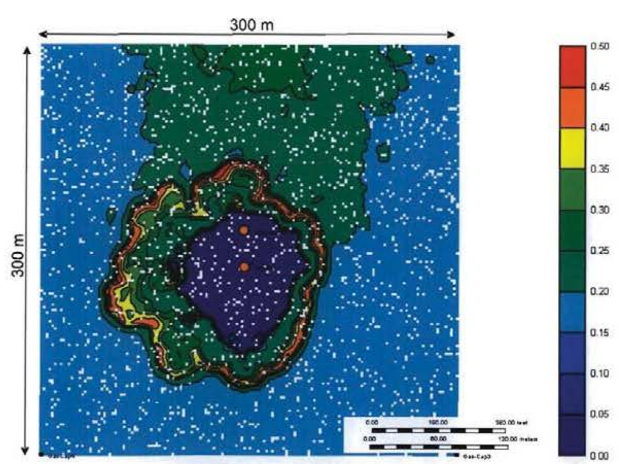
Top view

- Heated area and combustion zone match expected shape



Oil Saturation

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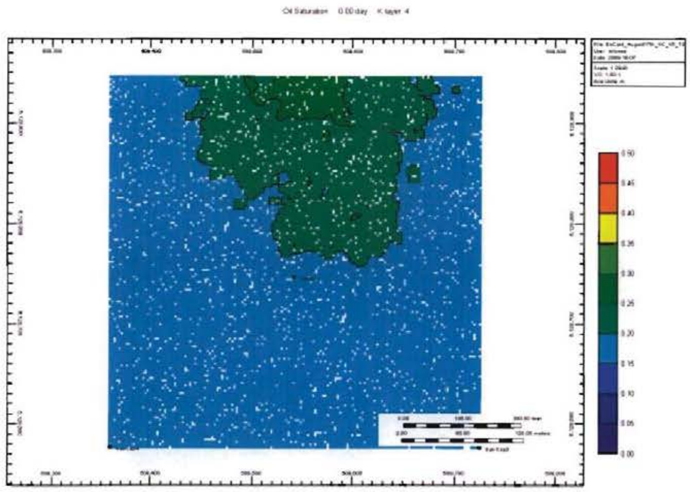
Top View Animation



Oil Saturation

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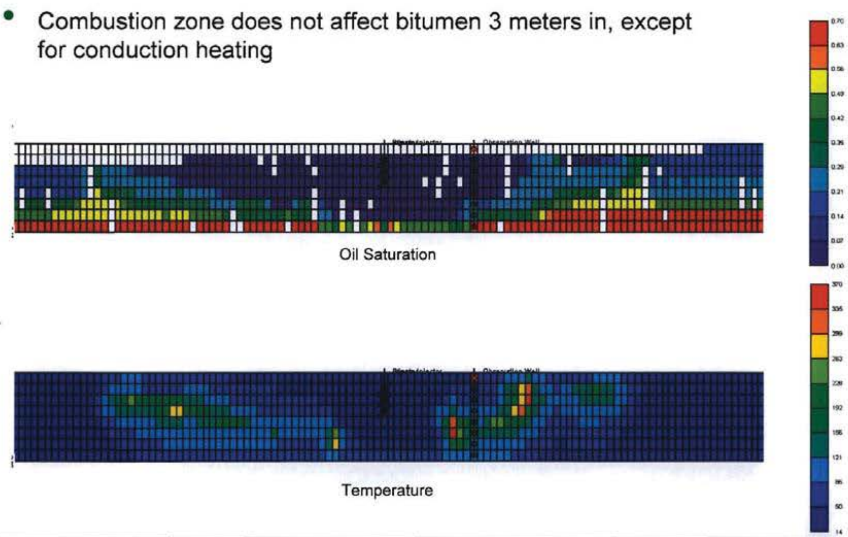
2D cross-section

- Combustion zone does not affect bitumen 3 meters in, except for conduction heating



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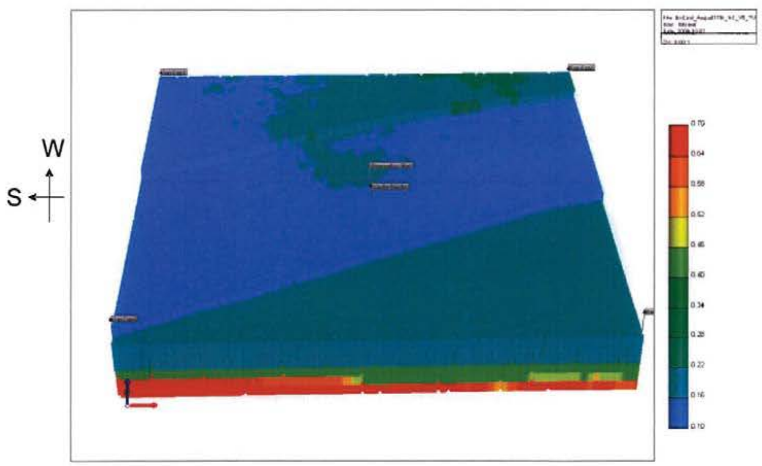
3D Animation



Oil Saturation

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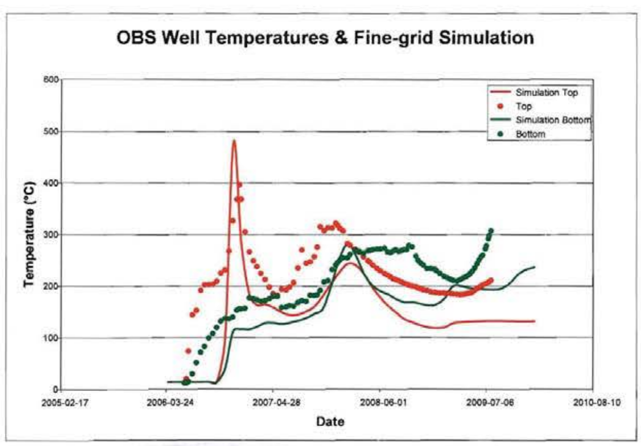
Effect of Grid Block Size

- Can create "double-peak" behaviour with 30 cm grid blocks
- With small grids, can simulate continuous burning or something similar



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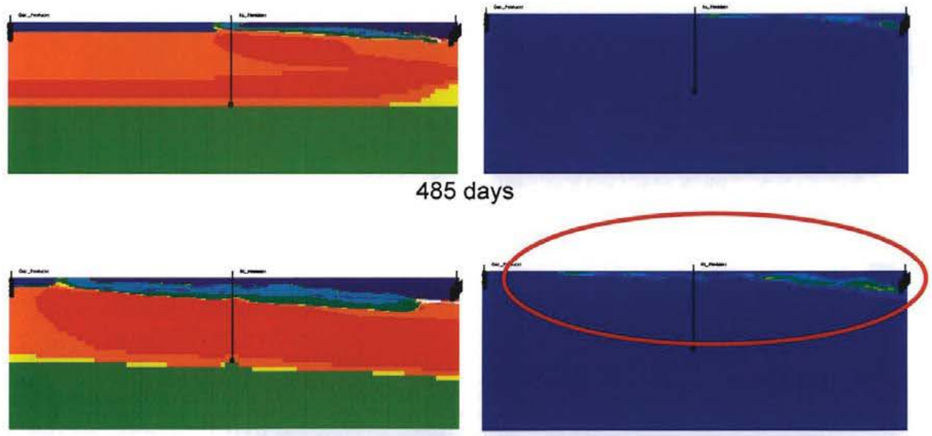
2D Fine Grid Behaviour

Oil Saturation | **Temperature**



485 days

805 days

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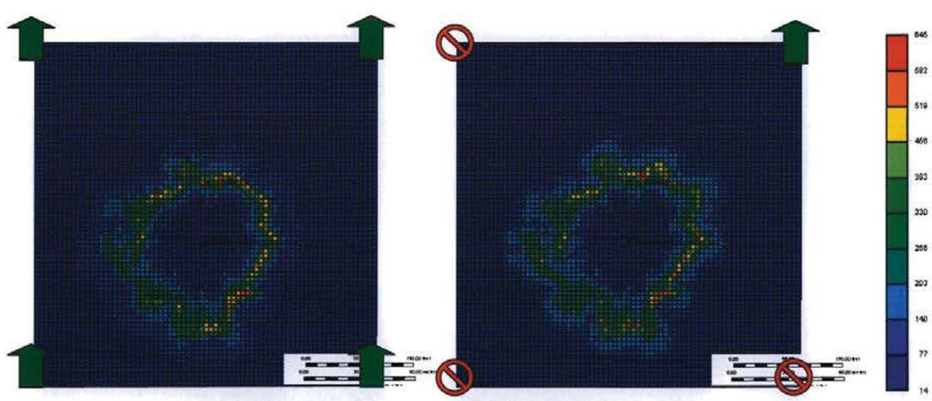
Effect of Gas Production

- Combustion zone largely controlled by fluid saturations and geology



Temperature – 175 days

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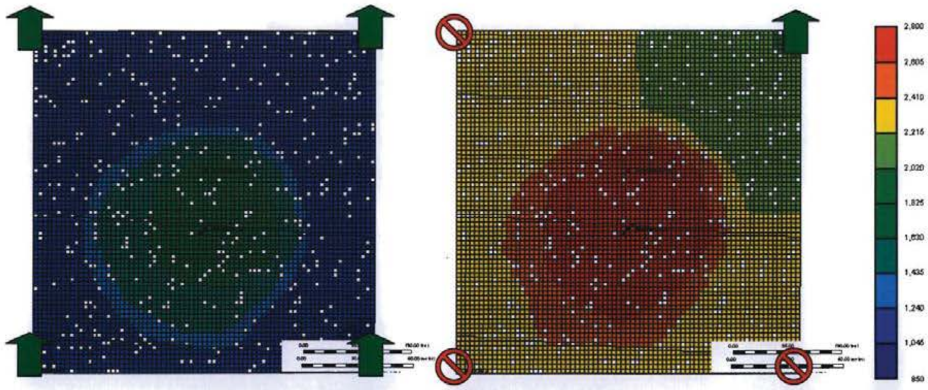
Why no "skewness"?

- Large pressure-drop across oil/water bank
- Fluid bank acts as a "Limited Entry Perforation"
- Constrained model has higher overall pressure*



Pressure – 175 days

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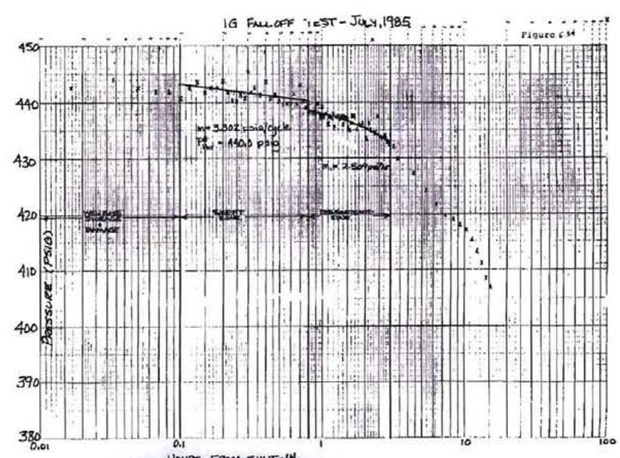
Pelican Lake Fall-off Test

- Fall-off test performed on 7-spot air injection pattern in July 1985
- Confirms existence of a high permeability zone -> low permeability zone



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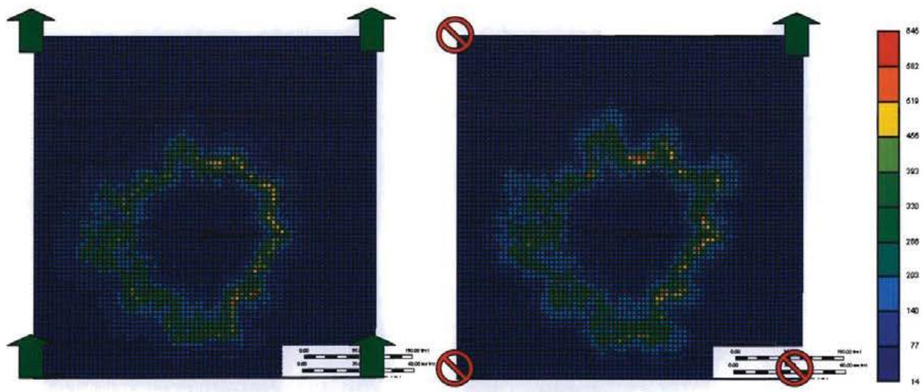
Eventual impact of lopsided gas production

- When the combustion front feels the pool edge, the burned zone will begin to change shape



Temperature – 280 days

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Next Steps

- Decrease run-times – make the model practical
  - Simplify kinetics
- Match full field gas production and flue gas movement
  - Field model – decoupled from reactions

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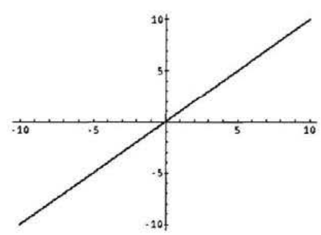
Simplify Kinetics

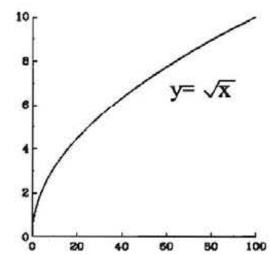
- The major contributor to poor numerical performance is non-linear reaction orders.

$$r = K_r * (\phi_f \rho_m S_o x)^{[rorder]}$$

Reaction #3 order: 0.4246

Reaction #4 order: 4.7627





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Simplify Kinetics

Short of rebuilding kinetic model from scratch, can use empirical method:

- Estimate parameters for Reaction #3 such that it gives similar kinetic performance
- Perform sensitivity runs to determine effect on final result
- Should have a better working model within a few weeks

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Field Model

- Determine model size and any gas "spill-over"
- Inject flue gases into big model to simulate gas-gas displacement
  - No need for reactions
- Will take ~1 month to build a competent geo-model
- Another 2 months to match historical gas production, forecast extra reserves, etc.

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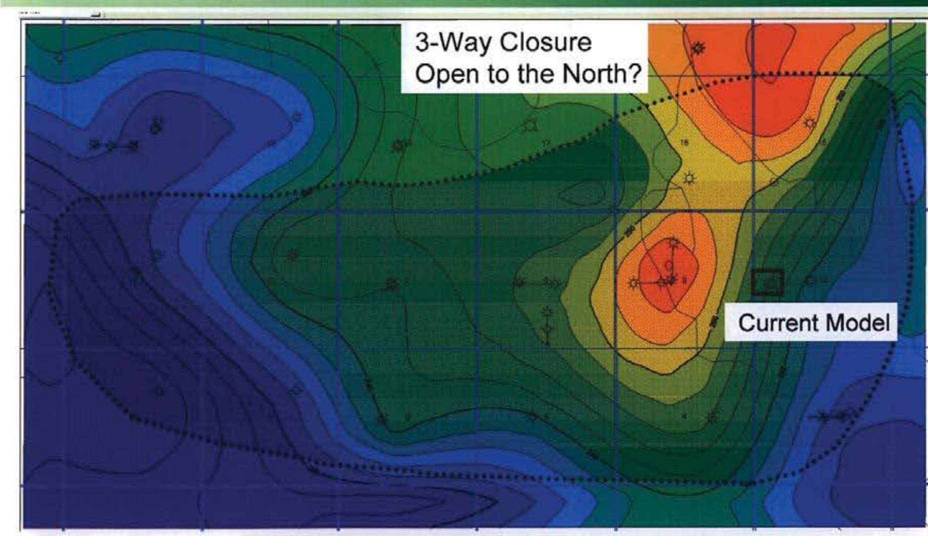
Match Field gas production
Structure on Top of Wabiscaw



EnCana's Current Definition of the K3 Pool

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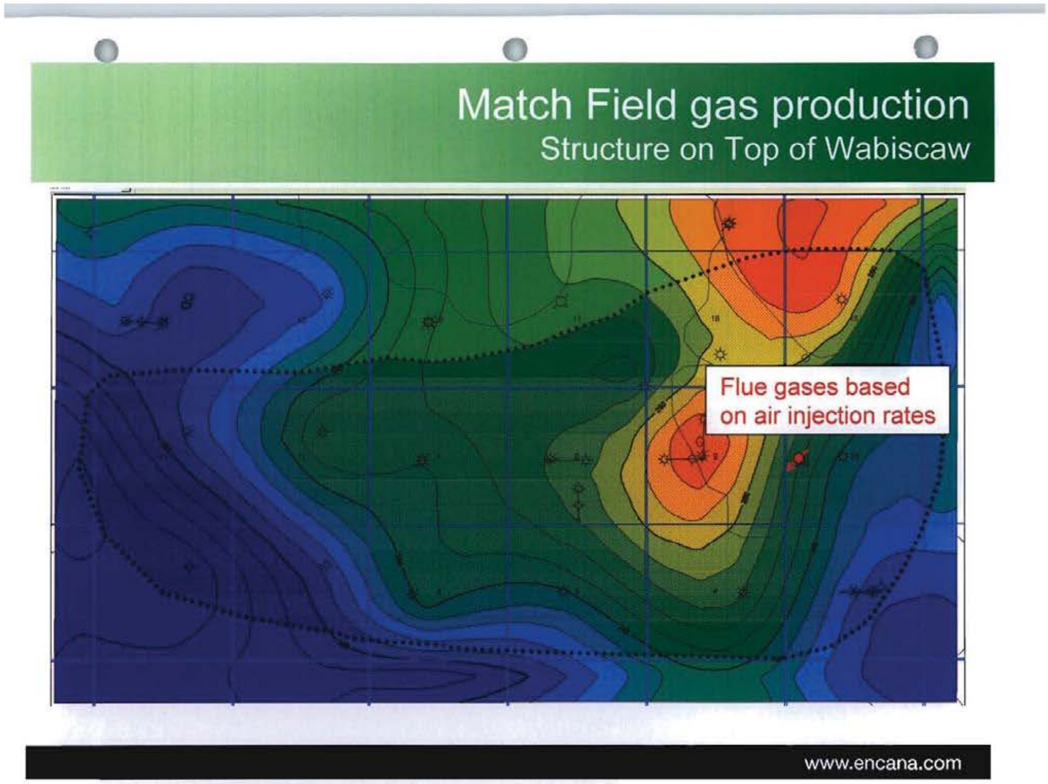

Match Field gas production
Structure on Top of Wabiscaw
Flue gases based
on air injection rates
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Appendix D: Gas Sweep

KADE
TECHNOLOGIES INC.
PETROLEUM CONSULTANTS

EnCAID
Gas Recovery Factor Simulation Cases

By Dr. Kenny O. Adegbesan PhD, P.Eng

KADE Technologies Inc.
Oct 31, 2007

2008-07-25 1

EnCAID Simulation Cases Description

Cases 1

- Operations in EnCana's Lease
    - Boundary wells: 1-17-73R6, 2-16-73R6, 11-15-73R6
    - Inner Wells: 6-5-73R6, 6-6-73R6, 6-7-73R6, 7-8-73R6
    - Injection Wells: 5-10-73R6
- Normal boundary well rate
- Injection rate : 3.3MMSCF/D (After July,2007)

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EnCAID Simulation Cases Description

Cases 2

- Operations in EnCana's Lease
    - Boundary wells: 1-17-73R6, 2-16-73R6, 11-15-73R6
    - Inner Wells: 6-5-73R6, 6-6-73R6, 6-7-73R6, 7-8-73R6
    - Injection Wells: 5-10-73R6
- Set boundary well half rate from September 1, 2007
- Injection rate : 3.3MMSCF/D (After July,2007)

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EnCAID Simulation Results Summary

Case #	Forecast Period	Simulation Results						
		Period Cumulative			Recovery Factor			
		Inje	Prod		Period Air Inje		Prior-air Inje	Total
			Total Gas	CH_4	Total Gas	CH_4	CH_4	CH_4
		(E6 m3)	(E6 m3)	(E6 m3)	%	%	%	%
Case 1	Jun,2006--Dec,2030	653.5	594.8	239.5	59.34	23.90	76.94	101.84
Case 2	Jun,2006--Dec,2030	455.5	414.9	226.1	41.39	22.56	76.94	99.50

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EnCAID Simulation Results Summary

case #	Forecast Period	Simulation Results						
		Period Cumulative			Recovery Factor			
		Inje	Production		Period Air Inje		Prior-air Inje	Total
			Total Gas	CH_4	Total Gas	CH_4	CH_4	CH_4
		BCF	BCF	BCF	%	%	%	%
Case 1	Jun,2006--Dec,2030	23.1	21.0	8.6	59.34	23.90	76.94	101.84
Case 2	Jun,2006--Dec,2030	16.1	14.7	8.0	41.39	22.56	76.94	99.50

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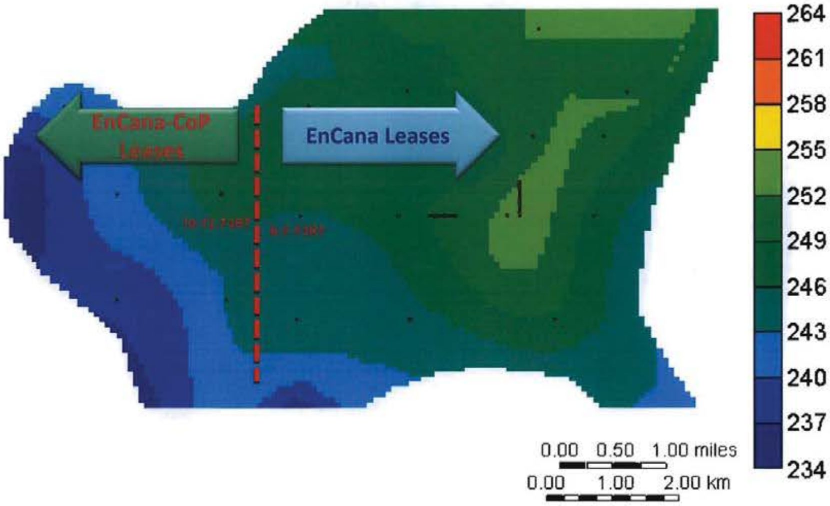
Case 1 & 2 Well Map



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Case 1

EnCana Lease with Normal Rate

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Case1: EnCana Lease with Normal Rate

Summary:

- Keep Inj/Prod Ratio =1.1 after July, 2007
- Forecast period: June 2, 2006 to 2030-12-31
- Shut in well:

Name:	07-08-73R6	06-05-73R6
Date:	2012-09-01	2022-07-01
N2(%):	60.60	60.09

- Open Well:

Name:	06-06-73R6	06-07-73R6
Date:	2012-09-01	2012-09-01

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Case1: EnCana Lease with Normal Rate

Period Forecast Result

- Total gas production:
  21.0 (BCF)
- Gas CH4 Production:
  8.6 (BCF)
- Total gas injection:
  23.1 (BCF)
- Total gas recovery factory:
  59.34%
- Gas CH4 recovery factory:
  23.90 %

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Case 1: EnCana Lease with Normal Rate

Restart #	Restart Name	Case Description: Production Wells: Boundry	Production Wells: Inner	Injection Wells	Adjuest Wells: Shut In: Name	Shut In: Date	Shut In: N2 (%)	Adjuest Wells: Open
Restart 0	Case01_A_1p1to1nj_Aug_2	01-17-73R6 02-16-73R6 11-15-73R6	07-08-73R6 06-05-73R6	05-10-73R6				
Restart 1	Case_01B_1p1to1nj_SI07-8_OPN06-6 & 06-7_Aug_3	01-17-73R6 02-16-73R6 11-15-73R6	06-05-73R6 06-06-73R6 06-07-73R6	05-10-73R6	07-08-73R6	2012-09-01	60.6	06-06-73R6 06-07-73R6
Restart 2	Case_01C_1p1to1nj_SI07-8_06-5_OPN06-6_06-7_Rst2_Aug_5	01-17-73R6 02-16-73R6 11-15-73R6	06-06-73R6 06-07-73R6	05-10-73R6	06-05-73R6	2022-07-01	60.09	

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Case 1: EnCana Lease with Normal Rate

Restart #	Restart Name	Gas Rate: Inje (E3 m3/d)	Gas Rate: Prod (E3 m3/d)	Gas Rate: Inje/Prod Ratio	Period Production & Injection: Total Inje (E6 m3)	Total Production: Gas (E6 m3)	Total Production: CH4 (E6 m3)	Recovery Factor: Gas (%)	Recovery Factor: CH4 (%)	Recovery Factor: Prior Air Inje CH4 (%)	Recovery Factor: Total CH4 (%)
Restart 0	Case01_A_1p1to1nj_Aug_2	95.0	86.3	1.10							
Restart 1	Case_01B_1p1to1nj_SI07-8_OPN06-6 & 06-7_Aug_3	70.1	63.8	1.10							
Restart 2	Case_01C_1p1to1nj_SI07-8_06-5_OPN06-6_06-7_Rst2_Aug_5	59.2	53.8	1.10	653.5	594.8	239.5	59.34	23.90	76.94	101.84

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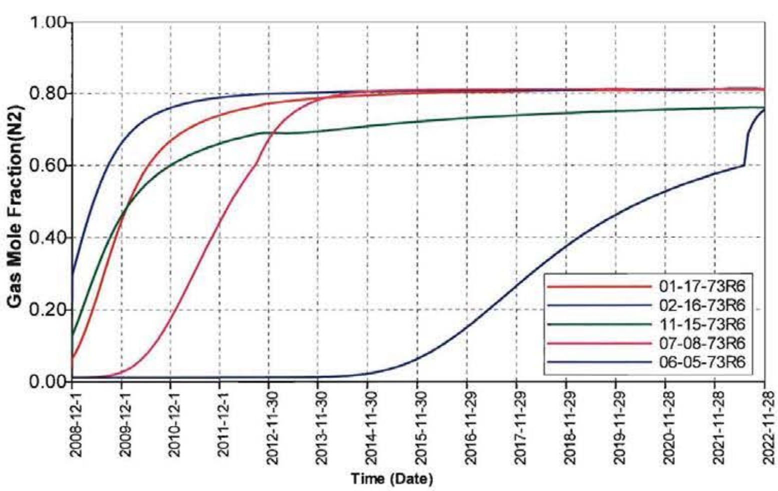
Case 1: EnCana Lease with Normal Rate

Restart #	Restart Name	Gas Rate Inje (MSCF/d)	Gas Rate Prod (MSCF/d)	Inje/Prod Ratio	Period Production & Injection: Total Inje (BCF)	Total Prod Gas (BCF)	Total Prod CH4 (BCF)	Recovery Factor Gas (%)	Recovery Factor CH4 (%)	Recovery Factor: Prior Air Inje CH4 (%)	Recovery Factor: total CH4 (%)
Restart 0	Case01_A_1p1to1nj_Aug_2	3354.7	3049.8	1.10							
Restart 1	Case_01B_1p1to1nj_SI07-8_OPN06-6 & 06-7_Aug_3	2477.2	2251.9	1.10							
Restart 2	Case_01C_1p1to1nj_SI07-8_06-5_OPN06-6_06-7_Rst2_Aug_5	2091.2	1901.4	1.10	23.08	21.01	8.60	59.34	23.90	76.94	101.84

Restart

2008-07-25 12

Case 1: EnCana Lease with Normal Rate



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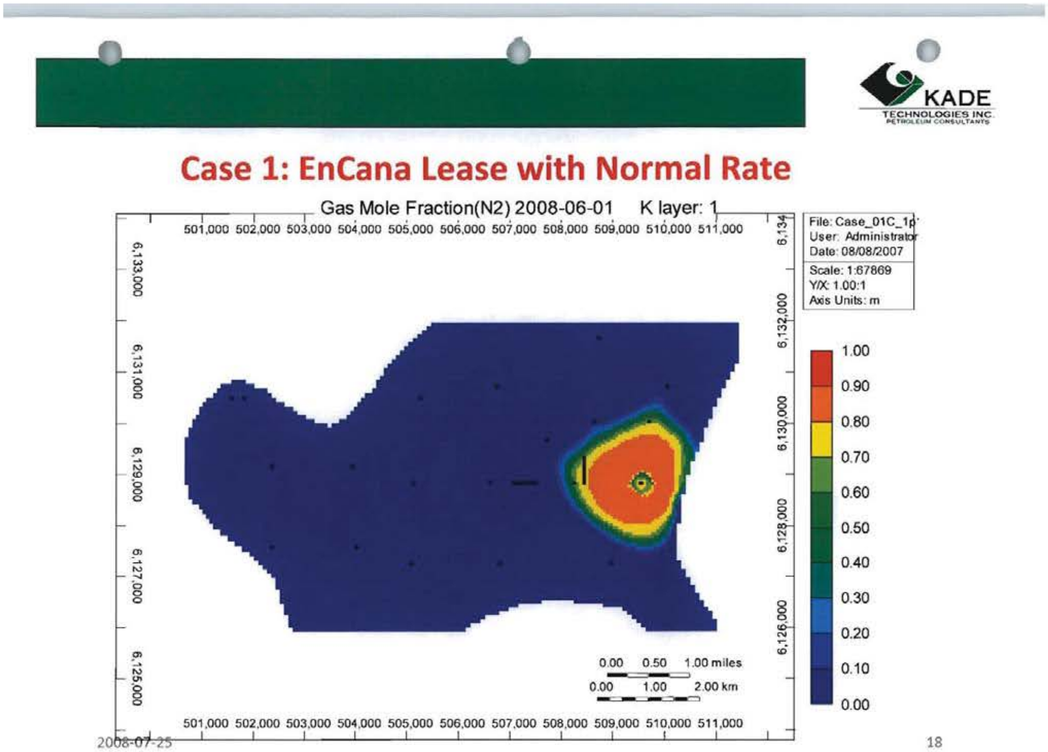
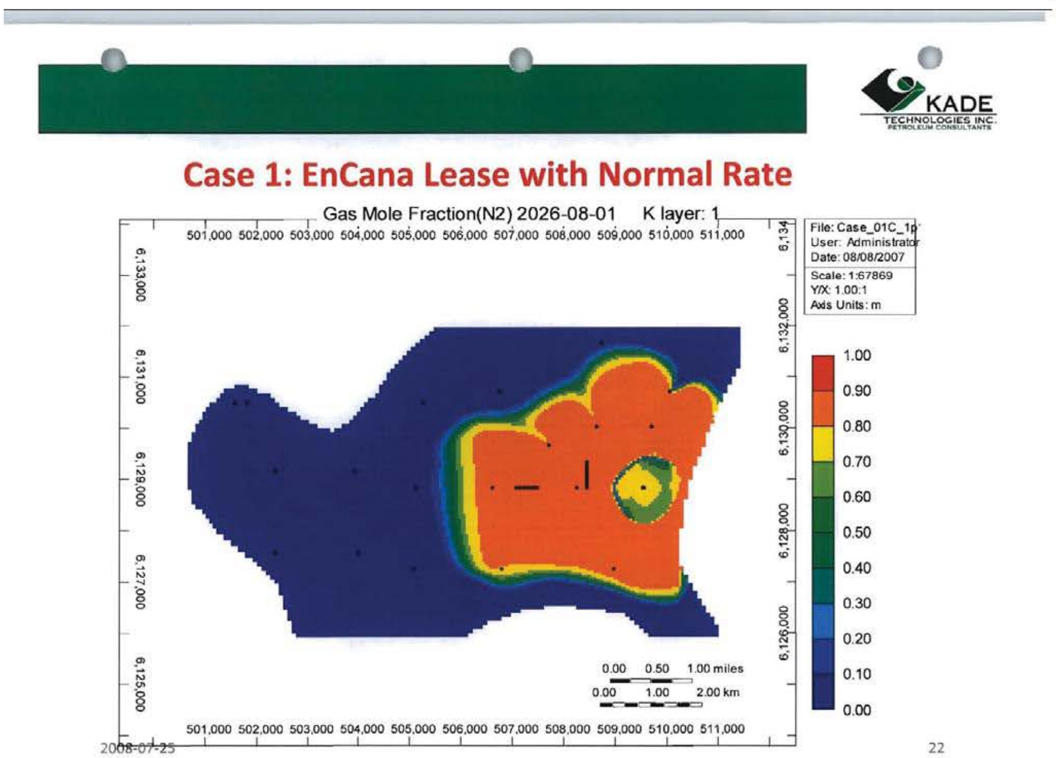
Case 1: Cumulative Gas Production / Injection vs Time

2008-07-25 14

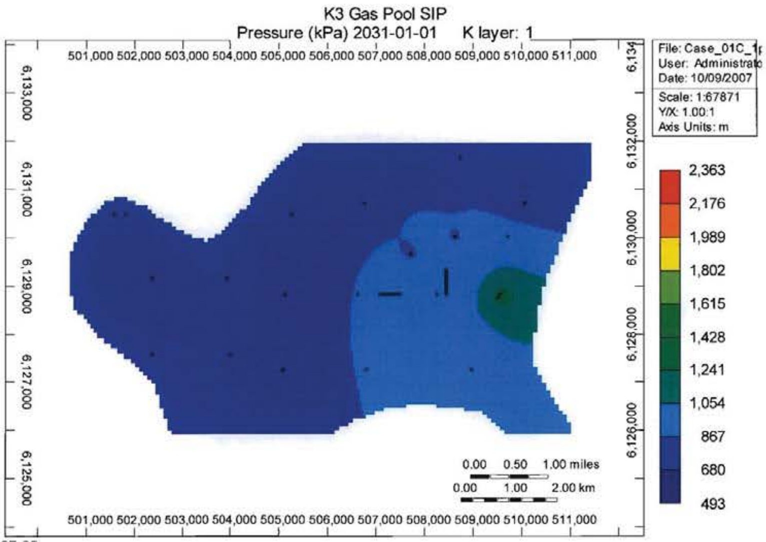
Case 1: EnCana Lease with Normal Rate

2008-07-25 16


KADE
TECHNOLOGIES INC.
Case 1: EnCana Lease with Normal Rate
Gas Mole Fraction(N2) 2008-06-01 K layer: 1
File: Case_01C_1p
User: Administrator
Date: 08/08/2007
Scale: 1:67869
Y/X: 1.00:1
Axis Units: m
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0.00 0.50 1.00 miles
0.00 1.00 2.00 km
501,000 502,000 503,000 504,000 505,000 506,000 507,000 508,000 509,000 510,000 511,000
6,133,000 6,131,000 6,129,000 6,127,000 6,125,000
6,134 6,132,000 6,130,000 6,128,000 6,126,000
2008-07-25
18


KADE
TECHNOLOGIES INC.
Case 1: EnCana Lease with Normal Rate
Gas Mole Fraction(N2) 2026-08-01 K layer: 1
File: Case_01C_1p
User: Administrator
Date: 08/08/2007
Scale: 1:67869
Y/X: 1.00:1
Axis Units: m
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0.00 0.50 1.00 miles
0.00 1.00 2.00 km
501,000 502,000 503,000 504,000 505,000 506,000 507,000 508,000 509,000 510,000 511,000
6,133,000 6,131,000 6,129,000 6,127,000 6,125,000
6,134 6,132,000 6,130,000 6,128,000 6,126,000
2008-07-25
22

Case 1: EnCana Lease with Normal Rate



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Case 2

EnCana Lease

with Boundary Well Half Rate

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Case 2: EnCana Lease with Boundary Well half Rate

Summary:

- Keep Inj/Prod Ratio =1.1 after July, 2007
- Forecast period: Jun 2,2006 to 2030-12-31
- Shut in well:
  - Name: 07-08-73R6 06-05-73R6
  - Date: 2013-03-01 2024-09-01
  - N2(%): 59.67 60.03
- Open Well:
  - Name: 06-06-73R6 06-07-73R6
  - Date: 2013-03-01 2013-03-01

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Case 2: EnCana Lease with Boundary Well half Rate

Period Forecast Result

- Total gas production:
  14.7 (BCF)
- Gas CH4 production:
  8.0 (BCF)
- Total gas injection:
  16.1 (BCF)
- Total gas recovery factory:
  41.39 %
- Gas CH4 recovery factory:
  22.56 %

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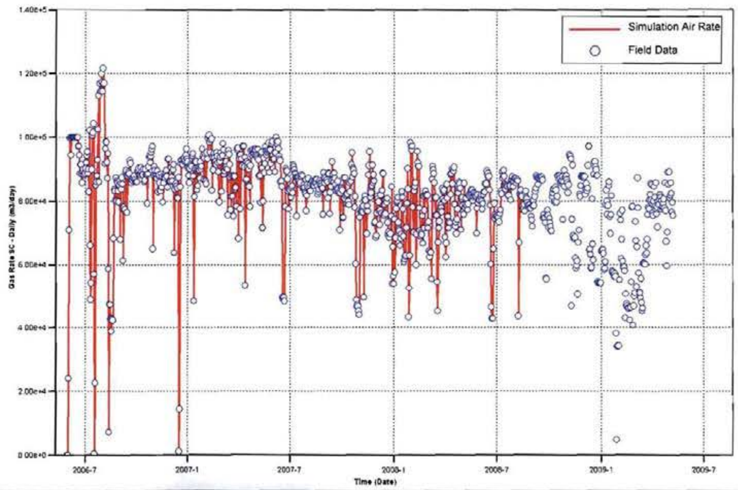
Results
Air Rate Match

- Used Air Injection Rates as Injector primary constraint



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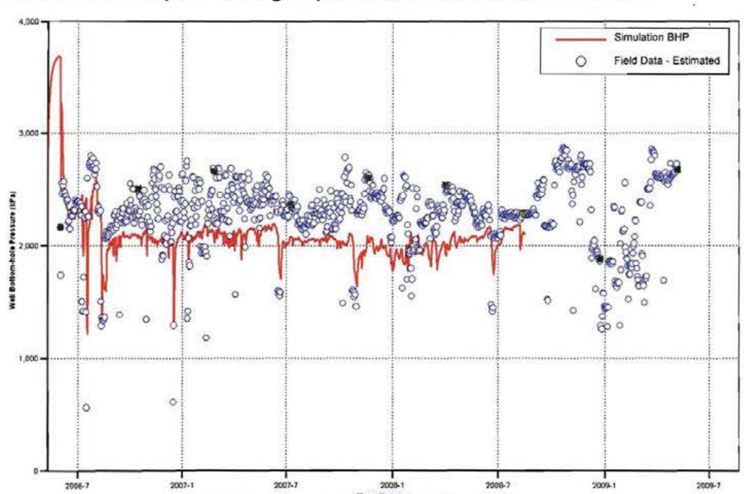
Results
Pressure Match

- Good match on pressure; gas production was not constrained



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Case 2: EnCana Lease with Boundary Well half Rate

Restart #	Restart Name	Gas Rate Inje (MSCF/d)	Gas Rate Prod (MSCF/d)	Inje/Prod Ratio	Period Production & Injection: Total Inje (BCF)	Total Prod Gas (BCF)	Total Prod CH4 (BCF)	Recovery Factor Gas (%)	Recovery Factor CH4 (%)	Recovery Factor: Prior Air Inje CH4 (%)	total CH4 (%)
Restart 0	Case01_A_1p1to1nj_Boundry_Well_Half_Rate_on Sep1 2007_Aug_2	2473.77	2248.93	1.10							
Restart 1	Case01_B_1p1to1nj_Boundry_Well_Half_Rate_on Sep1 2007_SI_07-08_OPN_06-06 & 06-07_Aug_4	1596.28	1451.15	1.10							
Restart 2	Case01_C_1p1to1nj_Boundry_Well_Half_Rate_on Sep1 2007_SI_07-08 & 06-05_OPN_06-06 & 06-07_Aug_6	1210.64	1100.55	1.10	16.01	14.70	8.00	41.39	22.56	76.94	99.50

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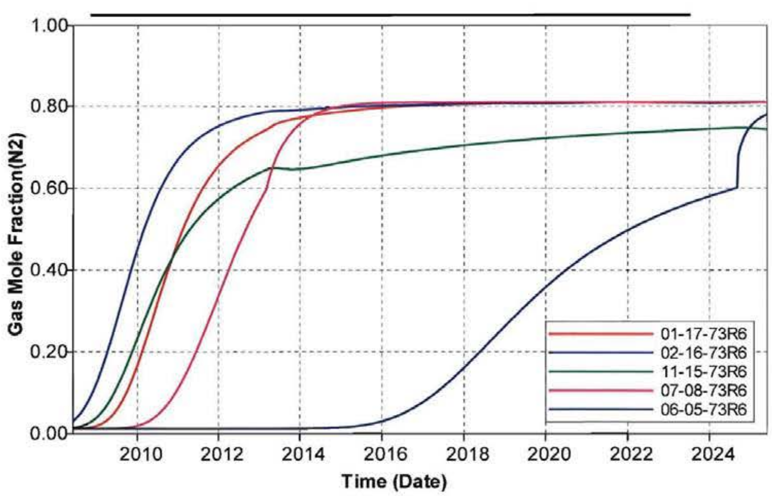
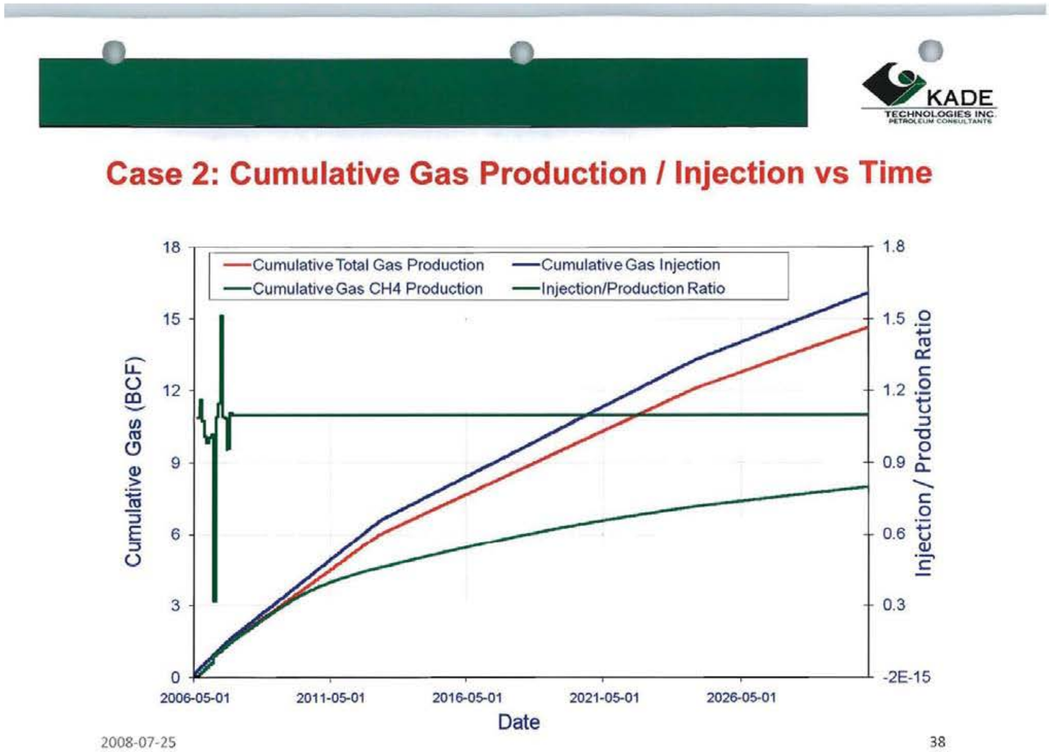
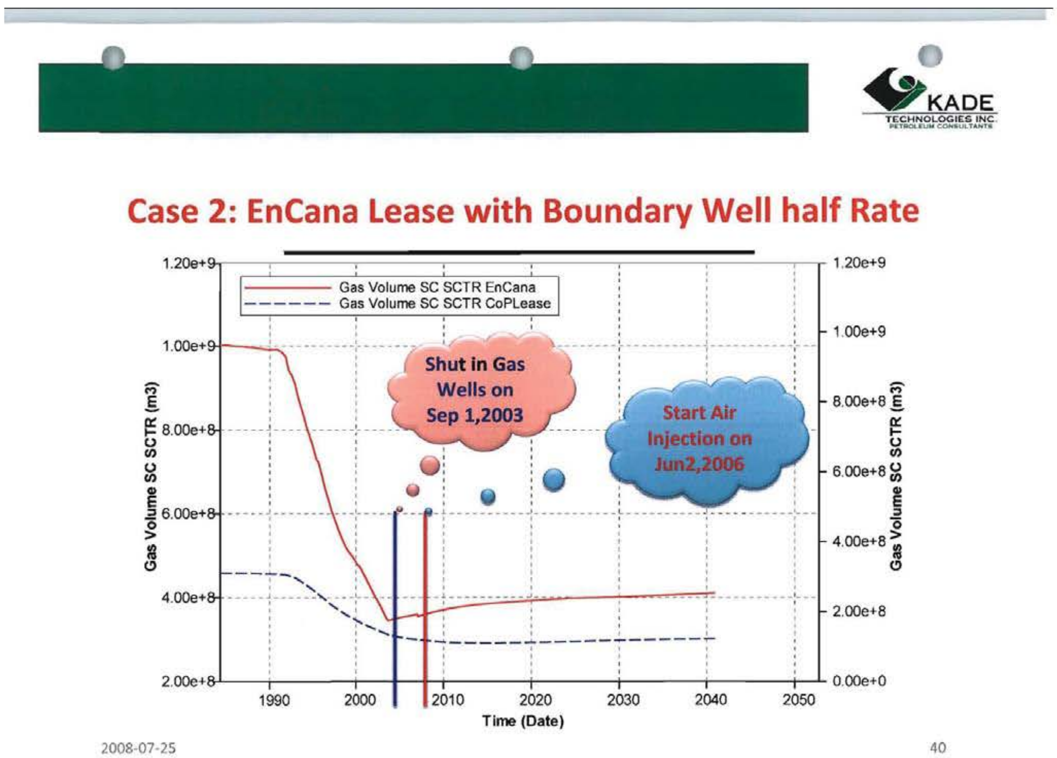
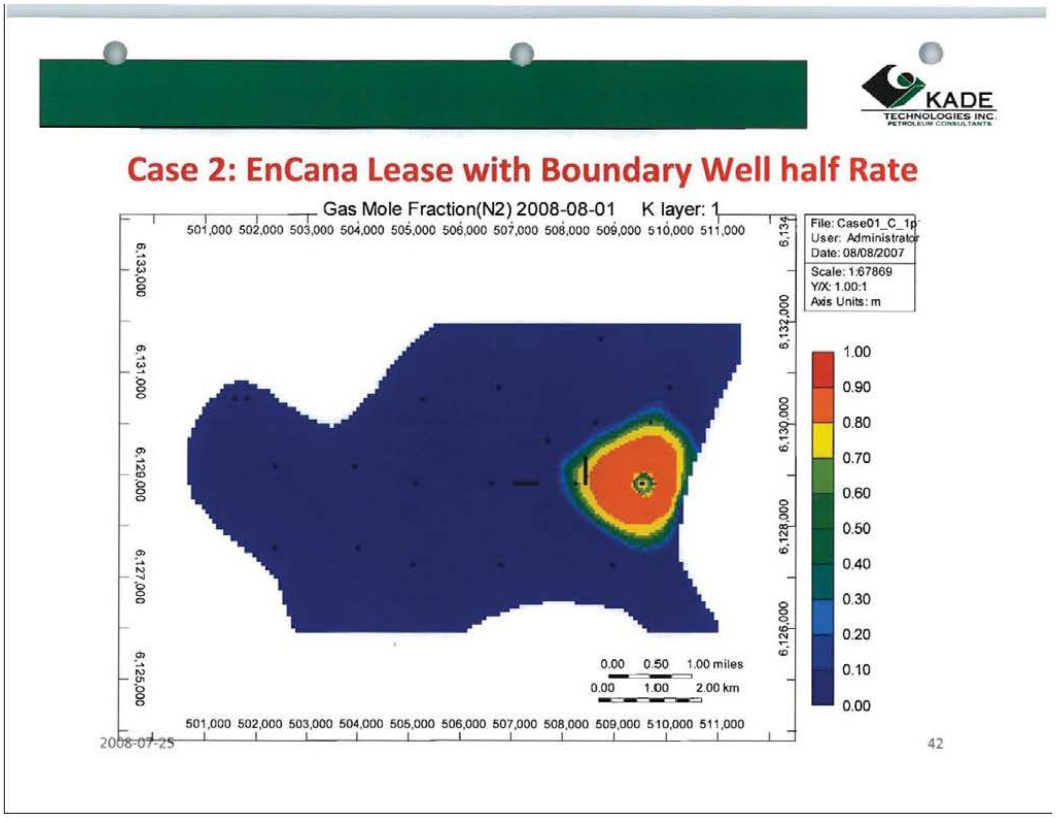
Case 2: EnCana Lease with Boundary Well half Rate



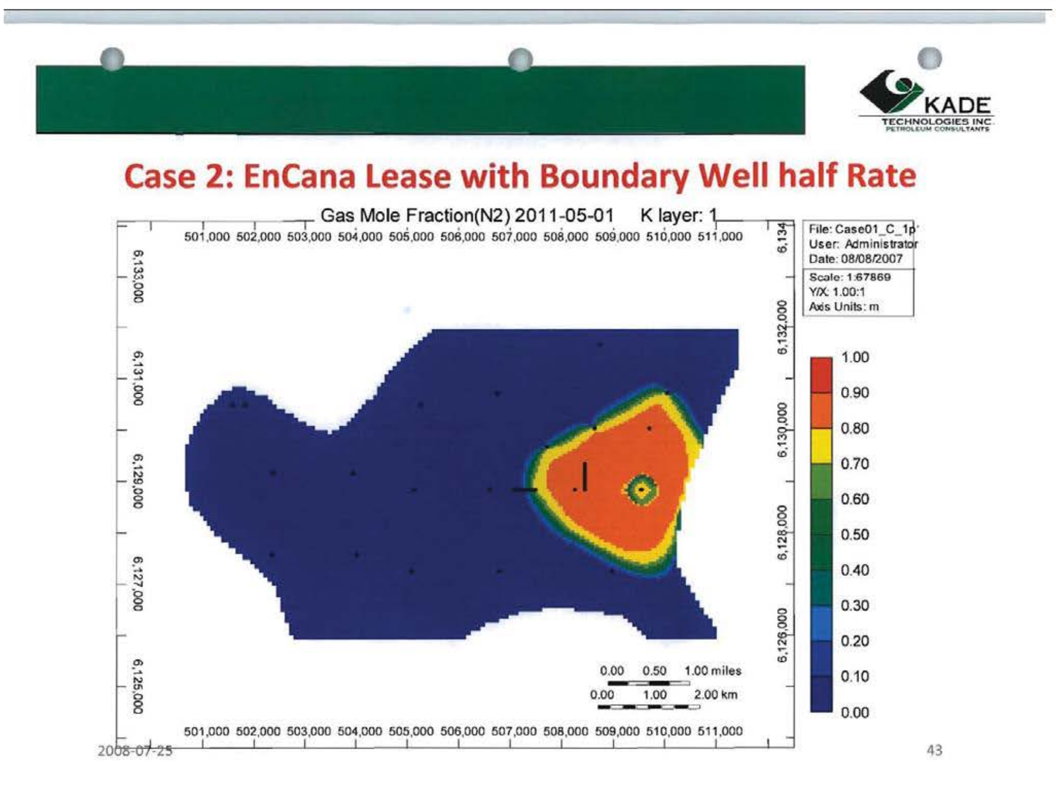
2008-07-25 36


KADE
TECHNOLOGIES INC.
Case 2: Cumulative Gas Production / Injection vs Time
Cumulative Total Gas Production
Cumulative Gas Injection
Cumulative Gas CH4 Production
Injection/Production Ratio
Cumulative Gas (BCF)
Injection / Production Ratio
Date
2006-05-01
2011-05-01
2016-05-01
2021-05-01
2026-05-01
2008-07-25
38


KADE
TECHNOLOGIES INC.
Case 2: EnCana Lease with Boundary Well half Rate
Gas Volume SC SCTR EnCana
Gas Volume SC SCTR CoPLease
Shut in Gas Wells on Sep 1,2003
Start Air Injection on Jun2,2006
Gas Volume SC SCTR (m3)
Time (Date)
2008-07-25
40

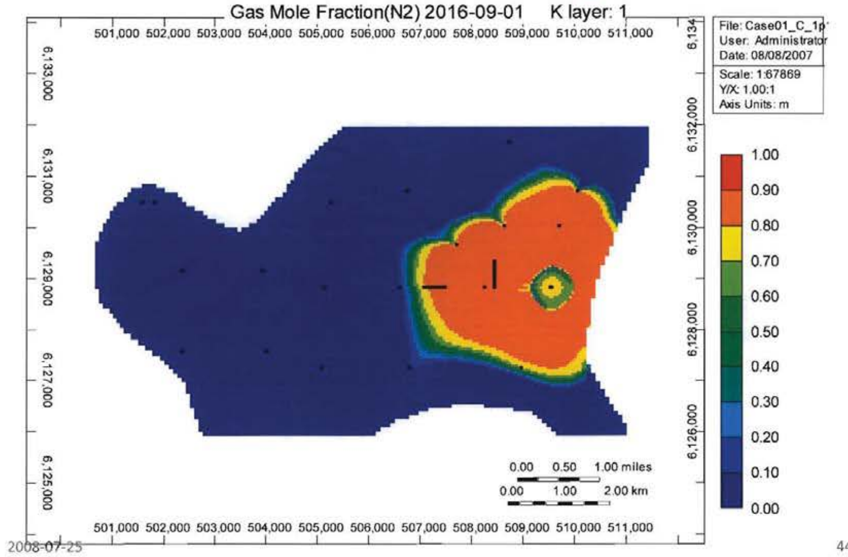


KADE
TECHNOLOGIES INC.
Case 2: EnCana Lease with Boundary Well half Rate
Gas Mole Fraction(N2) 2008-08-01 K layer: 1
File: Case01_C_1p
User: Administrator
Date: 08/08/2007
Scale: 1:67869
Y/X: 1.00:1
Axis Units: m
501,000 502,000 503,000 504,000 505,000 506,000 507,000 508,000 509,000 510,000 511,000
6,133,000 6,131,000 6,129,000 6,127,000 6,125,000
6,134 6,132,000 6,130,000 6,128,000 6,126,000
1.00 0.90 0.80 0.70 0.60 0.50 0.40 0.30 0.20 0.10 0.00
0.00 0.50 1.00 miles
0.00 1.00 2.00 km
2008-07-25
42

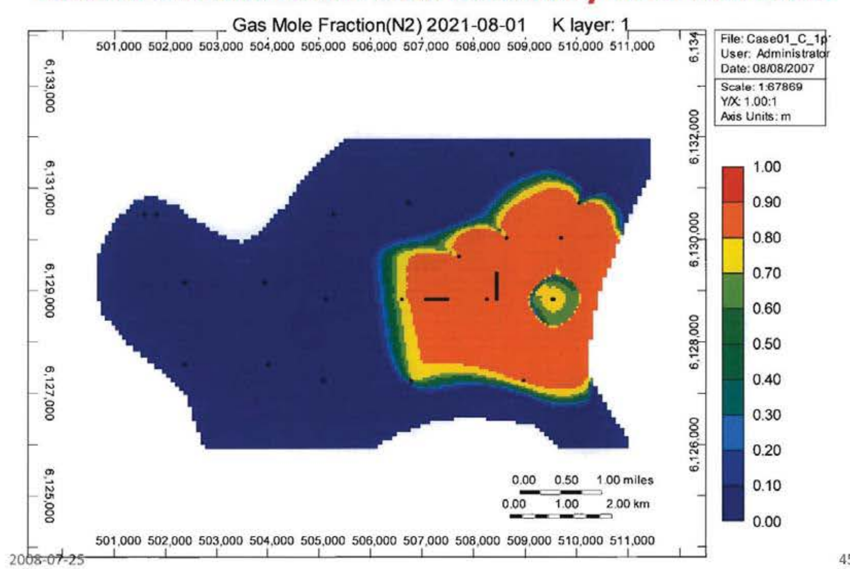


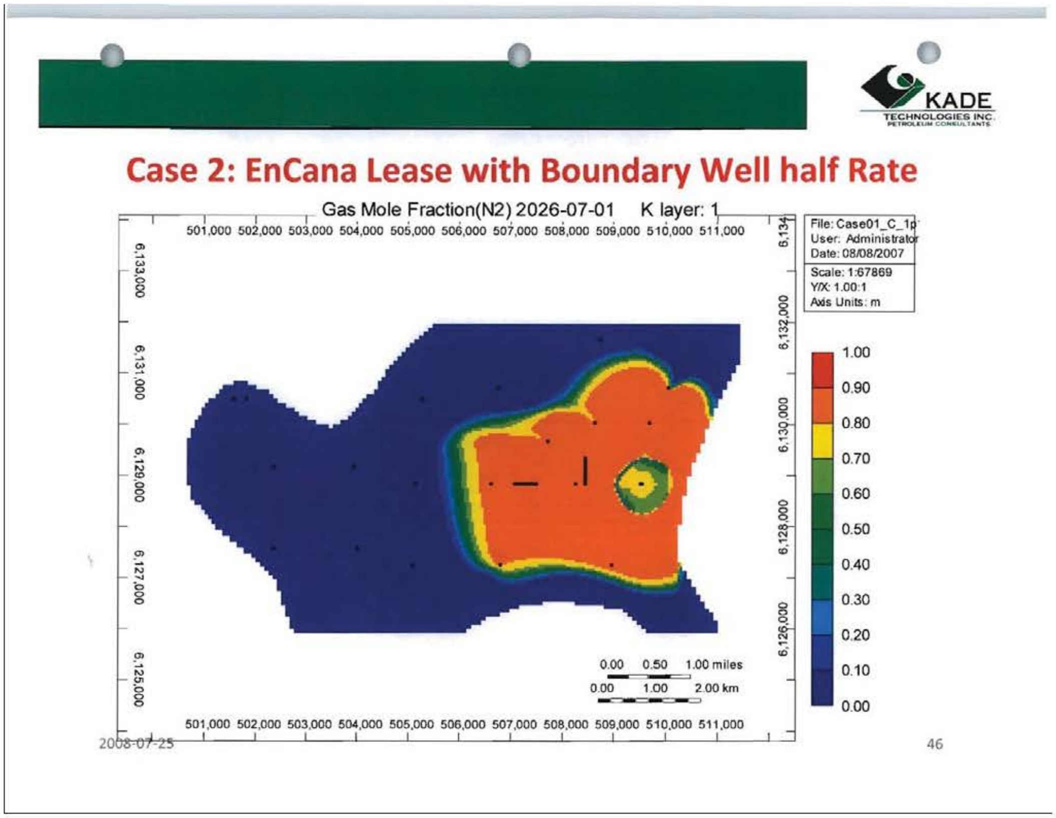
KADE
TECHNOLOGIES INC.
Case 2: EnCana Lease with Boundary Well half Rate
Gas Mole Fraction(N2) 2011-05-01 K layer: 1
File: Case01_C_1p
User: Administrator
Date: 08/08/2007
Scale: 1:67869
Y/X: 1.00:1
Axis Units: m
501,000 502,000 503,000 504,000 505,000 506,000 507,000 508,000 509,000 510,000 511,000
6,133,000 6,131,000 6,129,000 6,127,000 6,125,000
6,134 6,132,000 6,130,000 6,128,000 6,126,000
1.00 0.90 0.80 0.70 0.60 0.50 0.40 0.30 0.20 0.10 0.00
0.00 0.50 1.00 miles
0.00 1.00 2.00 km
2008-07-25
43

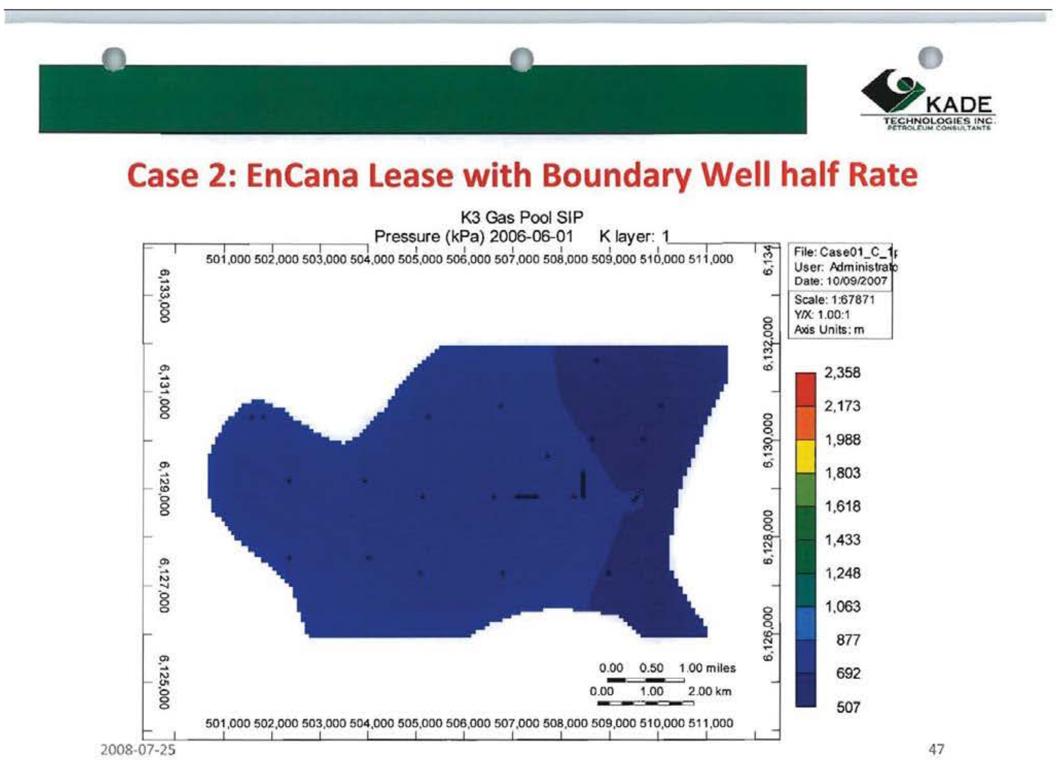
Case 2: EnCana Lease with Boundary Well half Rate



Case 2: EnCana Lease with Boundary Well half Rate

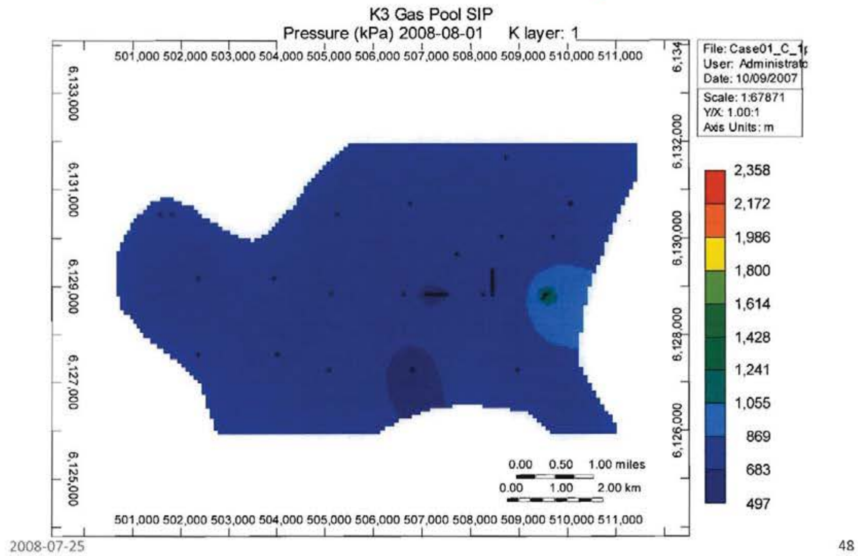



KADE TECHNOLOGIES INC. PETROLEUM CONSULTANTS
Case 2: EnCana Lease with Boundary Well half Rate
Gas Mole Fraction(N2) 2026-07-01 K layer: 1
501,000 502,000 503,000 504,000 505,000 506,000 507,000 508,000 509,000 510,000 511,000
6,133,000
6,131,000
6,129,000
6,127,000
6,125,000
6,134
6,132,000
6,130,000
6,128,000
6,126,000
File: Case01_C_1p
User: Administrator
Date: 08/08/2007
Scale: 1:67869
Y/X: 1.00:1
Axis Units: m
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0.00 0.50 1.00 miles
0.00 1.00 2.00 km
2008-07-25
46


KADE TECHNOLOGIES INC. PETROLEUM CONSULTANTS
Case 2: EnCana Lease with Boundary Well half Rate
K3 Gas Pool SIP
Pressure (kPa) 2006-06-01 K layer: 1
501,000 502,000 503,000 504,000 505,000 506,000 507,000 508,000 509,000 510,000 511,000
6,133,000
6,131,000
6,129,000
6,127,000
6,125,000
6,134
6,132,000
6,130,000
6,128,000
6,126,000
File: Case01_C_1
User: Administrato
Date: 10/09/2007
Scale: 1:67871
Y/X: 1.00:1
Axis Units: m
2,358
2,173
1,988
1,803
1,618
1,433
1,248
1,063
877
692
507
0.00 0.50 1.00 miles
0.00 1.00 2.00 km
2008-07-25
47

KADE TECHNOLOGIES INC. PETROLEUM CONSULTANTS

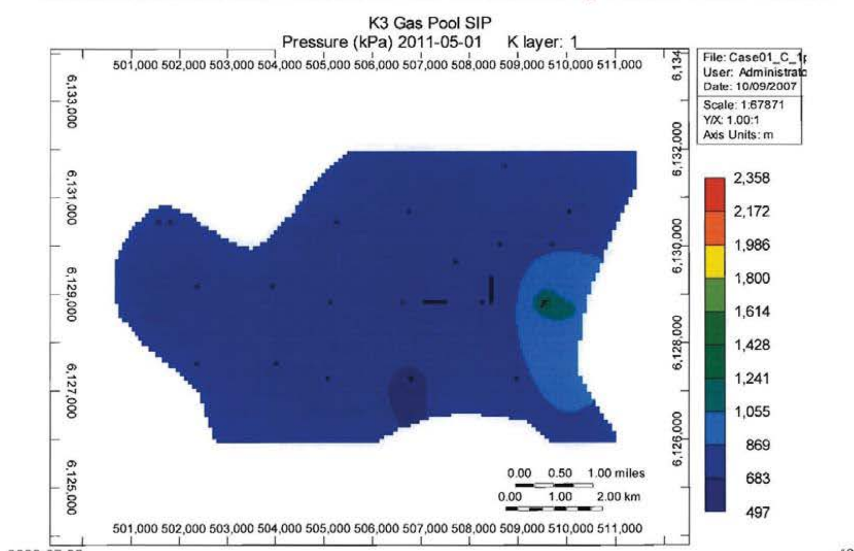
Case 2: EnCana Lease with Boundary Well half Rate



2008-07-25 48

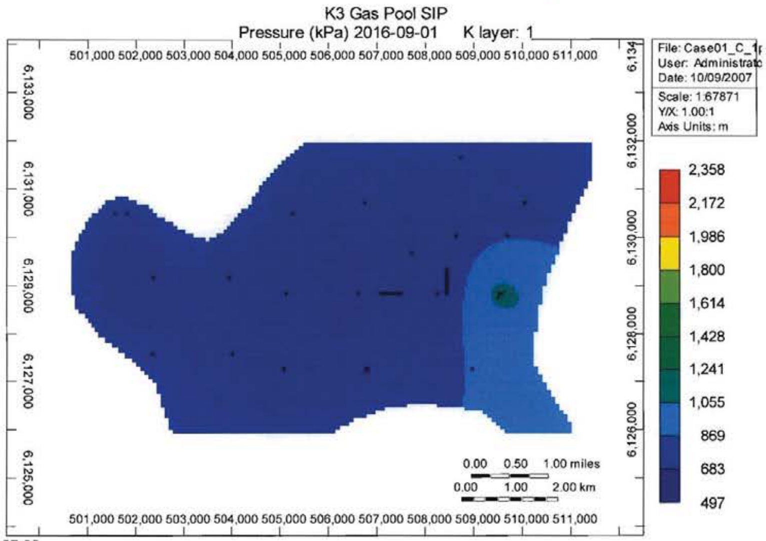
KADE TECHNOLOGIES INC. PETROLEUM CONSULTANTS

Case 2: EnCana Lease with Boundary Well half Rate



2008-07-25 49

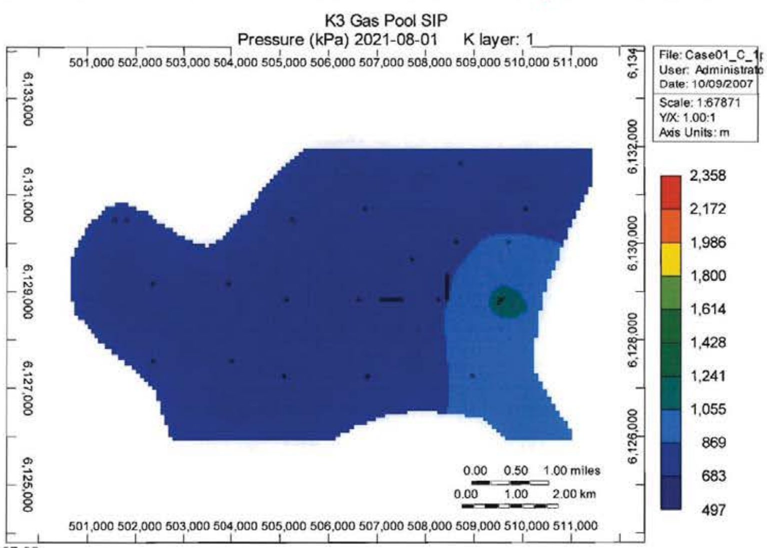
Case 2: EnCana Lease with Boundary Well half Rate



2008-07-25

50

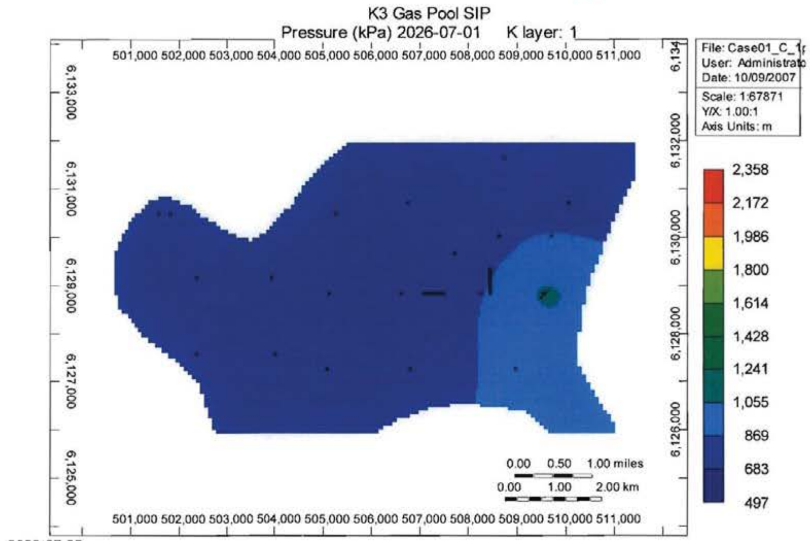
Case 2: EnCana Lease with Boundary Well half Rate



2008-07-25

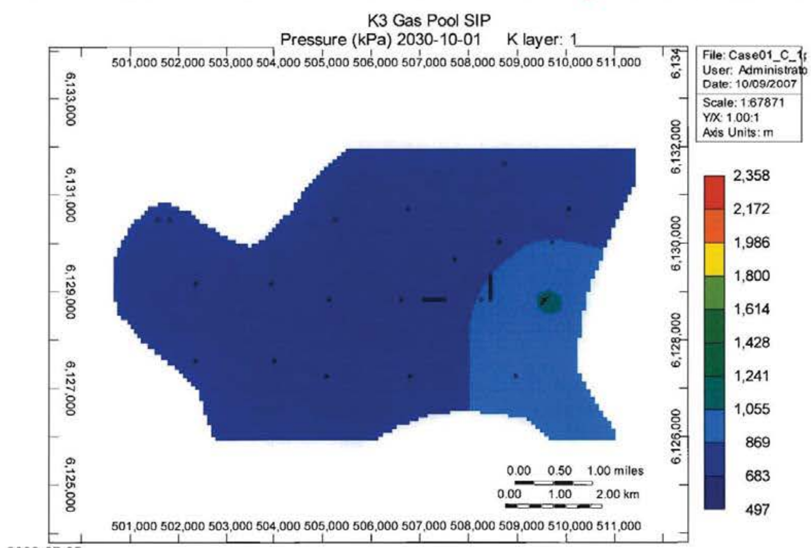
51

Case 2: EnCana Lease with Boundary Well half Rate



2008-07-25 52

Case 2: EnCana Lease with Boundary Well half Rate



2008-07-25 53

Appendix D: Estimate of Bitumen Impact

Issue: Heat Effects in Bitumen

Assumptions

- Combustion Front Location establishes area of influence in gas zone
  - Consume about 7 to 10% trapped residual bitumen in gas zone
  - Small displacement and banking of oil in front of combustion area
- Steam zone at 200+ Deg C sits about 20 meters in front of combustion area
- "Chemically altered" area in bitumen below gas is contained to about 2/3 rds of the radius of the combustion zone
  - Estimate only 25% of the oil in this region is "coked"
  - 75% of the oil is swept ahead along G/B interface or up into gas zone
  - Swept volume is "not consumed" and could eventually be recovered
- "Thermally stimulated" area and volume are calculated as anywhere that is above 60 Deg C and not chemically altered
  - 60 Deg C results in an oil viscosity of about 600 cp which is moveable
  - Below injector the depth of "stimulation" is estimated at about 16 meters from obs well (30 meters away) with 11 – 13 meters of bitumen above 60 Deg C
  - Expect that under largest radius of steam and combustion influence, the bitumen should be warmed up to 60 Deg C to at least 4 meters
- Original EnCAID Application identified 120,000 m3 of bitumen to be affected based on all volumes that would be heated.
  - Didn't differentiate between "chemically altered" and "thermally stimulated" areas
  - Assumed less heat effects into most of the bitumen (only few meters) but assumed the process would run for 16+ years (to 2022) and have a final combustion radius of 360 meters

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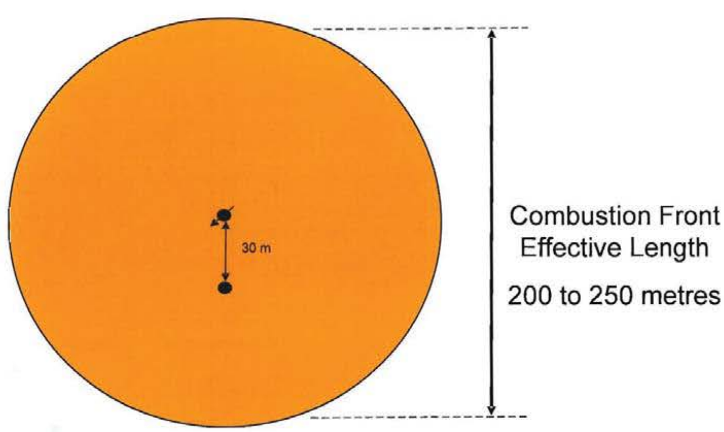
EnCAID Impact

Heated Region Radiates from Injector



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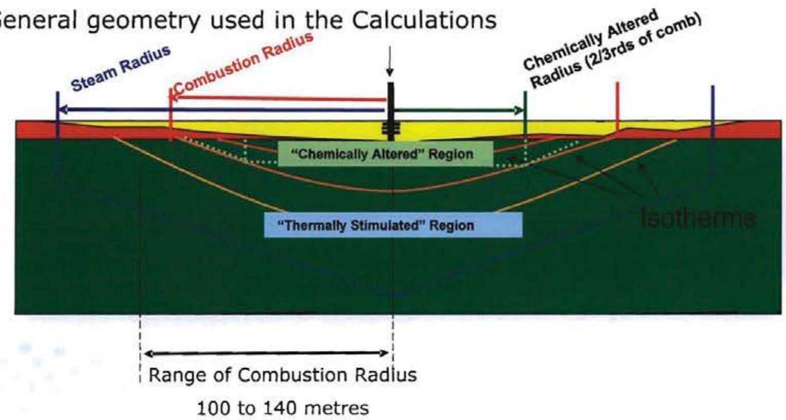
EnCAID Impact - Heated Volume Diagram

General geometry used in the Calculations



Estimate of Front Position from Material Balance on Combustion Calculation

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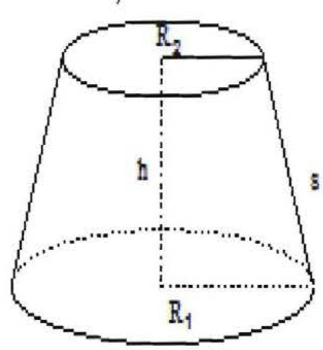
Issue: Calculation of Heat Effects in Bitumen

- Bitumen with increased temperature should have the shape of an inverted conical frustum

- Volume of a Conical Frustum $V = \frac{1}{3}\pi h\left(R_1^2 + R_2^2 + R_1 R_2\right)$



R1 = radius of Base
R2 = radius of upper Base
V = volume

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Issue: Heat Effects in Bitumen

Calculations

- Current Day
  - Burned Radius ~= 103 meters
  - Chemically Altered Volume ~= 6,400 m³ of oil
  - Thermally Stimulated Volume ~= 71,000 m³ of oil
  - Total Affected Volume = Chemically + Thermally ~= 77,400 m³ of oil
- March 2012 Approval (Forecast)
  - Burned Radius ~= 124 meters
  - Chemically Altered Volume ~= 9,200 m³ of oil
  - Thermally Stimulated Volume ~= 102,000m³ of oil
  - Total Affected Volume = Chemically + Thermally ~= 111,200 m³ of oil
- East Side Gas Depletion to 2014/2015 (Forecast)
  - Burned Radius ~= 140 meters
  - Chemically Altered Volume ~= 11,700 m³ of oil
  - Thermally Stimulated Volume ~= 131,000 m³ of oil
  - Total Affected Volume = Chemically + Thermally ~= 142,700 m³ of oil
- Original EnCAID Application identified 120,000 m³ of bitumen to be affected based on all volumes that would be heated at all.

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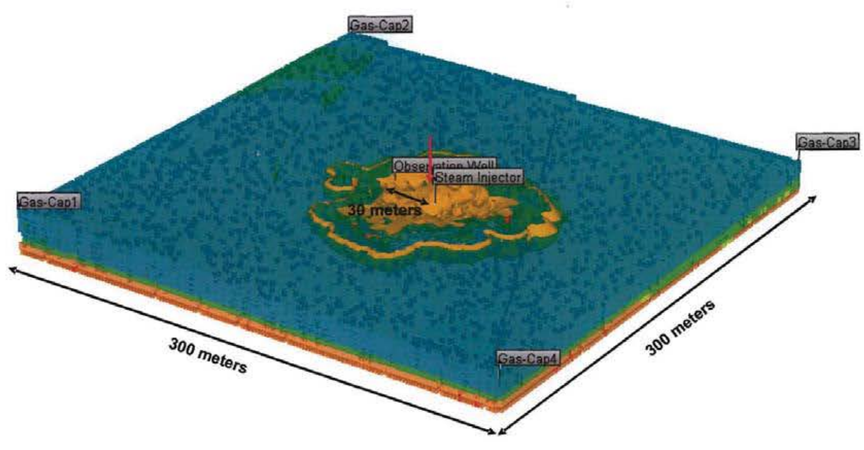
EnCAID History Match
Top View - Visualization



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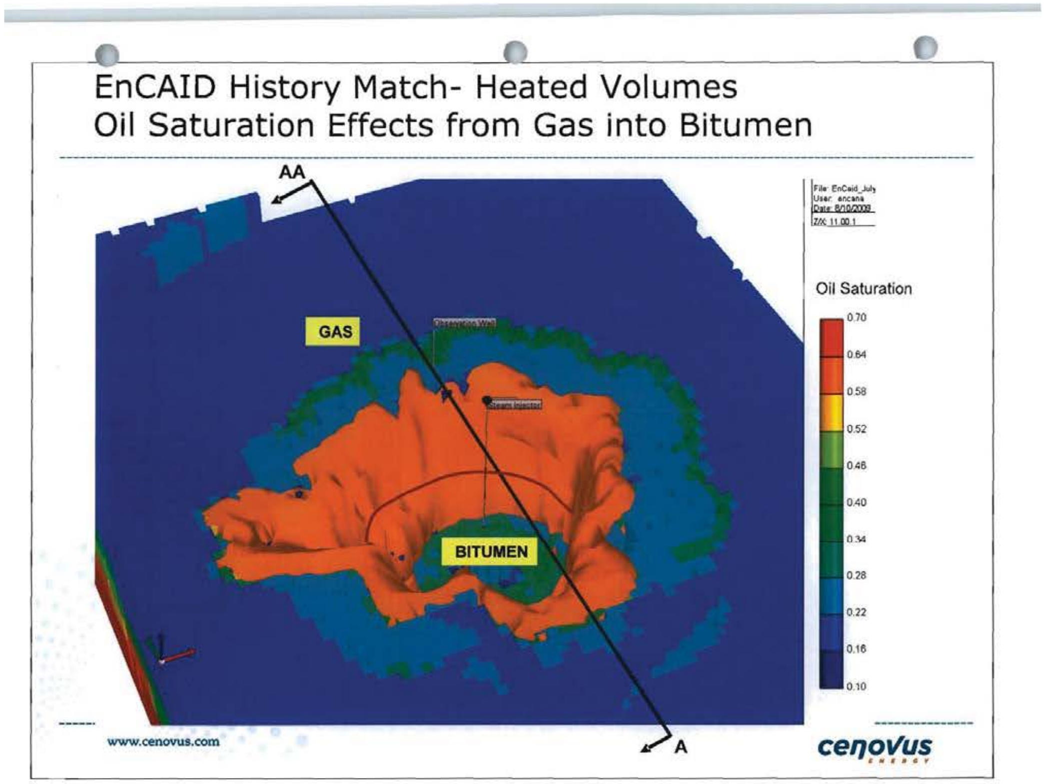
EnCAID History Match- Heated Volumes
Oil Saturation Effects from Gas into Bitumen
AA
GAS
BITUMEN
Oil Saturation
0.70
0.64
0.58
0.52
0.46
0.40
0.34
0.28
0.22
0.16
0.10
A
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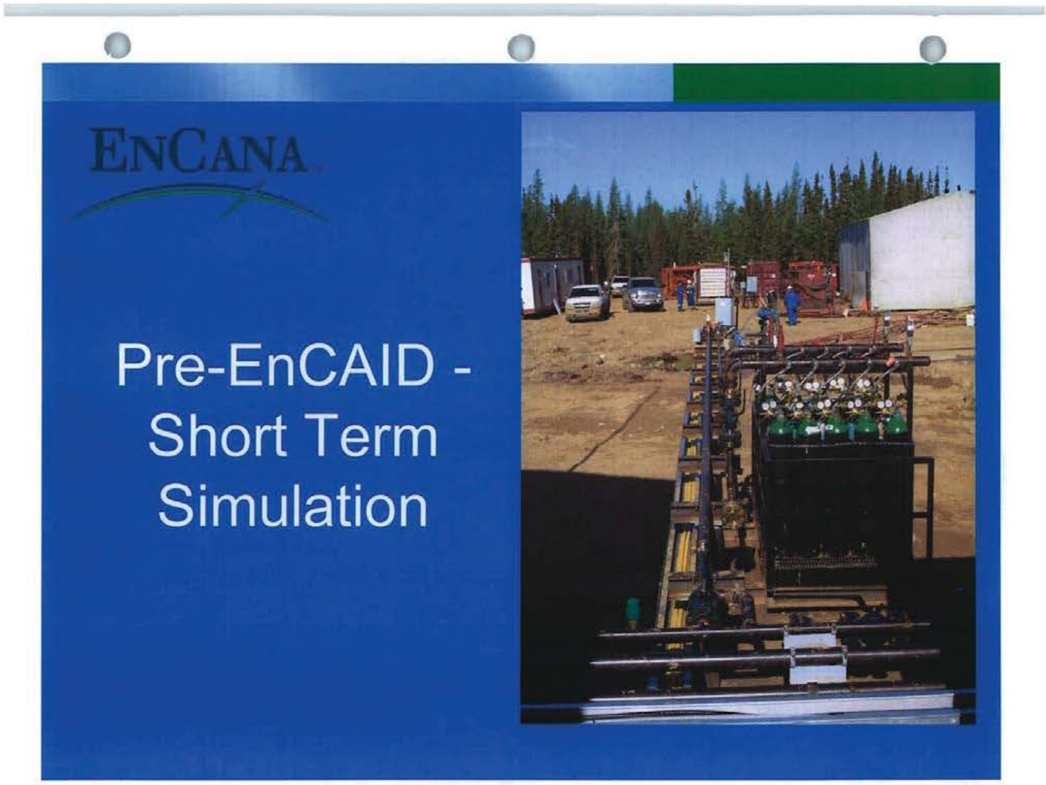
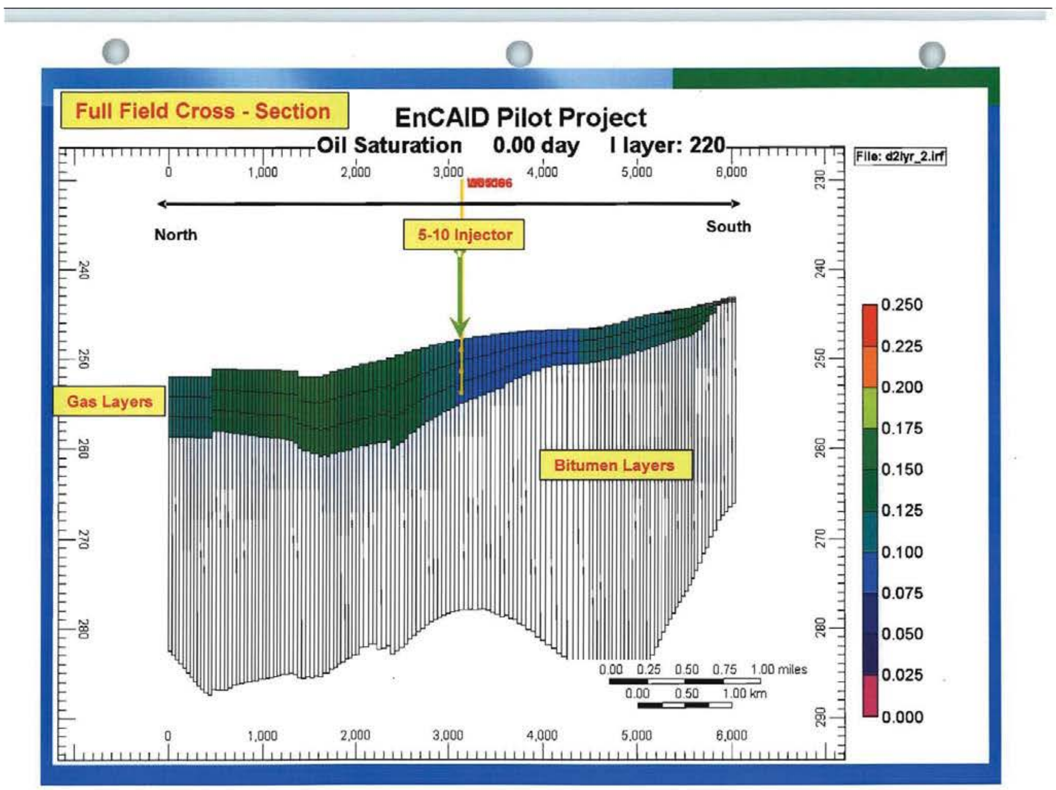
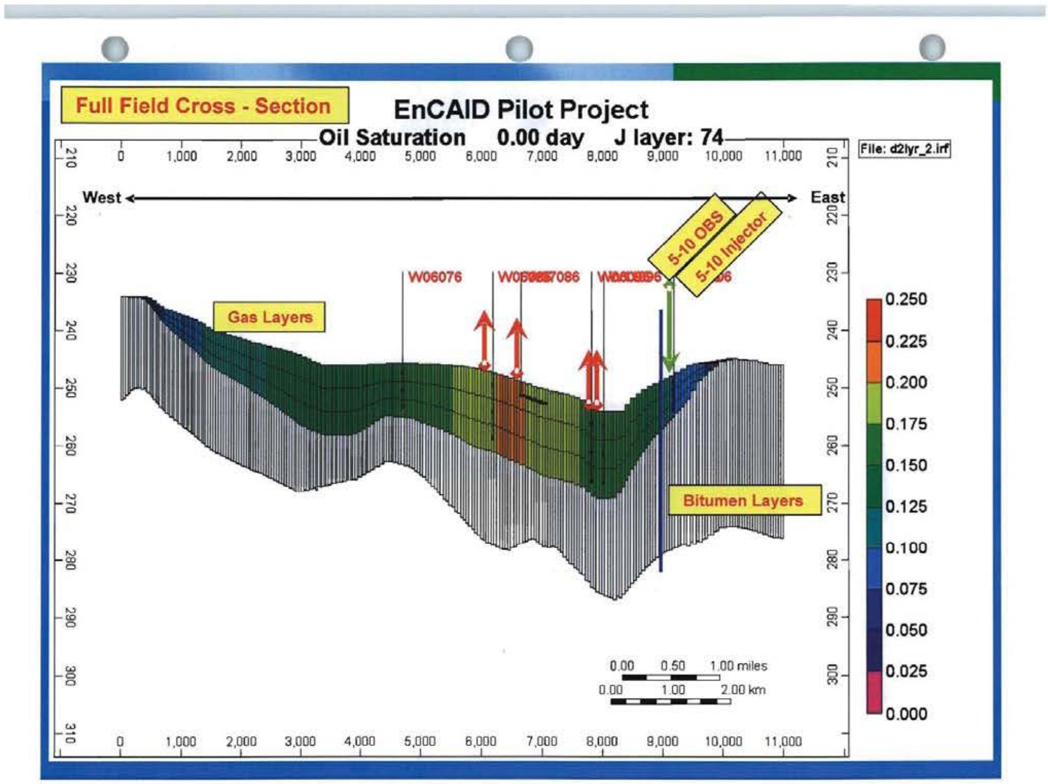
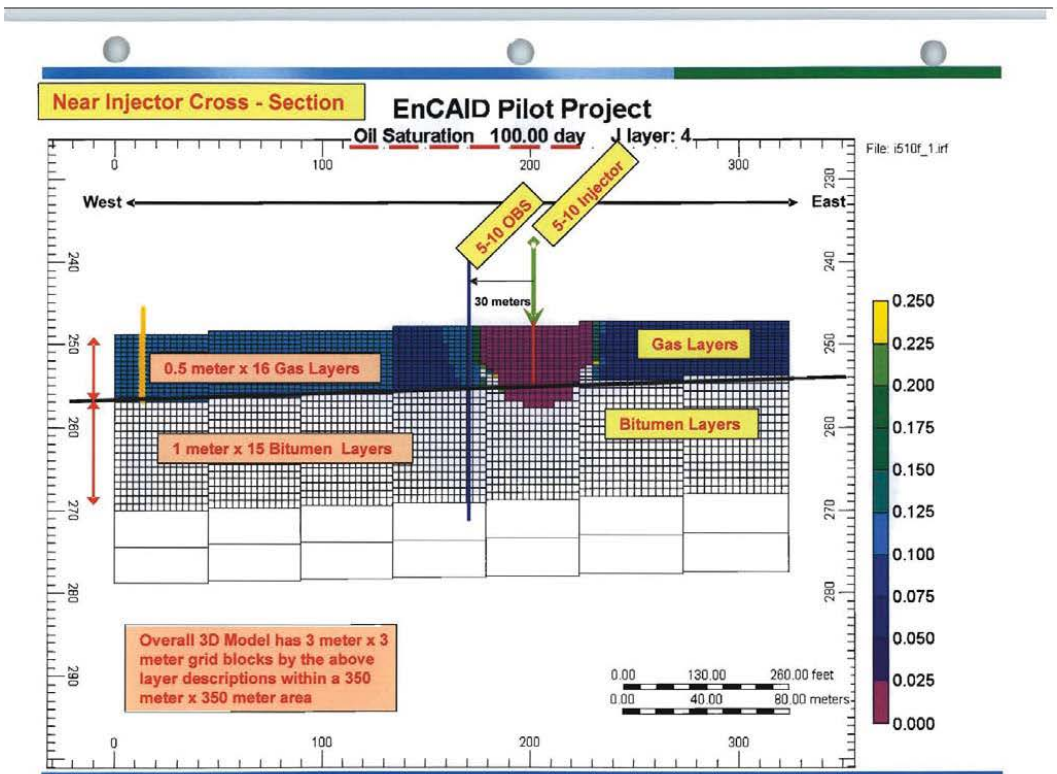
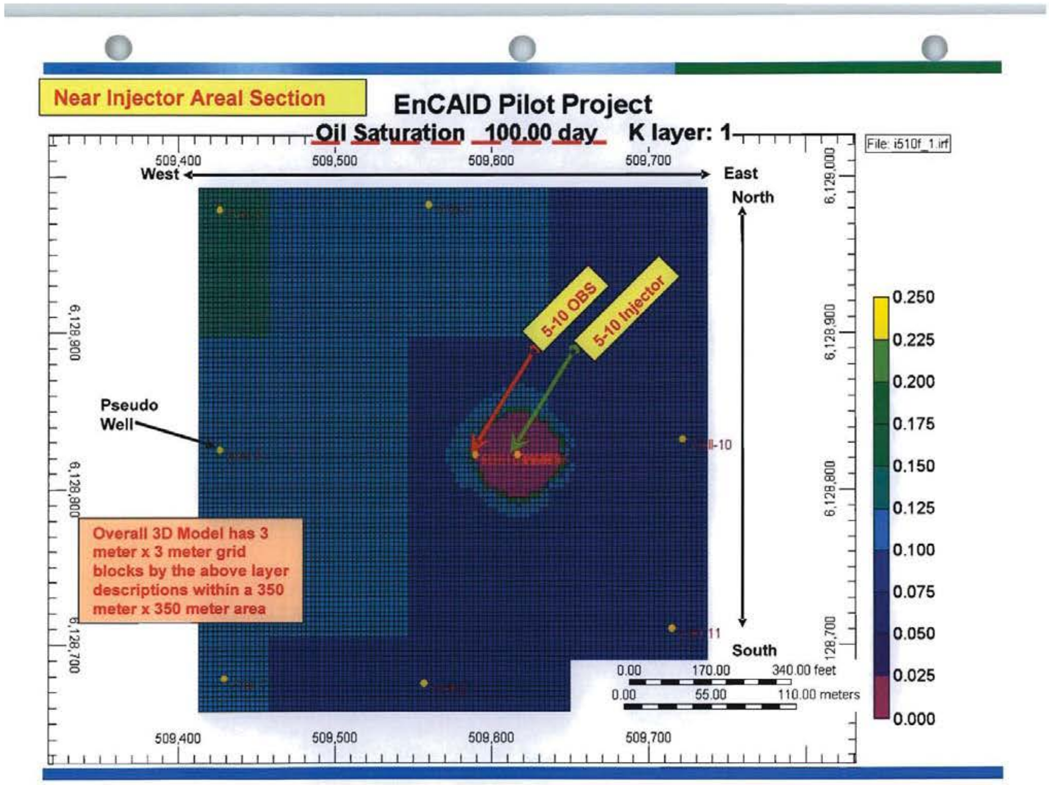
Appendix D: Short Term Simulation

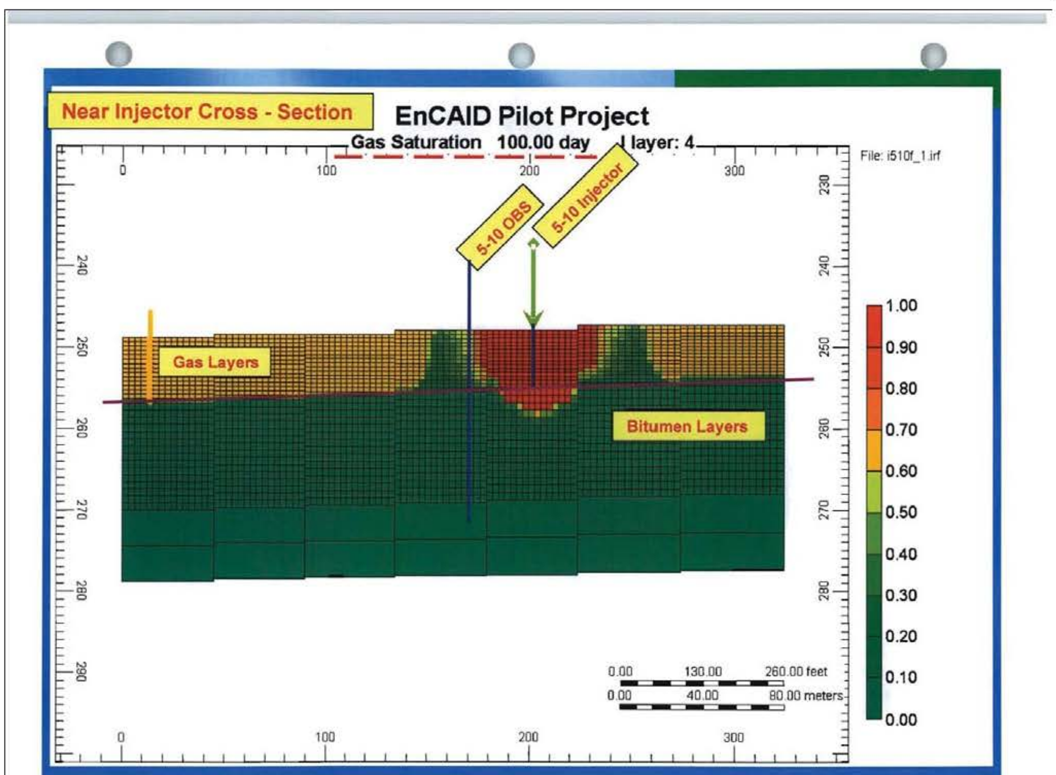

ENCANA
Pre-EnCAID -
Short Term
Simulation

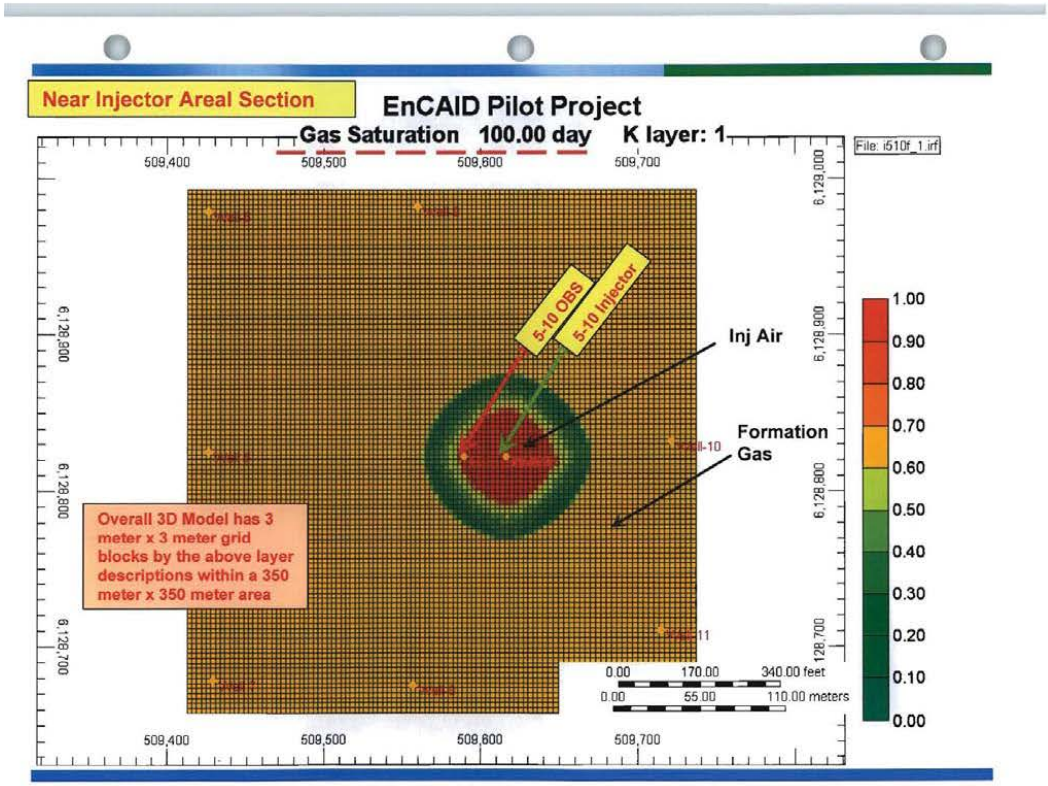

Full Field Cross - Section
EnCAID Pilot Project
Oil Saturation 0.00 day I layer: 220
File: d2lyr_2.irf
North
South
5-10 Injector
Gas Layers
Bitumen Layers
0 1,000 2,000 3,000 4,000 5,000 6,000
230 240 250 260 270 280 290
0.00 0.25 0.50 0.75 1.00 miles
0.00 0.50 1.00 km
0.250
0.225
0.200
0.175
0.150
0.125
0.100
0.075
0.050
0.025
0.000

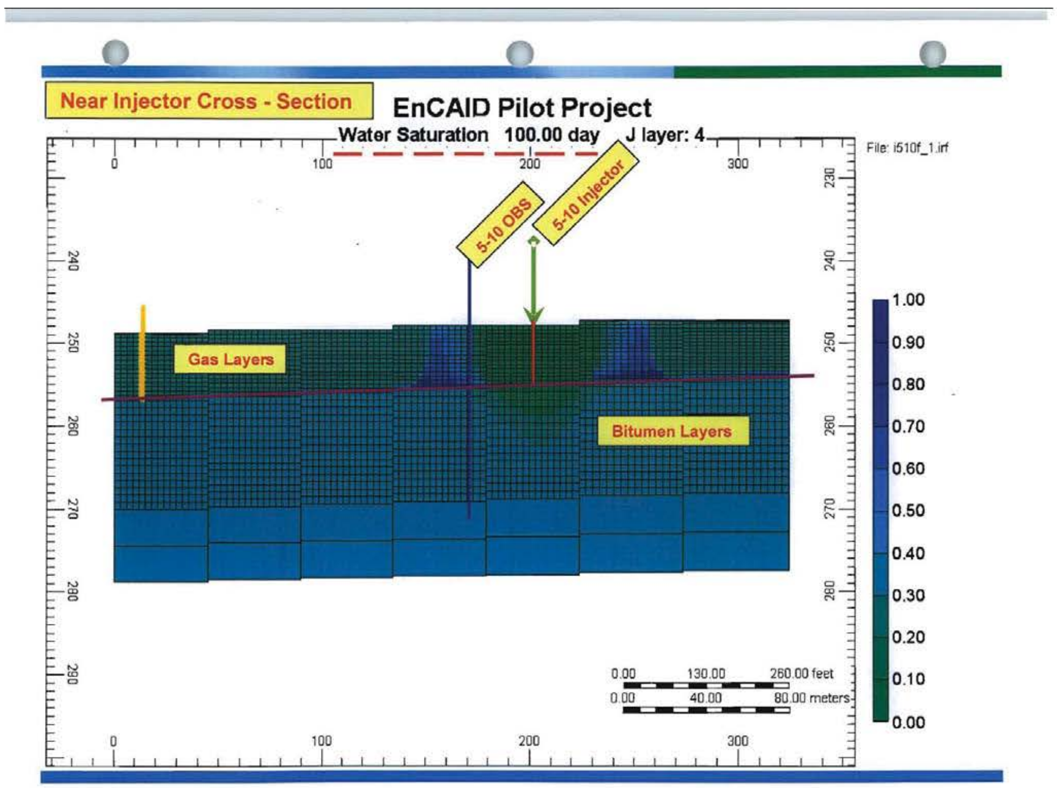

Full Field Cross - Section
EnCAID Pilot Project
Oil Saturation 0.00 day J layer: 74
File: d2lyr_2.irf
West
East
5-10 OBS
5-10 Injector
W06076
Gas Layers
Bitumen Layers
0.00 0.50 1.00 miles
0.00 1.00 2.00 km

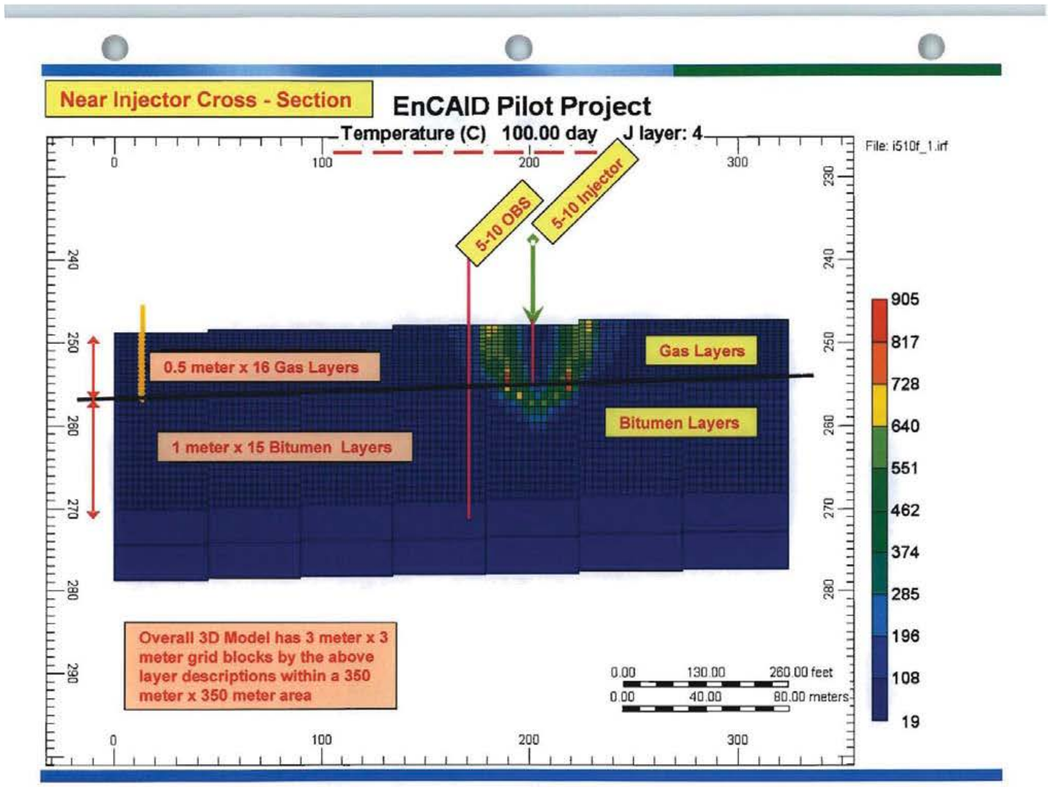

Near Injector Cross - Section
EnCAID Pilot Project
Oil Saturation 100.00 day J layer: 4
File: i510f_1.irf
West
East
5-10 OBS
5-10 Injector
30 meters
0.5 meter x 16 Gas Layers
1 meter x 15 Bitumen Layers
Gas Layers
Bitumen Layers
Overall 3D Model has 3 meter x 3 meter grid blocks by the above layer descriptions within a 350 meter x 350 meter area
0.00 130.00 260.00 feet
0.00 40.00 80.00 meters

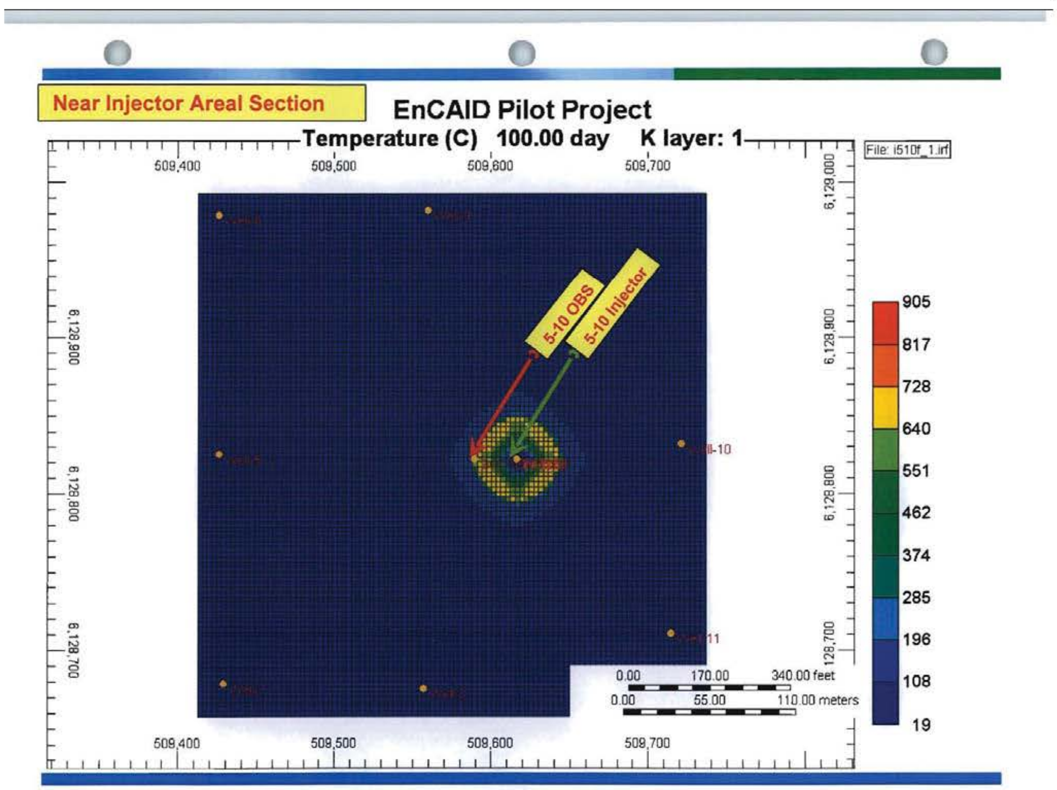

Near Injector Areal Section
EnCAID Pilot Project
Oil Saturation 100.00 day K layer: 1
File: i510f_1.irf
West
East
North
South
5-10 OBS
5-10 Injector
Pseudo Well
Overall 3D Model has 3 meter x 3 meter grid blocks by the above layer descriptions within a 350 meter x 350 meter area
509,400
509,500
509,600
509,700
6,129,000
6,128,900
6,128,800
6,128,700
0.00 170.00 340.00 feet
0.00 55.00 110.00 meters
0.250
0.225
0.200
0.175
0.150
0.125
0.100
0.075
0.050
0.025
0.000

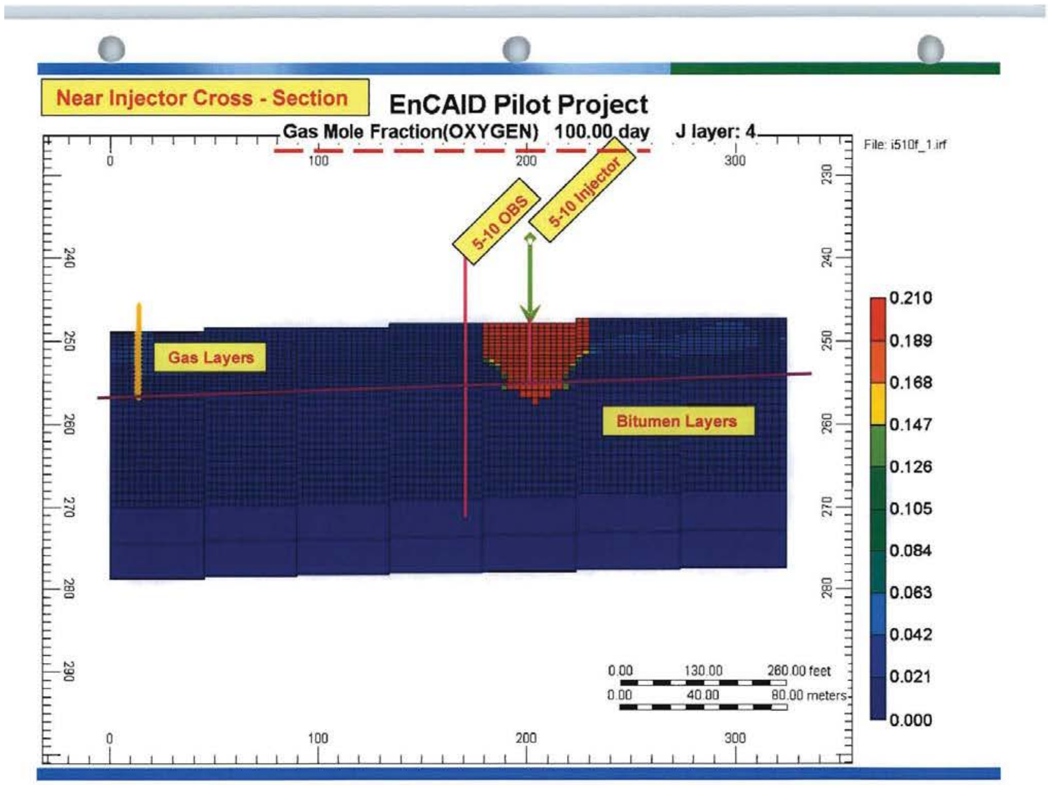

Near Injector Cross - Section
EnCAID Pilot Project
Gas Saturation 100.00 day J layer: 4
File: i510f_1.irf
5-10 OBS
5-10 Injector
Gas Layers
Bitumen Layers
0
100
200
300
230
240
250
260
270
280
290
0.00 130.00 260.00 feet
0.00 40.00 80.00 meters
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00


Near Injector Areal Section
EnCAID Pilot Project
Gas Saturation 100.00 day K layer: 1
File: i510f_1.irf
5-10 OBS
5-10 Injector
Inj Air
Formation Gas
Overall 3D Model has 3 meter x 3 meter grid blocks by the above layer descriptions within a 350 meter x 350 meter area
509,400
509,500
509,600
509,700
6,129,000
6,128,900
6,128,800
6,128,700
0.00 170.00 340.00 feet
0.00 55.00 110.00 meters
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00

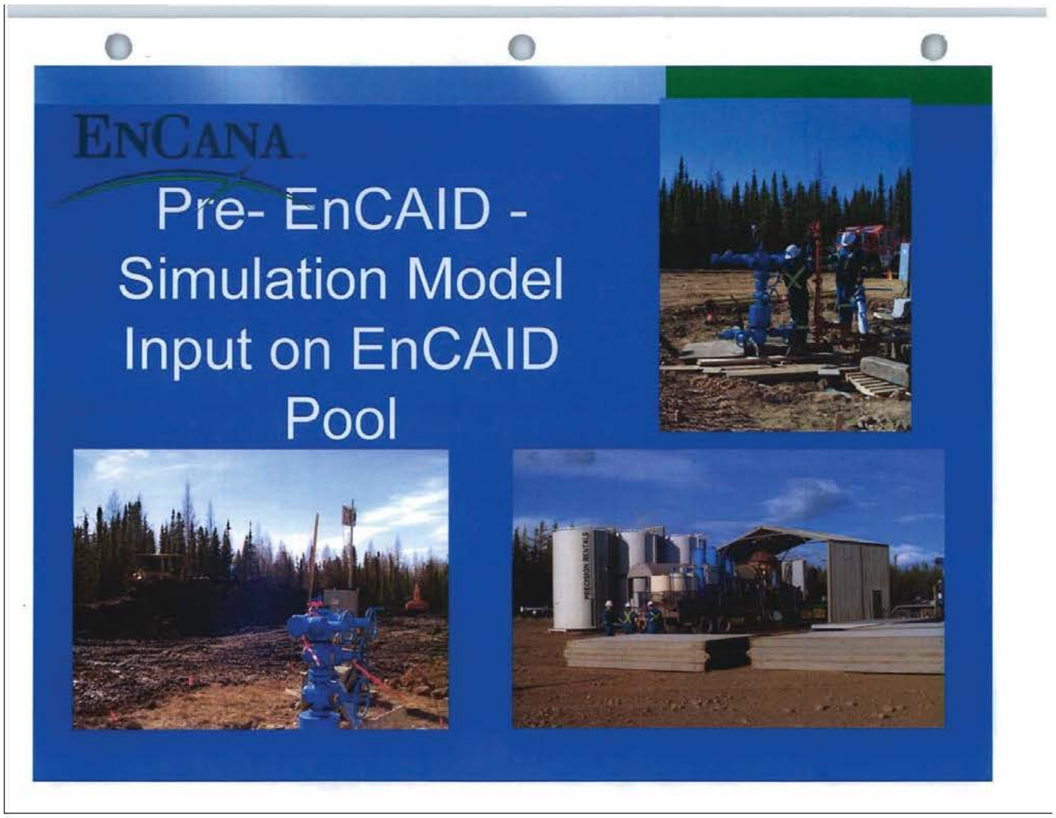

Near Injector Cross - Section
EnCAID Pilot Project
Water Saturation 100.00 day J layer: 4
File: i510f_1.irf
5-10 OBS
5-10 Injector
Gas Layers
Bitumen Layers
0
100
200
300
230
240
250
260
270
280
290
0.00 130.00 260.00 feet
0.00 40.00 80.00 meters
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00

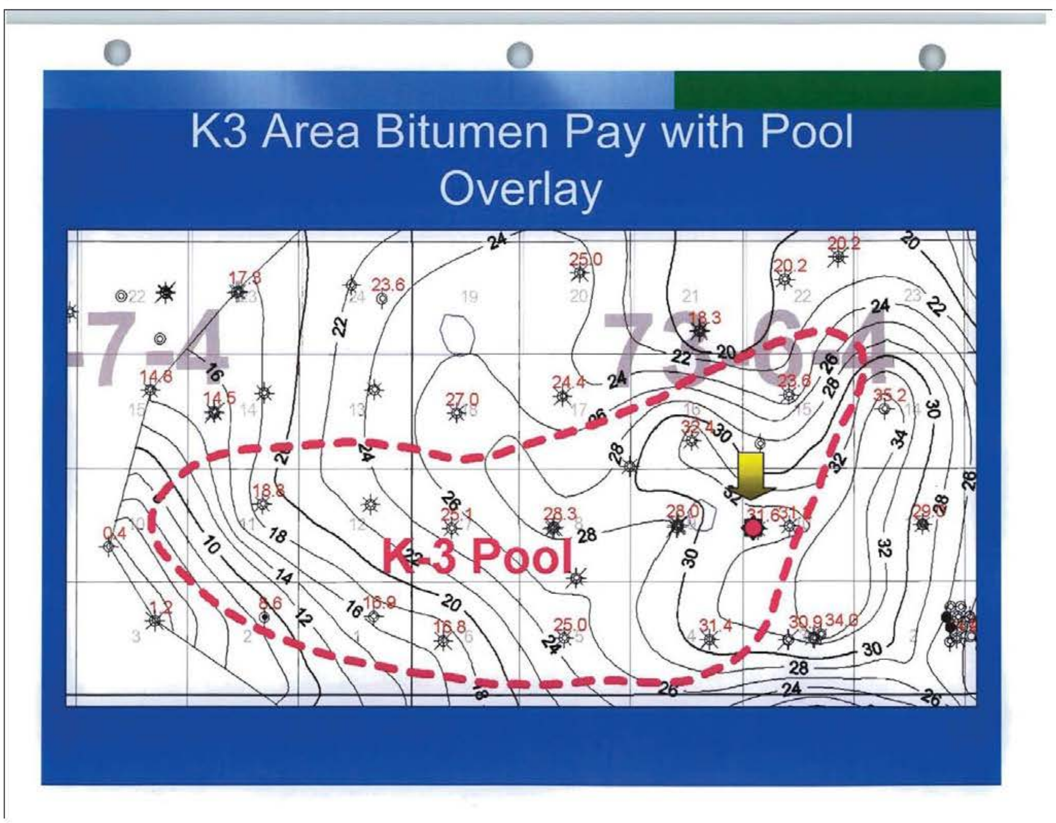

Near Injector Cross - Section
EnCAID Pilot Project
Temperature (C) 100.00 day J layer: 4
File: i510f_1.irf
5-10 OBS
5-10 Injector
0.5 meter x 16 Gas Layers
1 meter x 15 Bitumen Layers
Gas Layers
Bitumen Layers
Overall 3D Model has 3 meter x 3 meter grid blocks by the above layer descriptions within a 350 meter x 350 meter area
0.00 130.00 260.00 feet
0.00 40.00 80.00 meters
905
817
728
640
551
462
374
285
196
108
19

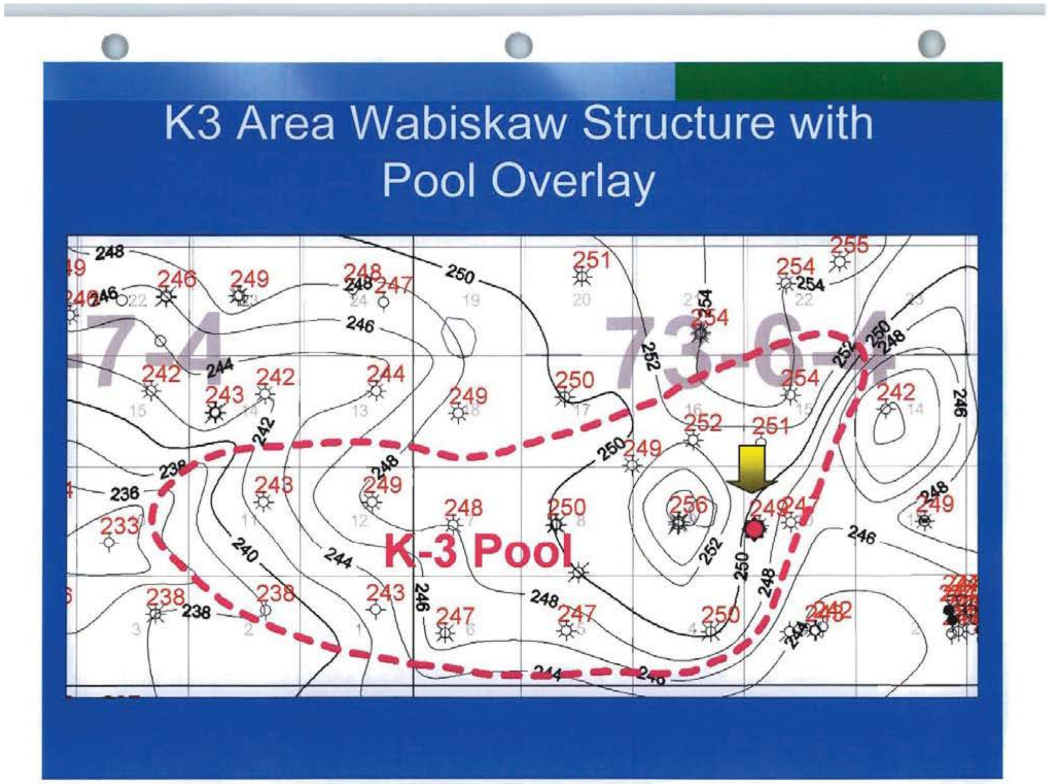

Near Injector Areal Section
EnCAID Pilot Project
Temperature (C) 100.00 day K layer: 1
File: i510f_1.irf
5-10 OBS
5-10 Injector
0.00 170.00 340.00 feet
0.00 55.00 110.00 meters
905
817
728
640
551
462
374
285
196
108
19

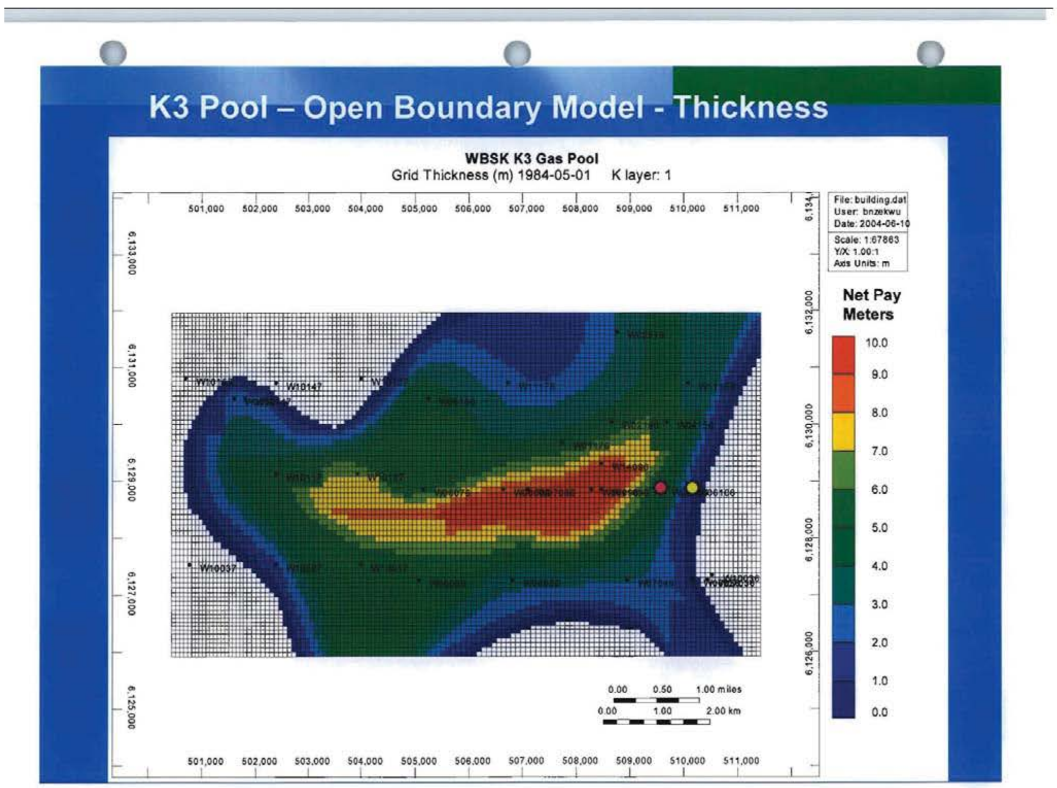

Near Injector Cross - Section
EnCAID Pilot Project
Gas Mole Fraction(OXYGEN) 100.00 day J layer: 4
5-10 OBS
5-10 Injector
Gas Layers
Bitumen Layers
0.210
0.189
0.168
0.147
0.126
0.105
0.084
0.063
0.042
0.021
0.000
0.00 130.00 260.00 feet
0.00 40.00 80.00 meters

Appendix D: Simulation Model Input


ENCANA
Pre- EnCAID -
Simulation Model
Input on EnCAID
Pool


K3 Area Bitumen Pay with Pool
Overlay
K-3 Pool

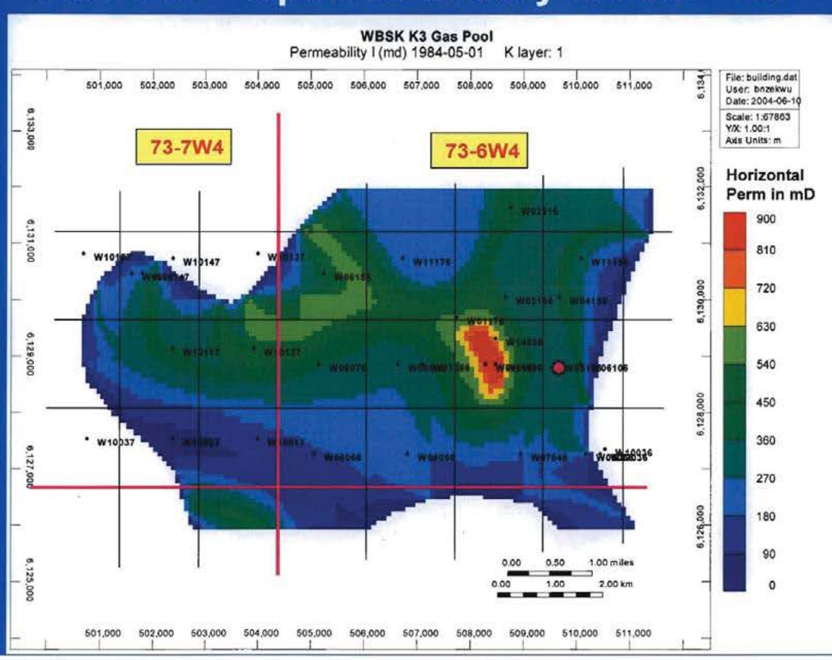

K3 Area Wabiskaw Structure with Pool Overlay
K-3 Pool

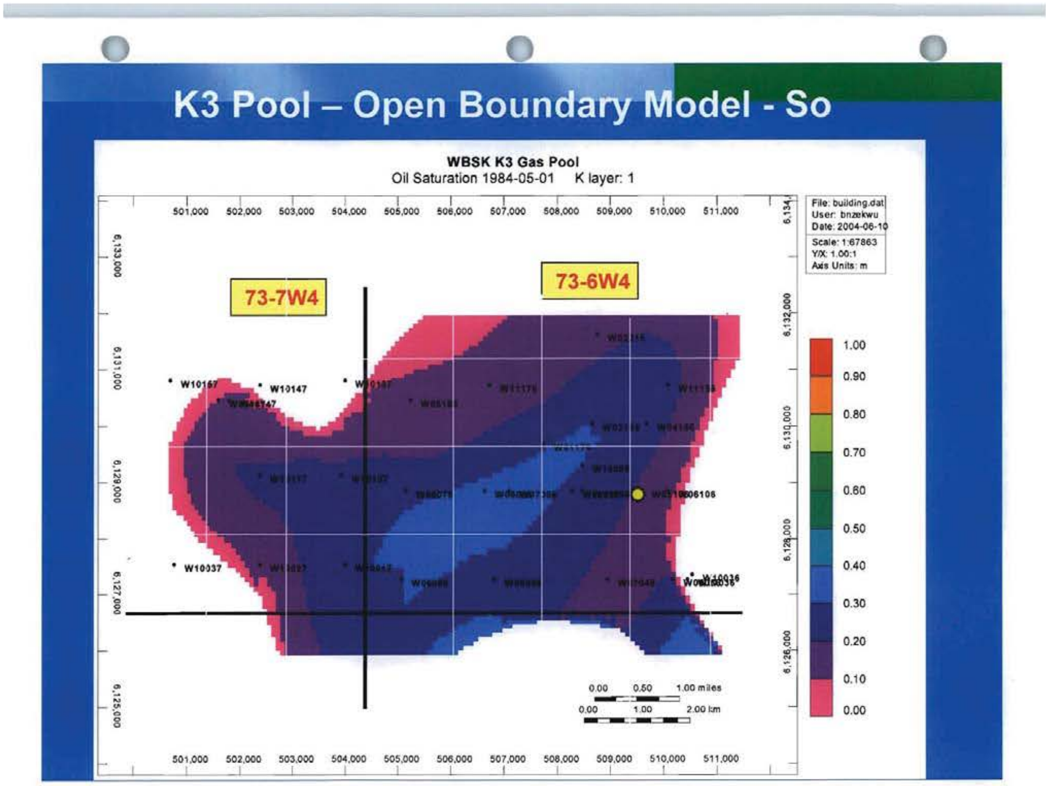

K3 Pool – Open Boundary Model - Thickness
WBSK K3 Gas Pool
Grid Thickness (m) 1984-05-01 K layer: 1
Net Pay Meters

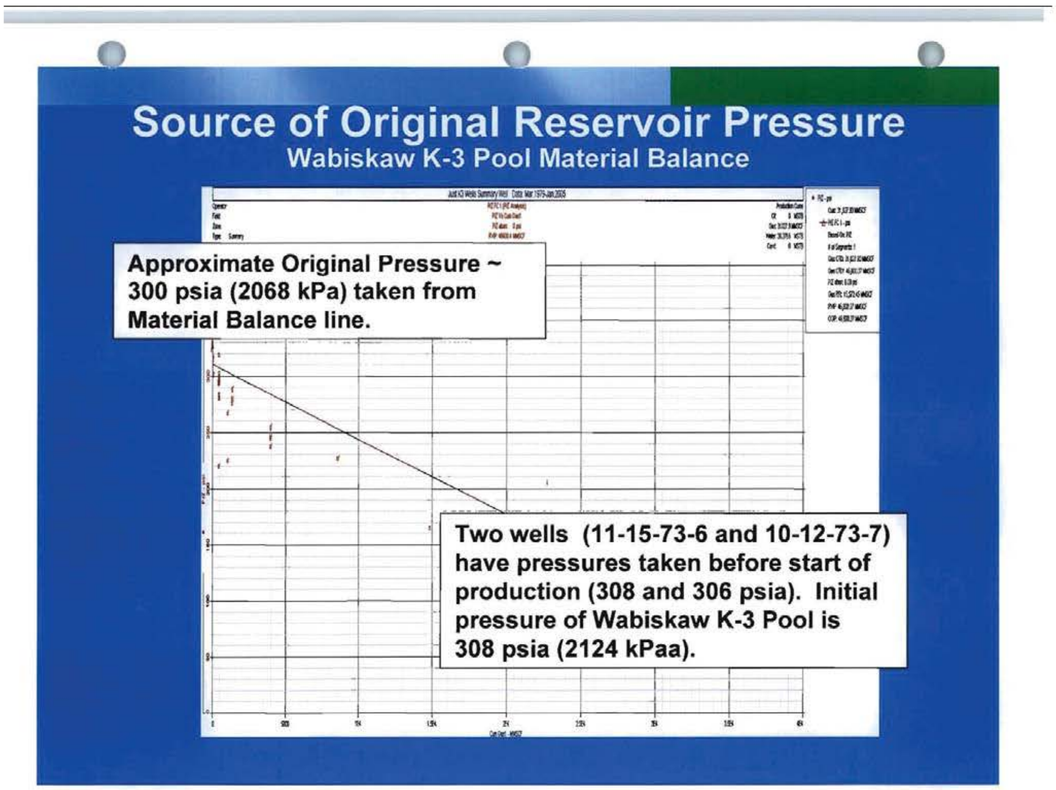
Basic Reservoir Input Parameters

Simulator	CMG STARS
Components	Water, Bitumen, CO_2, CH_4, CO/N_2, Oxygen and Coke
Grid size	**40 m x 40 m x 3 Layers (variable thicknesses)**
Wells	Wabiskaw K3 Pool plus properties up to K1 Pool
Heterogeneity	Homogeneous
Permeability	0.2 to 0.9 D (horizontal); 0.45D (vert)
Porosity	23 to 32% ... 26+% heart of pool
Fluid Saturations Oil Gas Water	Maps from Petrophysical Work 20 to 40% 40 to 60% 20 to 40%
Temperature	12 to 15 °C
Gas Analysis	N_2 (0.44%); CO_2 (0.57%); CH_4 (98.98%)
Initial Reservoir Pressure	2050 kPa
Injected air temp	177°C

K3 Pool – Open boundary Model - Kx

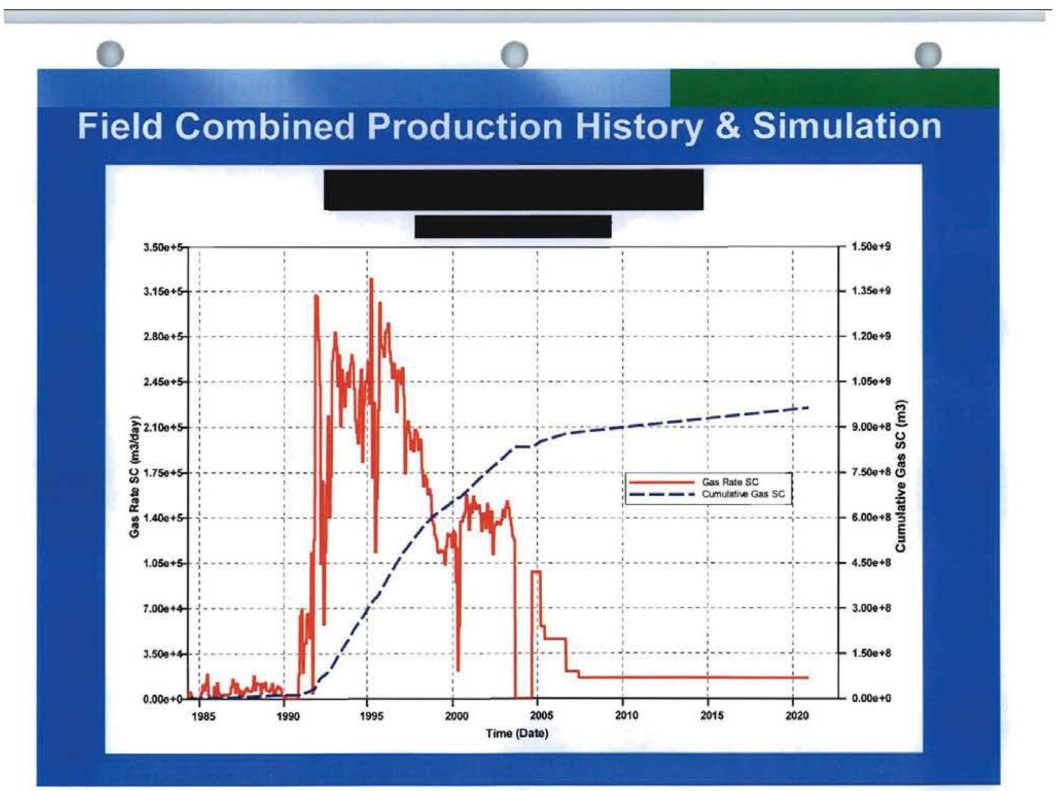


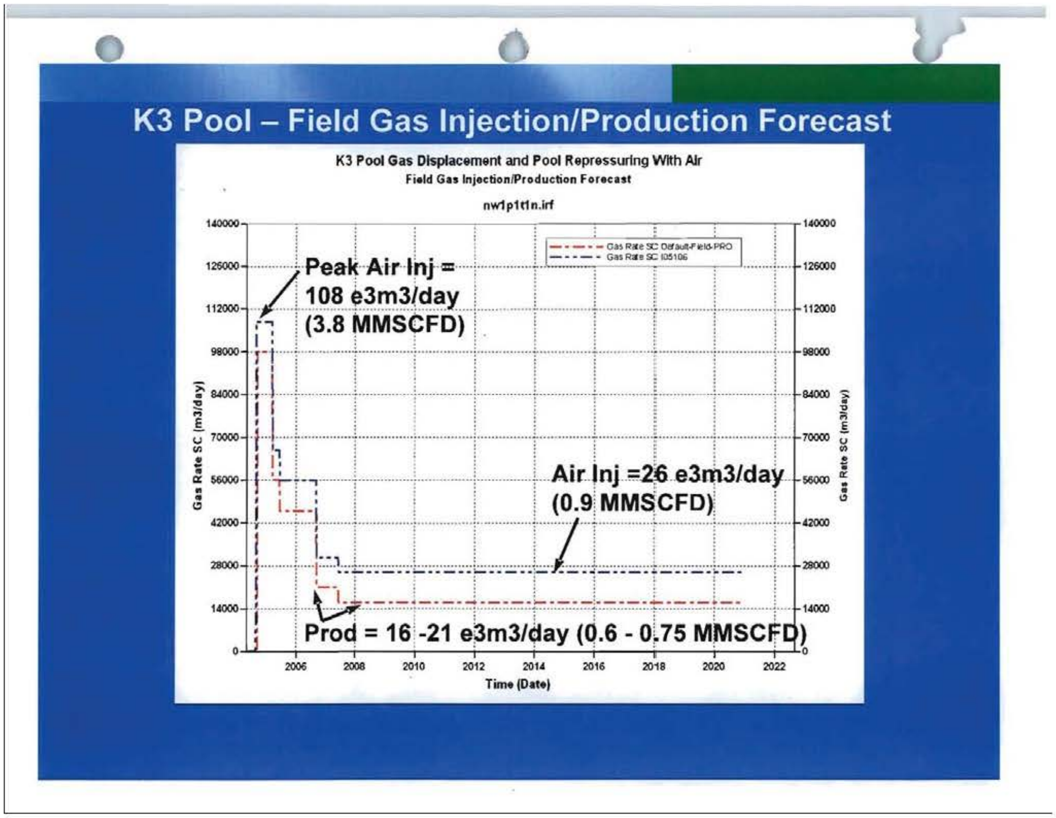

K3 Pool – Open Boundary Model - So
WBSK K3 Gas Pool
Oil Saturation 1984-05-01 K layer: 1
File: building.dat
User: bnzekwu
Date: 2004-06-10
Scale: 1:67863
Y/X: 1.00:1
Axis Units: m
73-7W4
73-6W4
W10147
W10037
501,000 502,000 503,000 504,000 505,000 506,000 507,000 508,000 509,000 510,000 511,000
6,133,000 6,131,000 6,129,000 6,127,000 6,125,000
6,132,000 6,130,000 6,128,000 6,126,000
1.00 0.90 0.80 0.70 0.60 0.50 0.40 0.30 0.20 0.10 0.00
0.00 0.50 1.00 miles
0.00 1.00 2.00 km

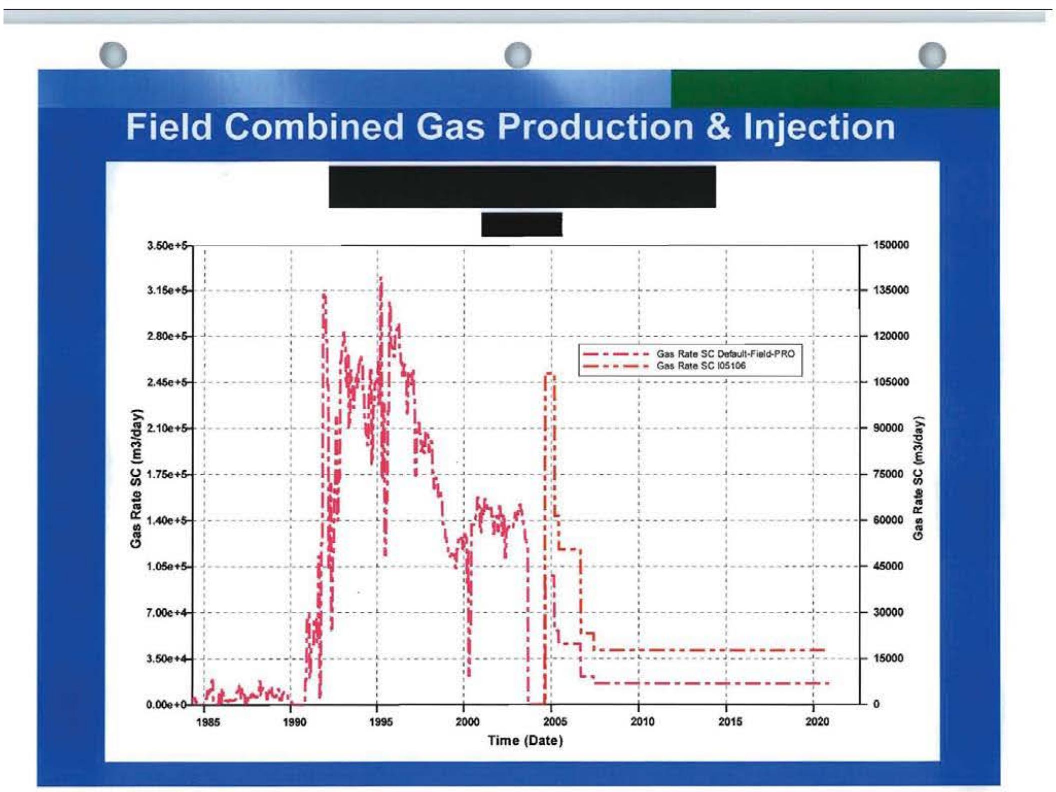

Source of Original Reservoir Pressure
Wabiskaw K-3 Pool Material Balance
Approximate Original Pressure ~ 300 psia (2068 kPa) taken from Material Balance line.
Two wells (11-15-73-6 and 10-12-73-7) have pressures taken before start of production (308 and 306 psia). Initial pressure of Wabiskaw K-3 Pool is 308 psia (2124 kPaa).

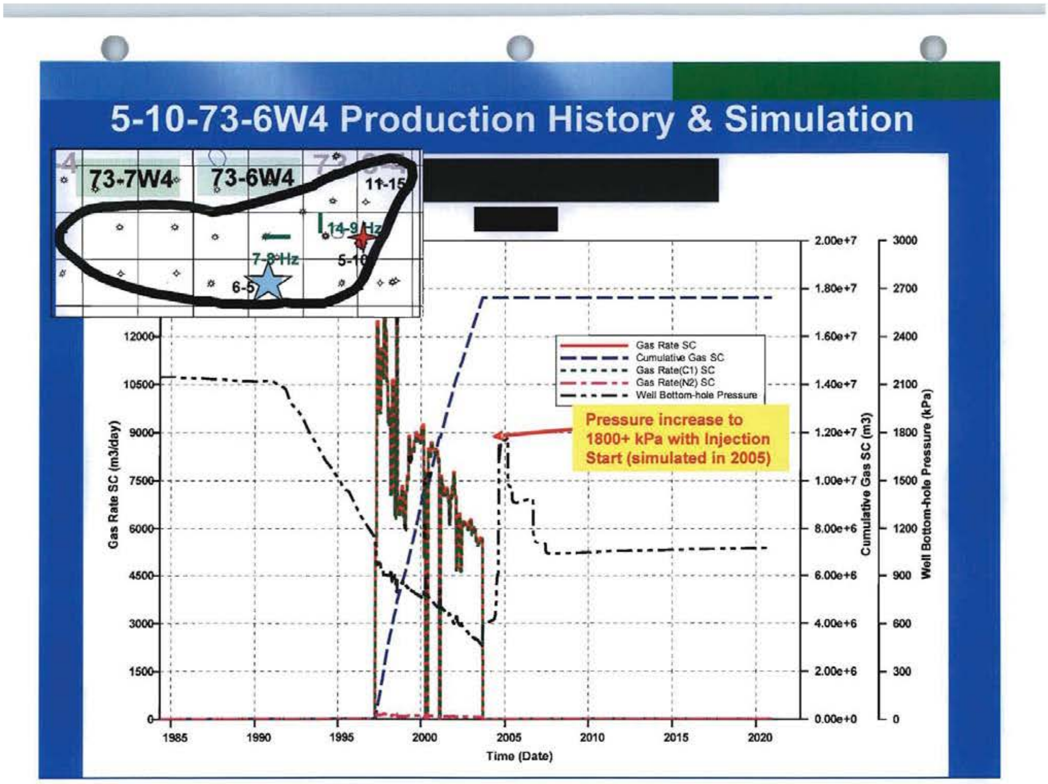
Appendix D: Long Term Simulation


ENCANA
Pre-EnCAID - Long Term Simulation Forecasts
WARNING
Linseed Oil May Cause Spontaneous Combustion

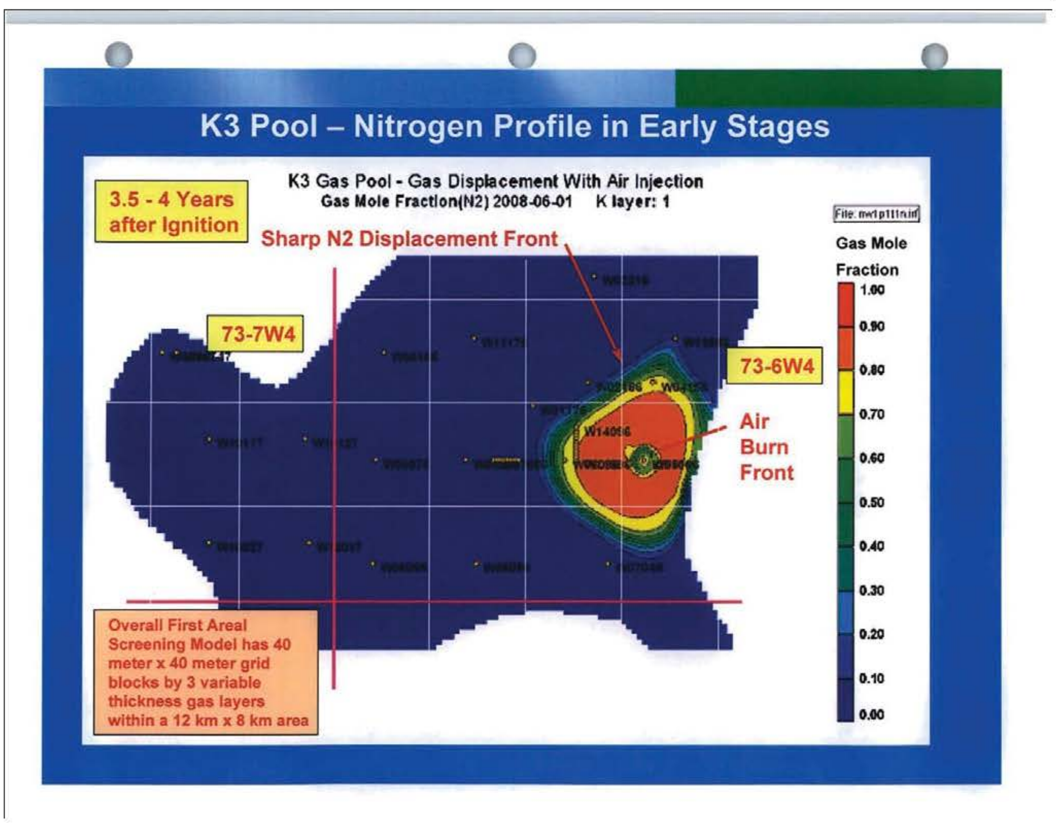

Field Combined Production History & Simulation
[redacted]
Gas Rate SC (m3/day)
Cumulative Gas SC (m3)
Time (Date)
Gas Rate SC
Cumulative Gas SC
3.50e+5
3.15e+5
2.80e+5
2.45e+5
2.10e+5
1.75e+5
1.40e+5
1.05e+5
7.00e+4
3.50e+4
0.00e+0
1.50e+9
1.35e+9
1.20e+9
1.05e+9
9.00e+8
7.50e+8
6.00e+8
4.50e+8
3.00e+8
1.50e+8
0.00e+0
1985
1990
1995
2000
2005
2010
2015
2020


K3 Pool – Field Gas Injection/Production Forecast
K3 Pool Gas Displacement and Pool Repressuring With Air
Field Gas Injection/Production Forecast
nw1p1t1n.irf
Gas Rate SC Default-Field-PRO
Gas Rate SC I05106
Peak Air Inj = 108 e3m3/day (3.8 MMSCFD)
Air Inj =26 e3m3/day (0.9 MMSCFD)
Prod = 16 -21 e3m3/day (0.6 - 0.75 MMSCFD)
Gas Rate SC (m3/day)
Time (Date)

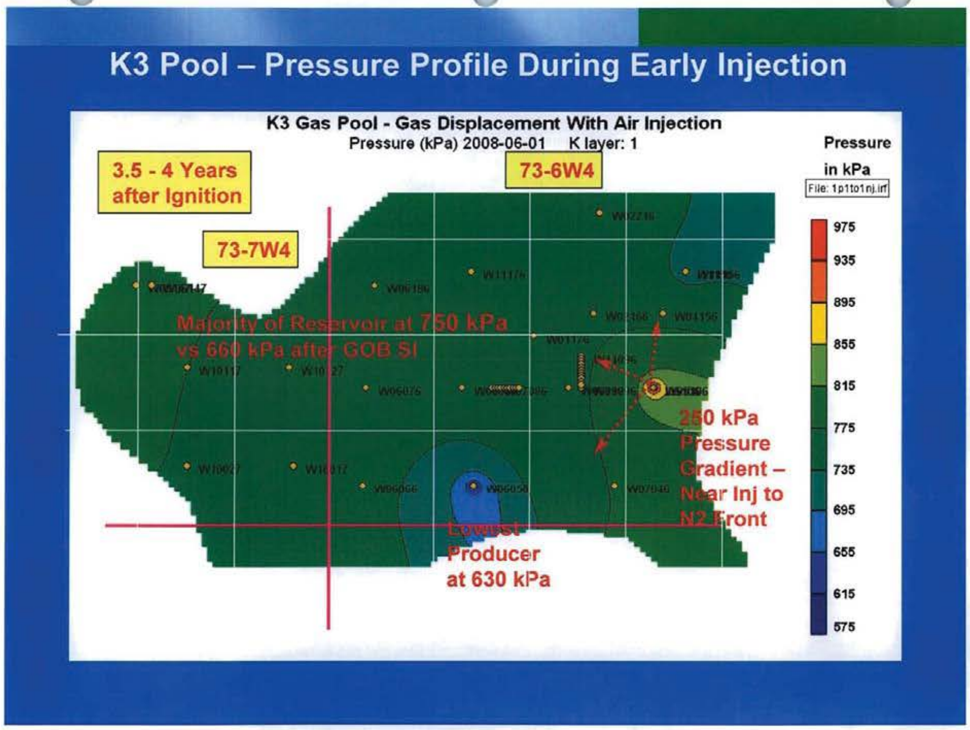

Field Combined Gas Production & Injection
[redacted]
Gas Rate SC Default-Field-PRO
Gas Rate SC I05106
Gas Rate SC (m3/day)
Time (Date)

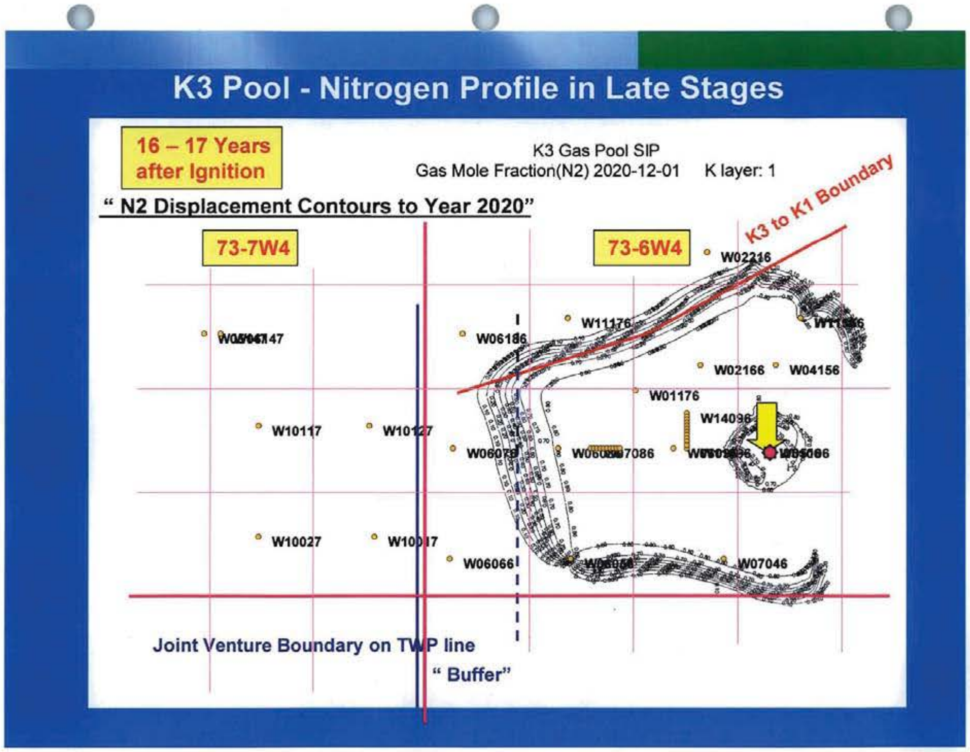


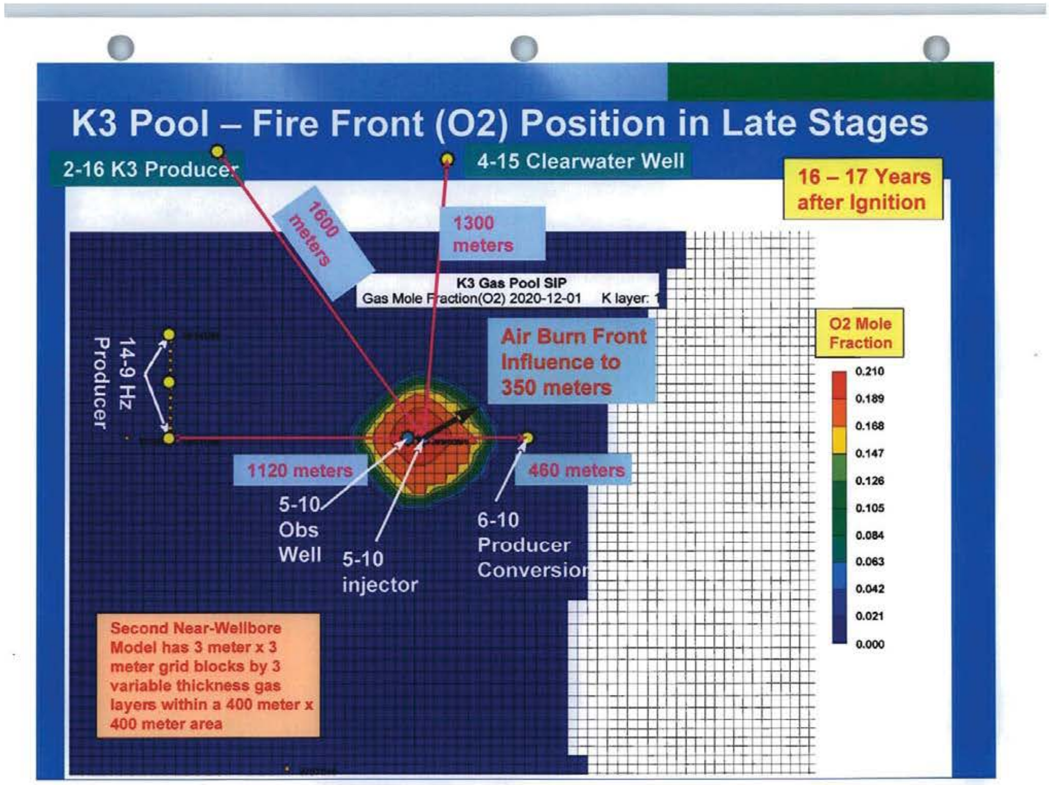
5-10-73-6W4 Production History & Simulation
73-7W4
73-6W4
11-15
14-9 Hz
7-8 Hz
5-10
6-5
[redacted]
Gas Rate SC
Cumulative Gas SC
Gas Rate(C1) SC
Gas Rate(N2) SC
Well Bottom-hole Pressure
Pressure increase to
1800+ kPa with Injection
Start (simulated in 2005)
Gas Rate SC (m3/day)
Cumulative Gas SC (m3)
Well Bottom-hole Pressure (kPa)
Time (Date)

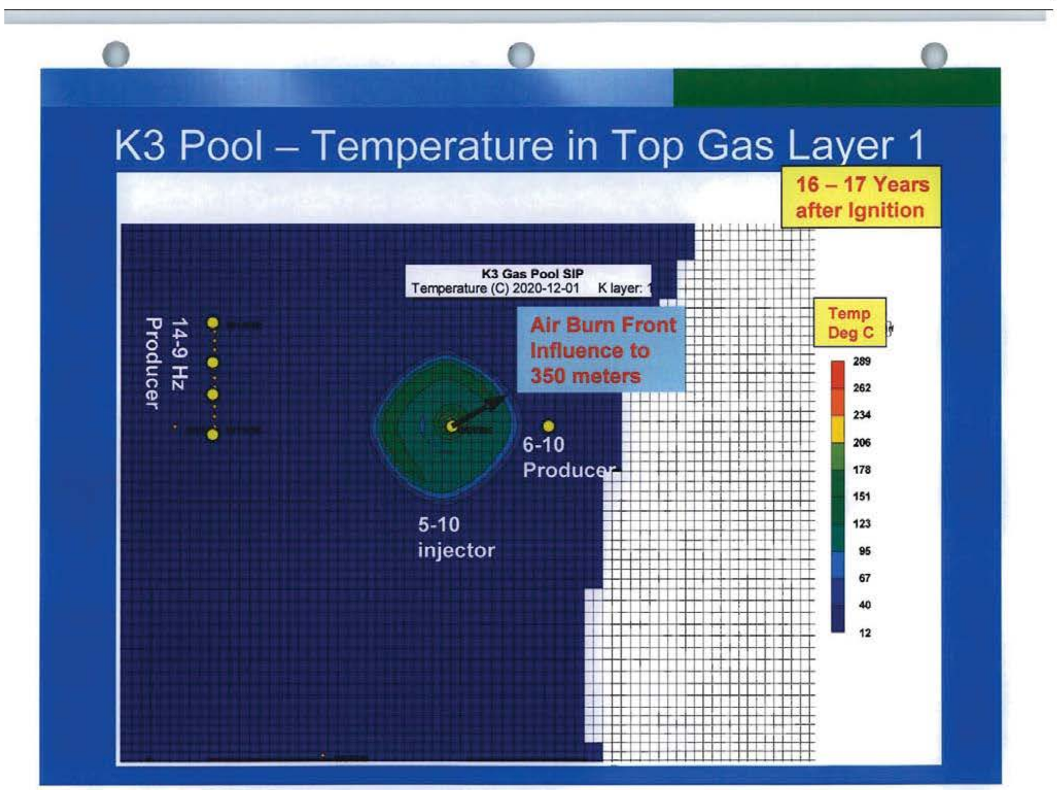


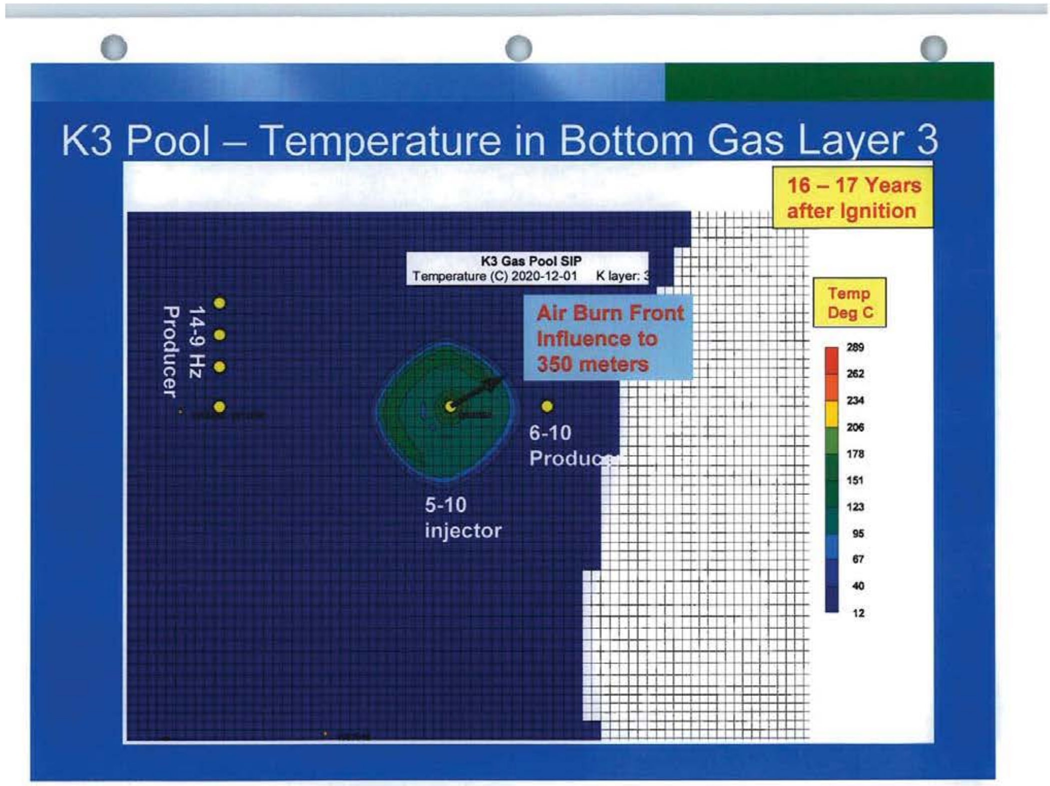
K3 Pool – Nitrogen Profile in Early Stages
K3 Gas Pool - Gas Displacement With Air Injection
Gas Mole Fraction(N2) 2008-06-01 K layer: 1
3.5 - 4 Years
after Ignition
Sharp N2 Displacement Front
73-7W4
73-6W4
Air
Burn
Front
Gas Mole
Fraction
Overall First Areal
Screening Model has 40
meter x 40 meter grid
blocks by 3 variable
thickness gas layers
within a 12 km x 8 km area


K3 Pool – Pressure Profile During Early Injection
K3 Gas Pool - Gas Displacement With Air Injection
Pressure (kPa) 2008-06-01 K layer: 1
3.5 - 4 Years after Ignition
73-6W4
73-7W4
Pressure in kPa
Majority of Reservoir at 750 kPa vs 660 kPa after GOB SI
250 kPa Pressure Gradient – Near Inj to N2 Front
Lowest Producer at 630 kPa
975
935
895
855
815
775
735
695
655
615
575

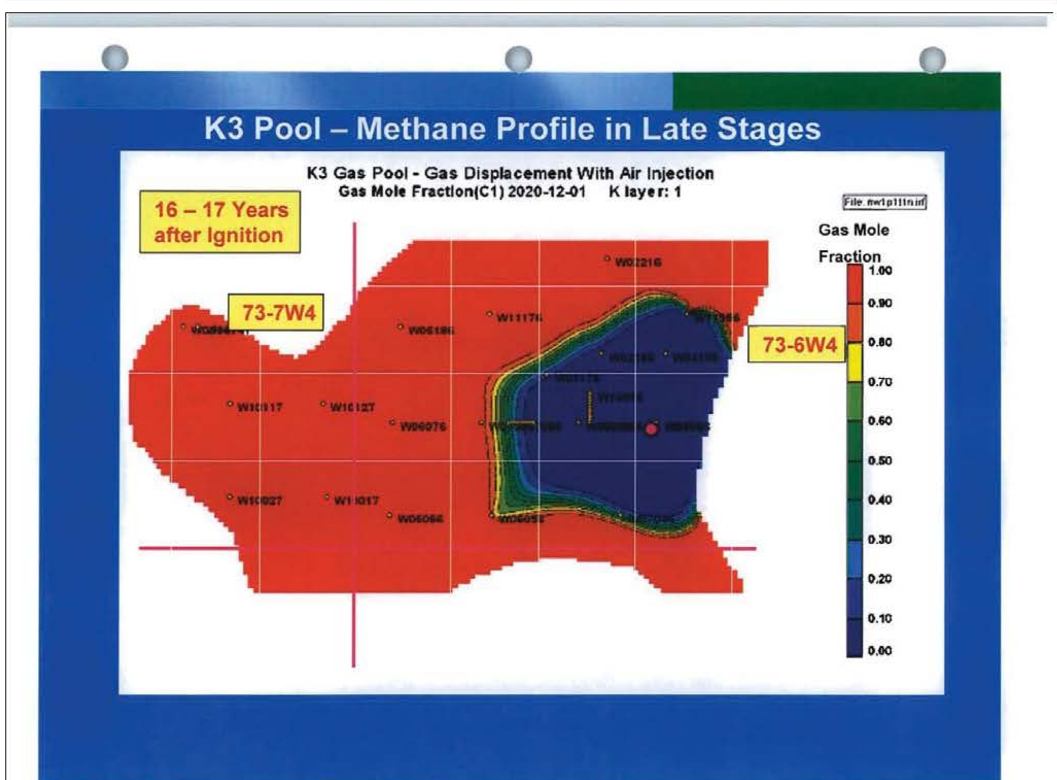

K3 Pool - Nitrogen Profile in Late Stages
16 – 17 Years after Ignition
K3 Gas Pool SIP
Gas Mole Fraction(N2) 2020-12-01 K layer: 1
" N2 Displacement Contours to Year 2020"
K3 to K1 Boundary
73-7W4
73-6W4
W02216
W11176
W06186
W02166
W04156
W01176
W10117
W14096
W06076
W10027
W06066
W07046
Joint Venture Boundary on TWP line
" Buffer"


K3 Pool – Fire Front (O2) Position in Late Stages
2-16 K3 Producer
4-15 Clearwater Well
16 – 17 Years after Ignition
1600 meters
1300 meters
K3 Gas Pool SIP
Gas Mole Fraction(O2) 2020-12-01 K layer: 1
O2 Mole Fraction
0.210
0.189
0.168
0.147
0.126
0.105
0.084
0.063
0.042
0.021
0.000
14-9 Hz Producer
Air Burn Front Influence to 350 meters
1120 meters
460 meters
5-10 Obs Well
5-10 injector
6-10 Producer Conversion
Second Near-Wellbore Model has 3 meter x 3 meter grid blocks by 3 variable thickness gas layers within a 400 meter x 400 meter area

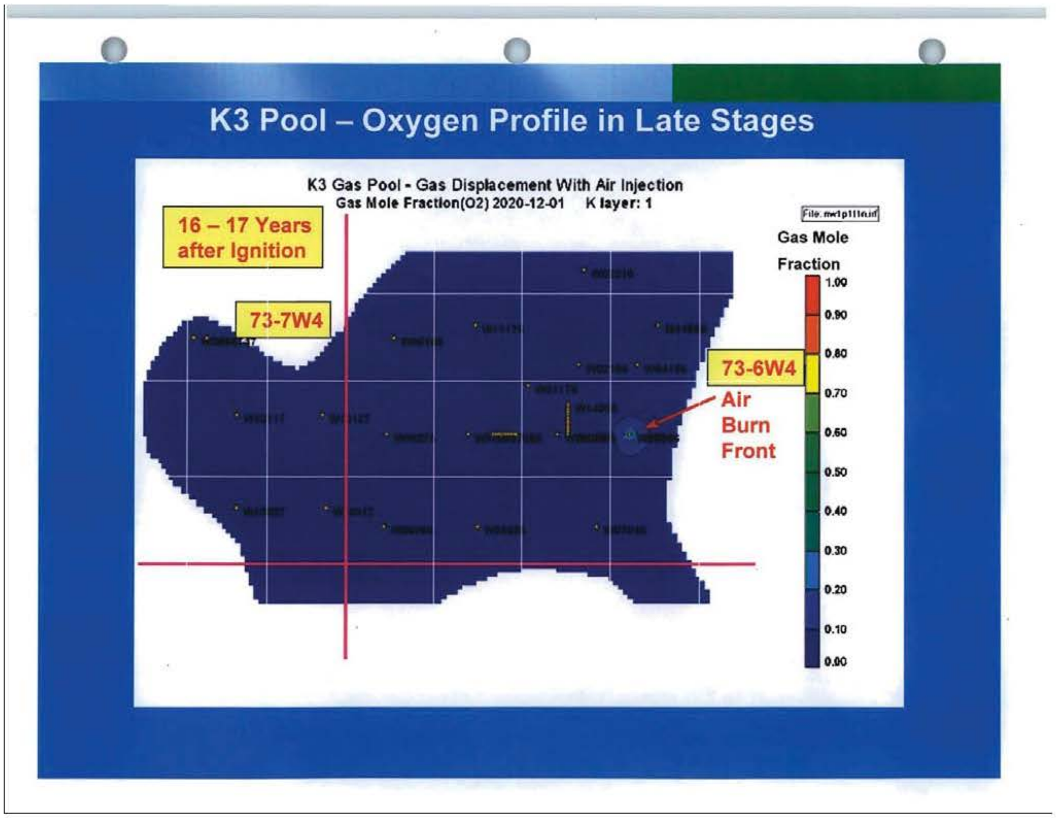

K3 Pool – Temperature in Top Gas Layer 1
16 – 17 Years after Ignition
K3 Gas Pool SIP
Temperature (C) 2020-12-01 K layer: 1
Temp Deg C
289
262
234
206
178
151
123
95
67
40
12
14-9 Hz Producer
Air Burn Front Influence to 350 meters
6-10 Producer
5-10 injector

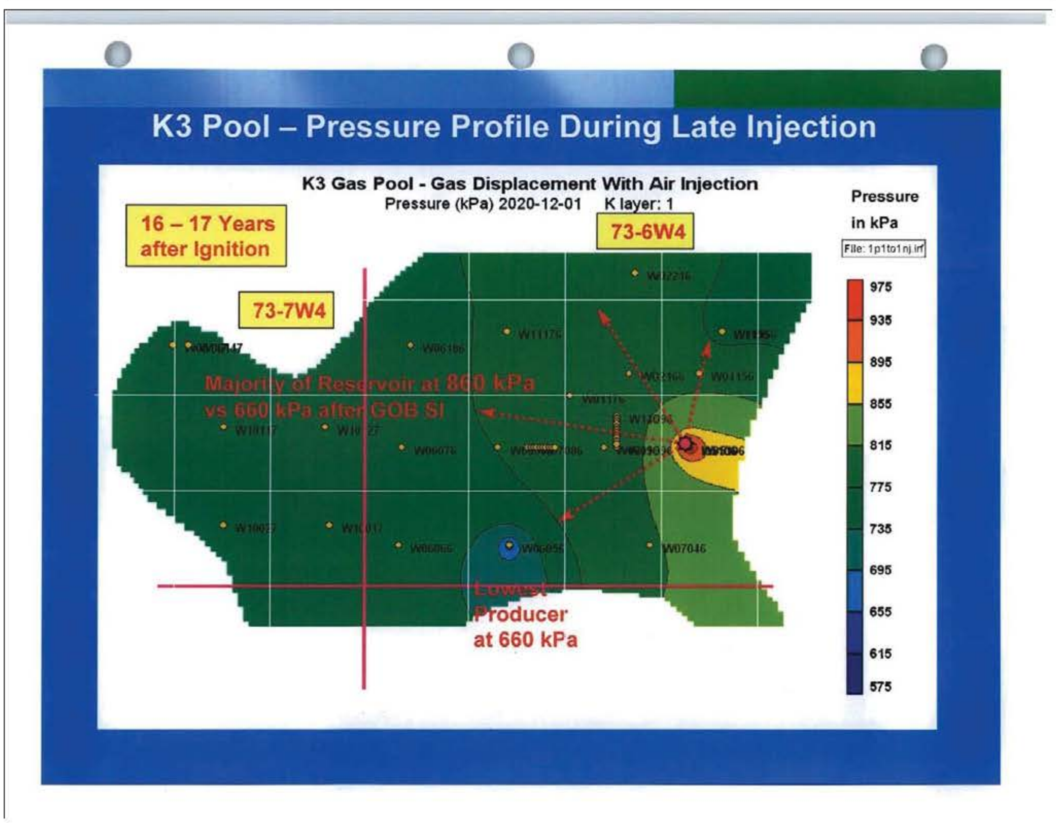


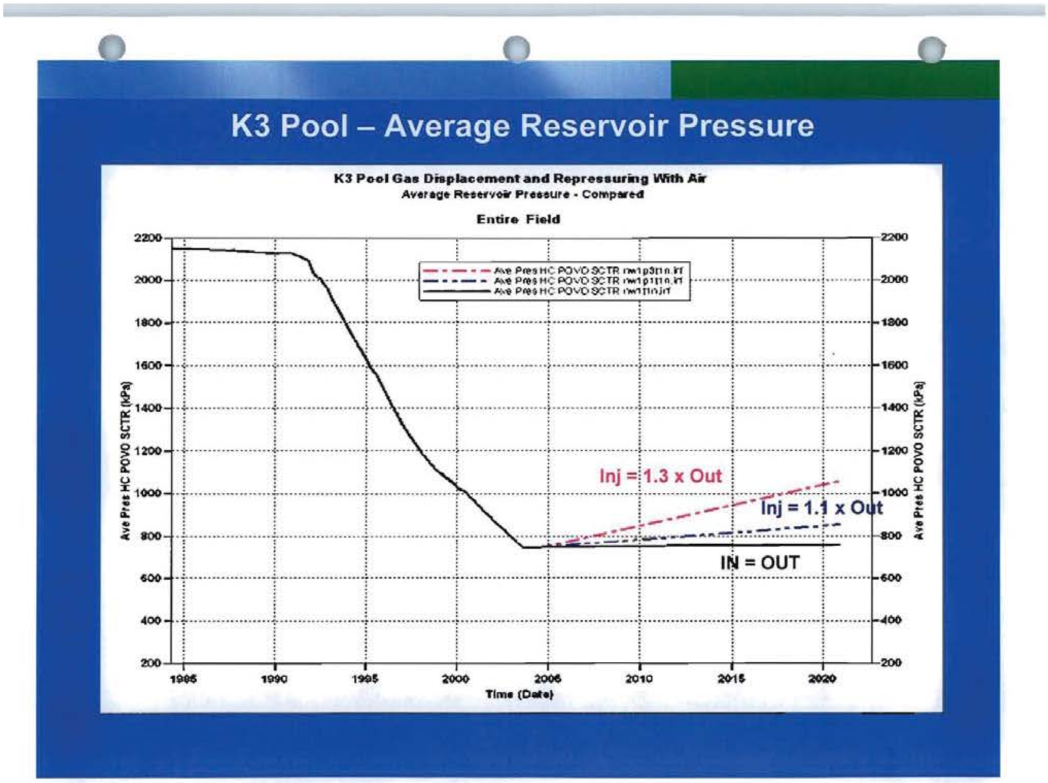
K3 Pool – Temperature in Bottom Gas Layer 3
16 – 17 Years after Ignition
K3 Gas Pool SIP
Temperature (C) 2020-12-01 K layer: 3
Air Burn Front Influence to 350 meters
14-9 Hz Producer
6-10 Producer
5-10 injector
Temp Deg C
289
262
234
206
178
151
123
95
67
40
12

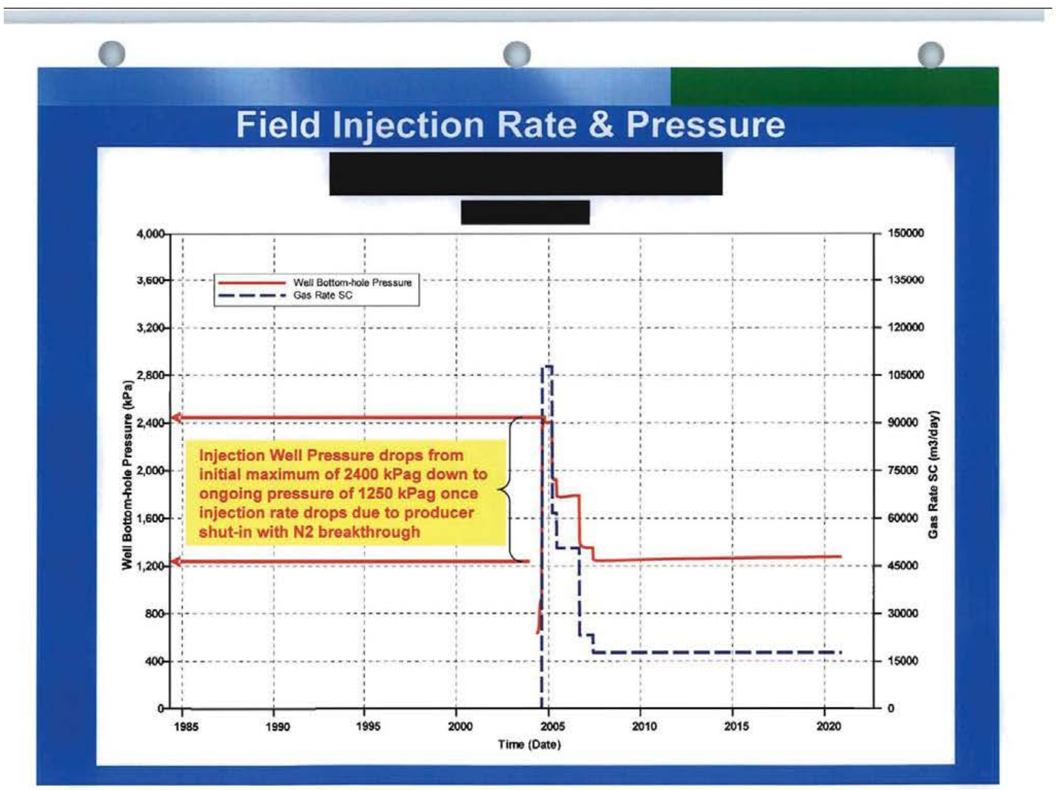


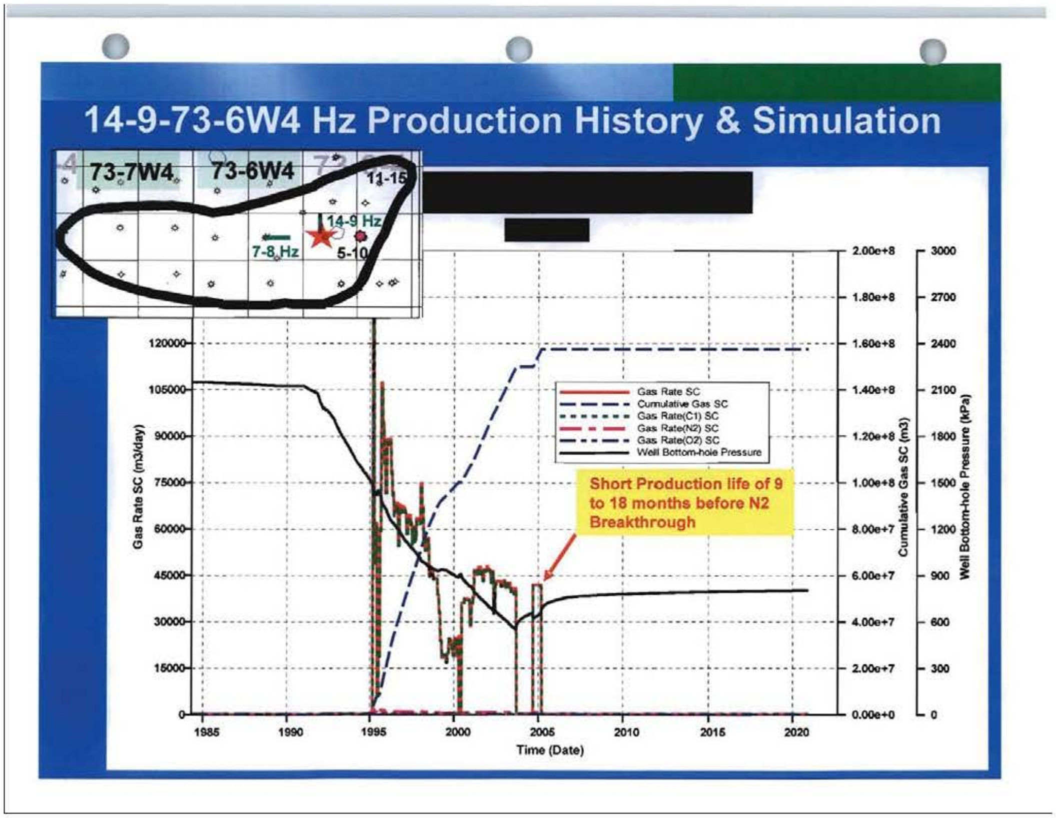
K3 Pool – Methane Profile in Late Stages
K3 Gas Pool - Gas Displacement With Air Injection
Gas Mole Fraction(C1) 2020-12-01 K layer: 1
16 – 17 Years after Ignition
73-7W4
73-6W4
Gas Mole Fraction
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00

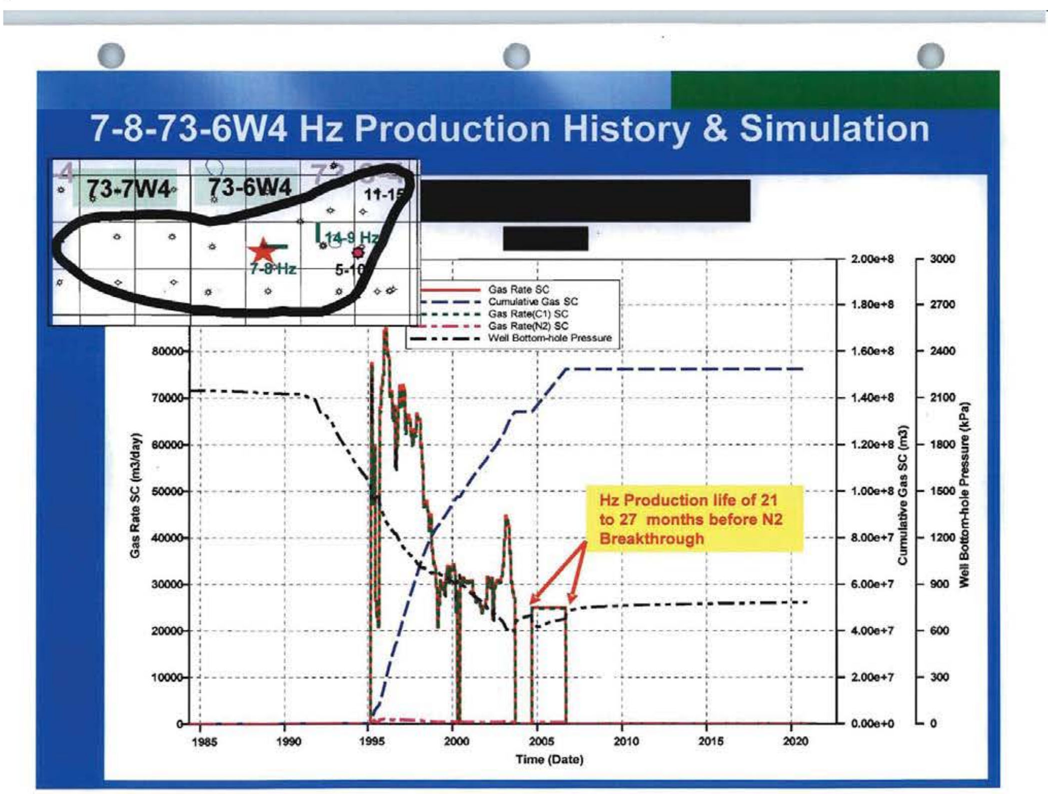

K3 Pool – Oxygen Profile in Late Stages
K3 Gas Pool - Gas Displacement With Air Injection
Gas Mole Fraction(O2) 2020-12-01 K layer: 1
16 – 17 Years after Ignition
73-7W4
73-6W4
Air Burn Front
Gas Mole Fraction
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00

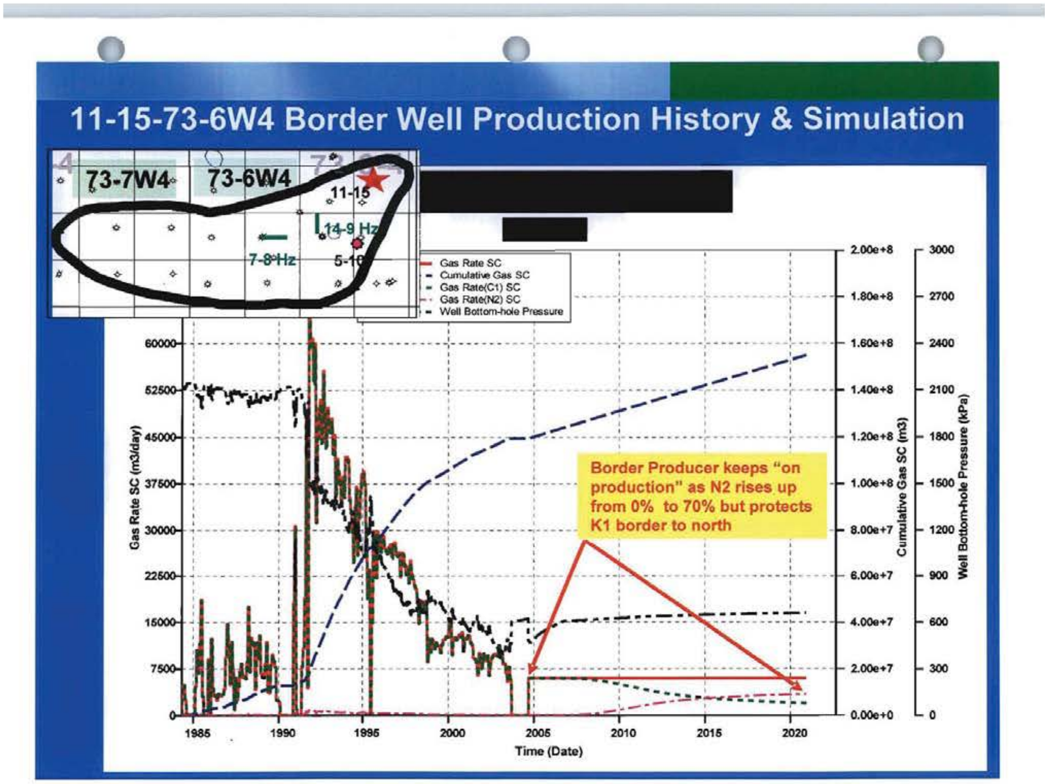

K3 Pool – Pressure Profile During Late Injection
K3 Gas Pool - Gas Displacement With Air Injection
Pressure (kPa) 2020-12-01 K layer: 1
16 – 17 Years after Ignition
73-6W4
73-7W4
Majority of Reservoir at 860 kPa vs 660 kPa after GOB SI
Lowest Producer at 660 kPa
Pressure in kPa
File: 1p1to1nj.irf
975
935
895
855
815
775
735
695
655
615
575

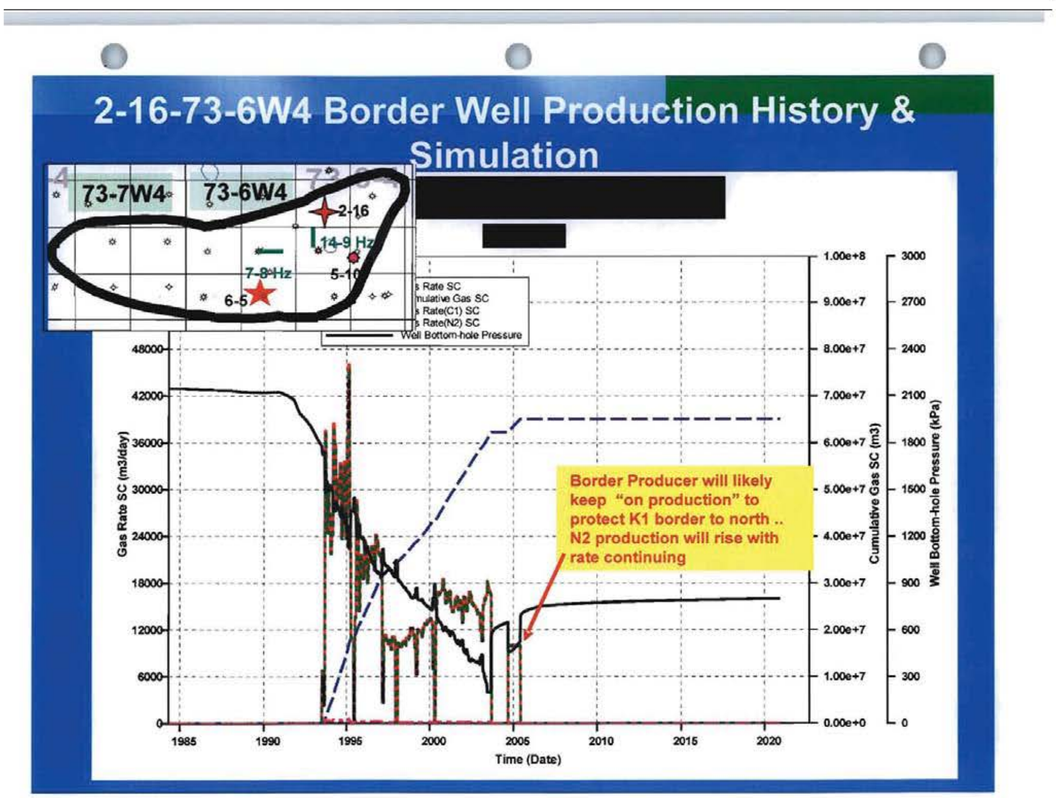

K3 Pool – Average Reservoir Pressure
K3 Pool Gas Displacement and Repressuring With Air
Average Reservoir Pressure - Compared
Entire Field
Ave Pres HC POVO SCTR (kPa)
Inj = 1.3 x Out
Inj = 1.1 x Out
IN = OUT
Time (Date)

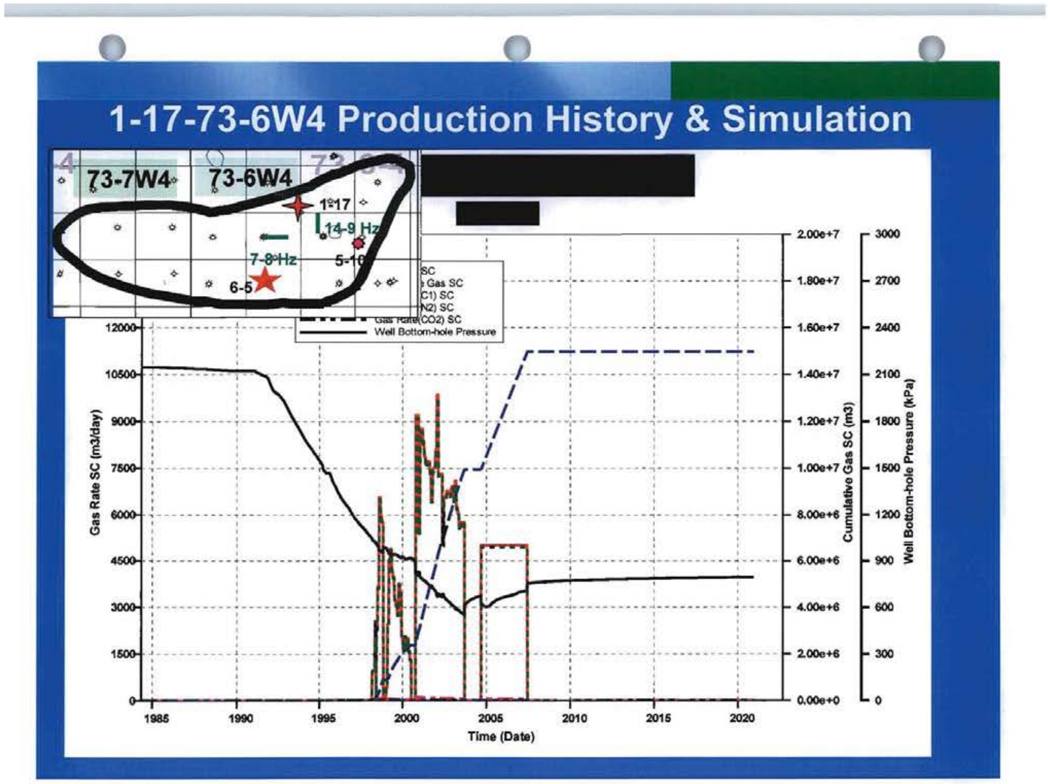

Field Injection Rate & Pressure
[redacted]
[redacted]
Well Bottom-hole Pressure
Gas Rate SC
Well Bottom-hole Pressure (kPa)
Gas Rate SC (m3/day)
Injection Well Pressure drops from initial maximum of 2400 kPag down to ongoing pressure of 1250 kPag once injection rate drops due to producer shut-in with N2 breakthrough
Time (Date)

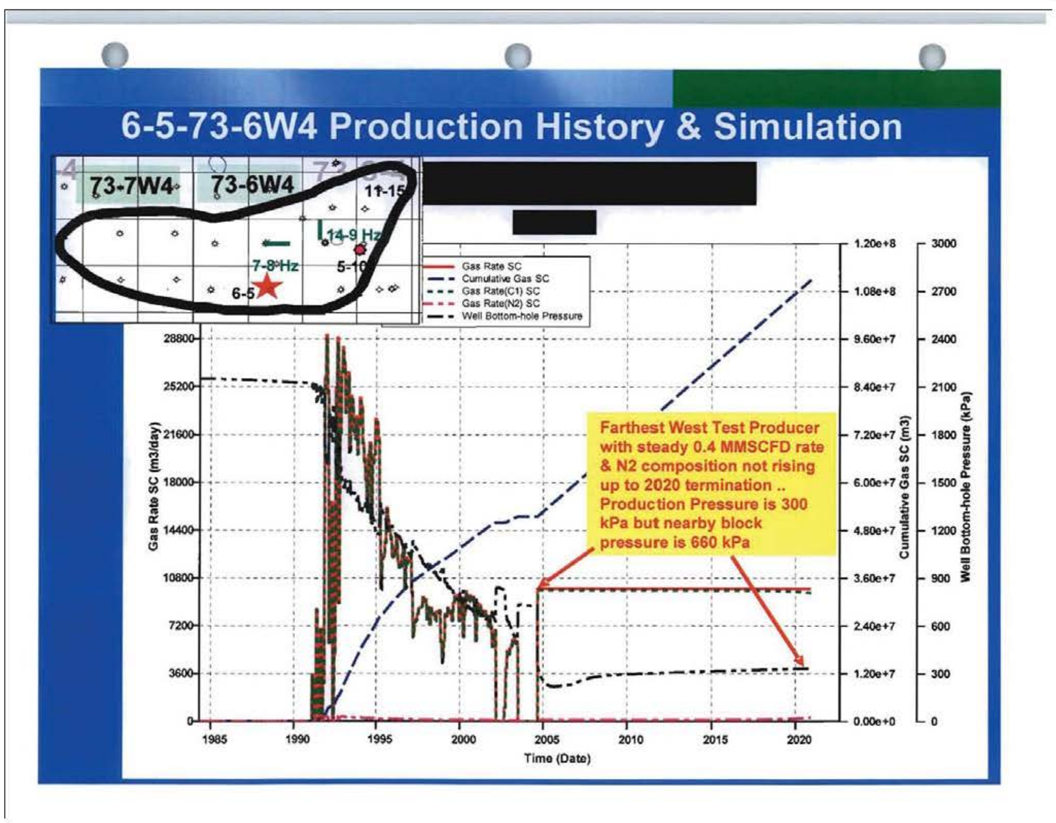

14-9-73-6W4 Hz Production History & Simulation
73-7W4
73-6W4
11-15
14-9 Hz
7-8 Hz
5-10
[redacted]
Gas Rate SC (m3/day)
Cumulative Gas SC (m3)
Well Bottom-hole Pressure (kPa)
Time (Date)
Gas Rate SC
Cumulative Gas SC
Gas Rate(C1) SC
Gas Rate(N2) SC
Gas Rate(O2) SC
Well Bottom-hole Pressure
Short Production life of 9 to 18 months before N2 Breakthrough

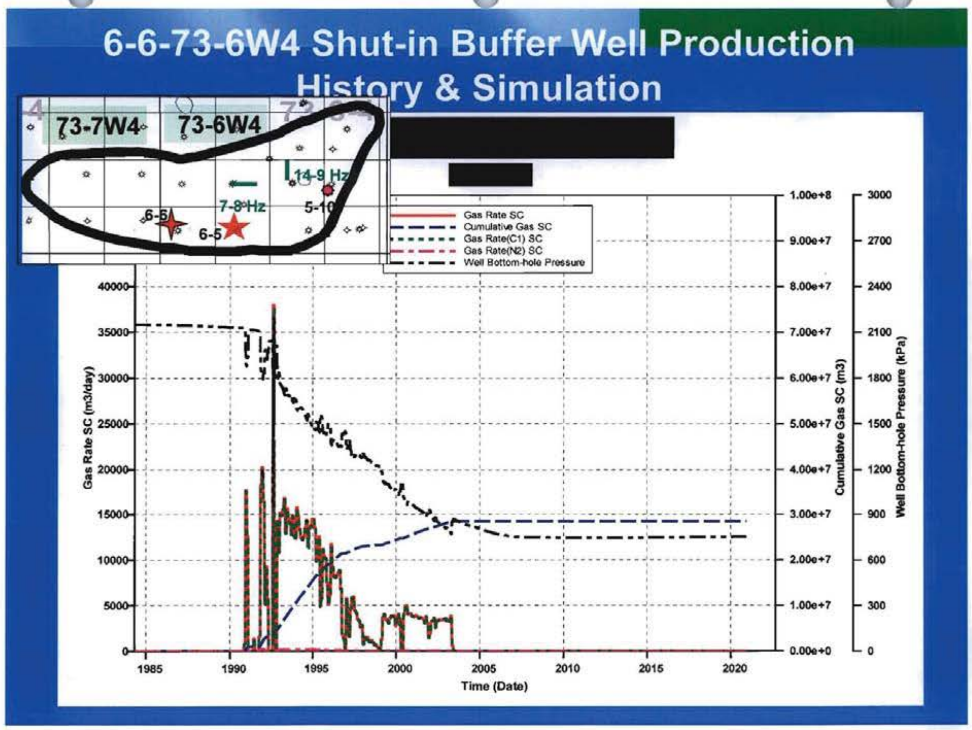

7-8-73-6W4 Hz Production History & Simulation
73-7W4
73-6W4
11-15
14-9 Hz
7-8 Hz
5-10
[redacted]
Gas Rate SC (m3/day)
Cumulative Gas SC (m3)
Well Bottom-hole Pressure (kPa)
Time (Date)
Gas Rate SC
Cumulative Gas SC
Gas Rate(C1) SC
Gas Rate(N2) SC
Well Bottom-hole Pressure
Hz Production life of 21 to 27 months before N2 Breakthrough

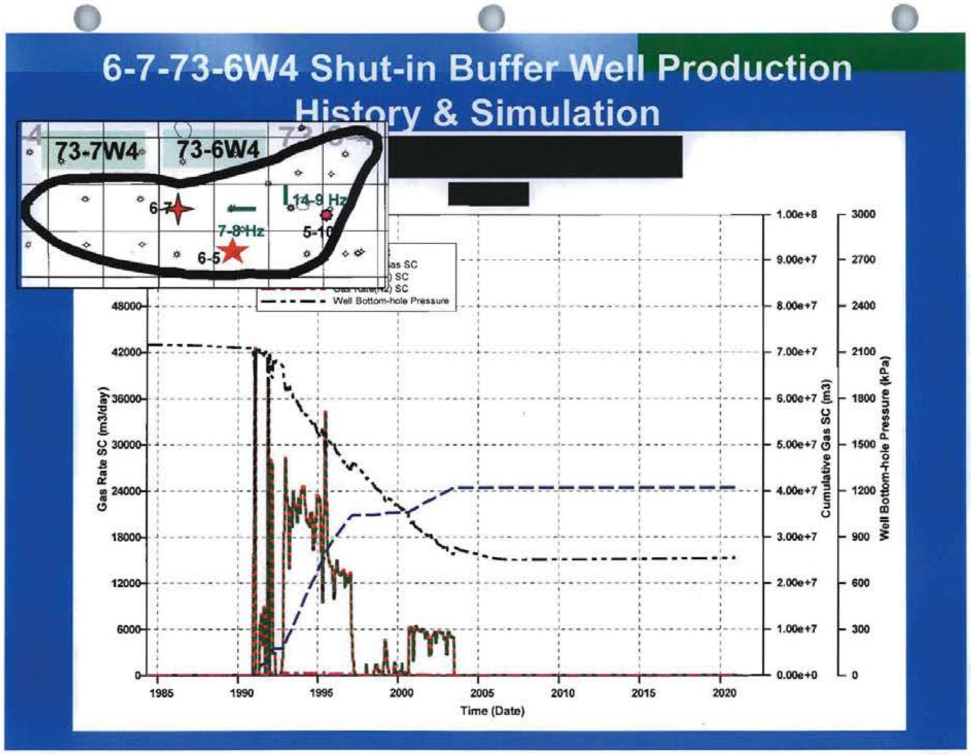

11-15-73-6W4 Border Well Production History & Simulation
73-7W4
73-6W4
11-15
14-9 Hz
7-8 Hz
5-10
[redacted]
Gas Rate SC
Cumulative Gas SC
Gas Rate(C1) SC
Gas Rate(N2) SC
Well Bottom-hole Pressure
Gas Rate SC (m3/day)
Cumulative Gas SC (m3)
Well Bottom-hole Pressure (kPa)
Time (Date)
Border Producer keeps "on production" as N2 rises up from 0% to 70% but protects K1 border to north

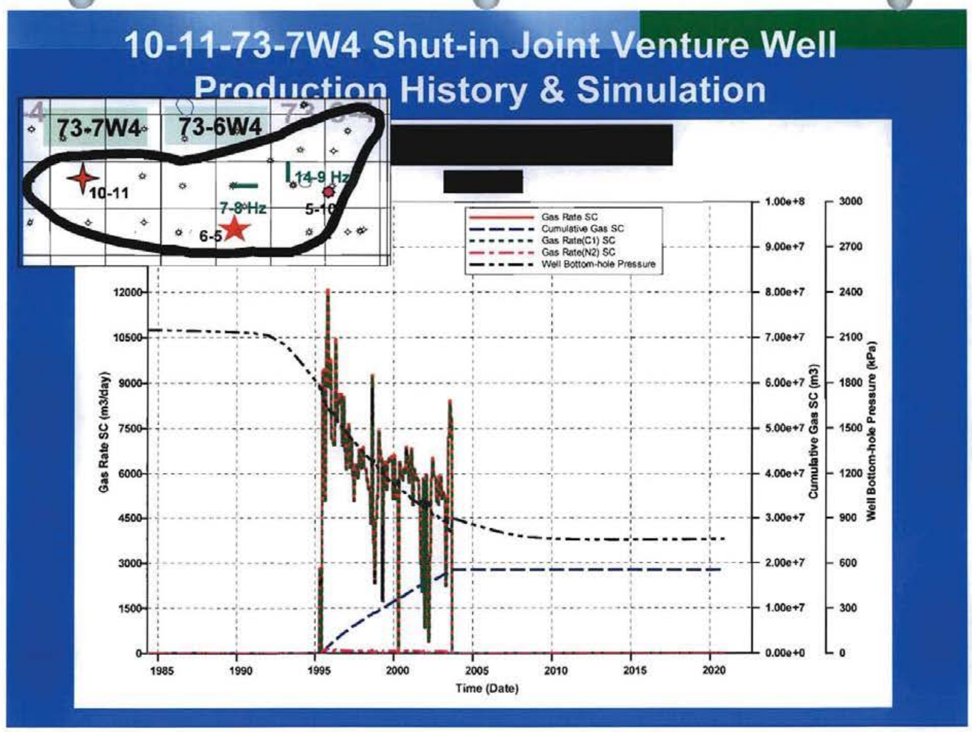

2-16-73-6W4 Border Well Production History & Simulation
73-7W4
73-6W4
2-16
14-9 Hz
7-8 Hz
5-10
6-5
[redacted]
Well Bottom-hole Pressure
Gas Rate SC (m3/day)
Cumulative Gas SC (m3)
Well Bottom-hole Pressure (kPa)
Time (Date)
Border Producer will likely keep "on production" to protect K1 border to north .. N2 production will rise with rate continuing

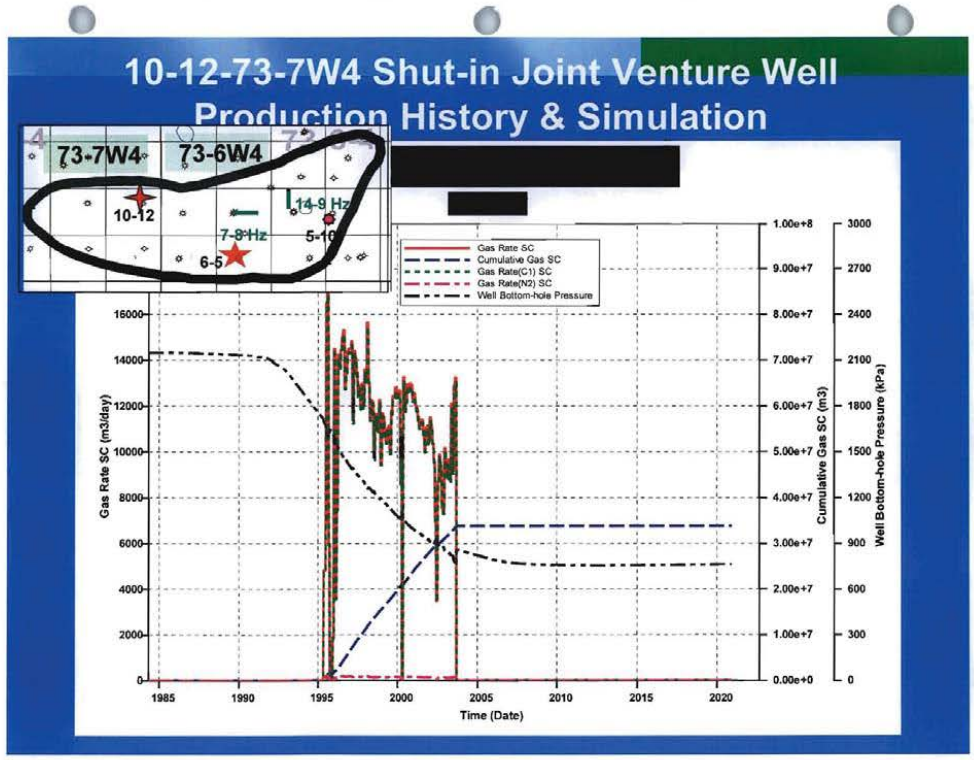

1-17-73-6W4 Production History & Simulation
73-7W4
73-6W4
1-17
14-9 Hz
7-8 Hz
5-10
6-5
[redacted]
Well Bottom-hole Pressure
Gas Rate SC (m3/day)
Cumulative Gas SC (m3)
Well Bottom-hole Pressure (kPa)
Time (Date)

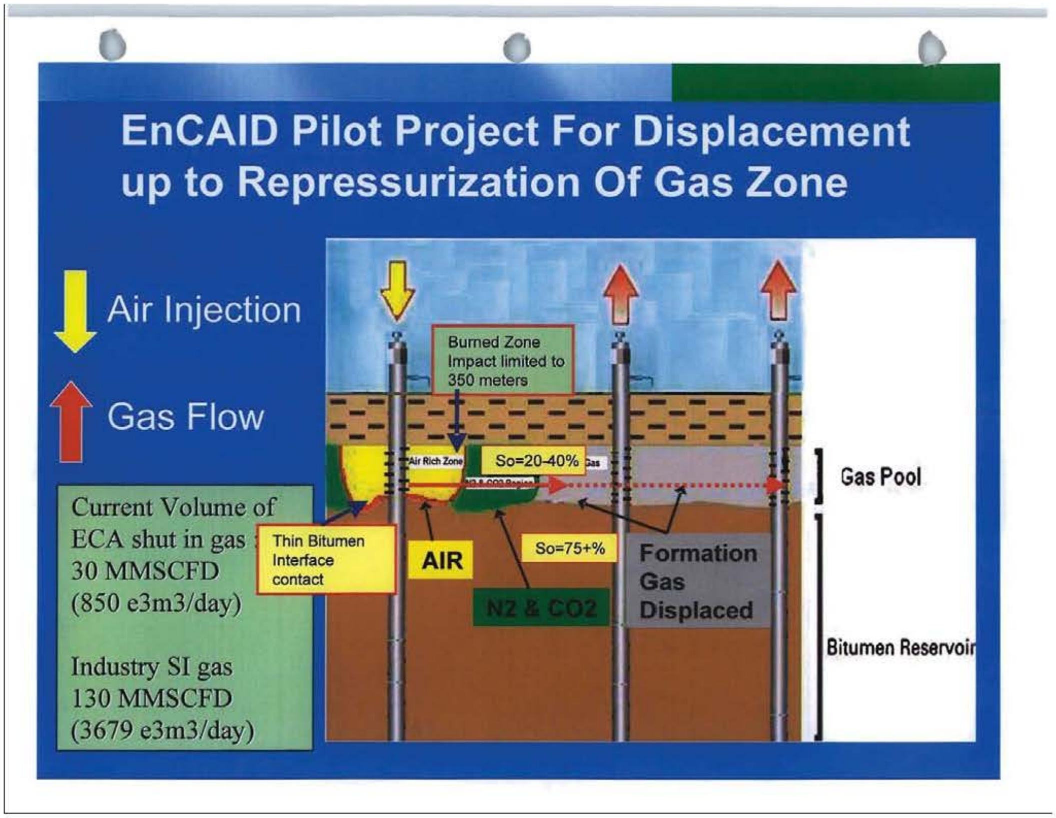

6-5-73-6W4 Production History & Simulation
73-7W4
73-6W4
11-15
14-9 Hz
7-8 Hz
5-10
6-5
[redacted]
Gas Rate SC
Cumulative Gas SC
Gas Rate(C1) SC
Gas Rate(N2) SC
Well Bottom-hole Pressure
Farthest West Test Producer with steady 0.4 MMSCFD rate & N2 composition not rising up to 2020 termination .. Production Pressure is 300 kPa but nearby block pressure is 660 kPa
Gas Rate SC (m3/day)
Cumulative Gas SC (m3)
Well Bottom-hole Pressure (kPa)
Time (Date)


6-6-73-6W4 Shut-in Buffer Well Production
History & Simulation
73-7W4
73-6W4
14-9 Hz
7-8 Hz
5-10
6-6
6-5
[redacted]
Gas Rate SC
Cumulative Gas SC
Gas Rate(C1) SC
Gas Rate(N2) SC
Well Bottom-hole Pressure
Gas Rate SC (m3/day)
Cumulative Gas SC (m3)
Well Bottom-hole Pressure (kPa)
Time (Date)


6-7-73-6W4 Shut-in Buffer Well Production
History & Simulation
73-7W4
73-6W4
14-9 Hz
7-8 Hz
5-10
6-7
6-5
[redacted]
Well Bottom-hole Pressure
Gas Rate SC (m3/day)
Cumulative Gas SC (m3)
Well Bottom-hole Pressure (kPa)
Time (Date)


10-11-73-7W4 Shut-in Joint Venture Well
Production History & Simulation
[redacted]
73-7W4
73-6W4
10-11
7-8 Hz
14-9 Hz
5-10
6-5
Gas Rate SC
Cumulative Gas SC
Gas Rate(C1) SC
Gas Rate(N2) SC
Well Bottom-hole Pressure
Gas Rate SC (m3/day)
Cumulative Gas SC (m3)
Well Bottom-hole Pressure (kPa)
Time (Date)


10-12-73-7W4 Shut-in Joint Venture Well
Production History & Simulation
[redacted]
73-7W4
73-6W4
10-12
7-8 Hz
14-9 Hz
5-10
6-5
Gas Rate SC
Cumulative Gas SC
Gas Rate(C1) SC
Gas Rate(N2) SC
Well Bottom-hole Pressure
Gas Rate SC (m3/day)
Cumulative Gas SC (m3)
Well Bottom-hole Pressure (kPa)
Time (Date)



EnCAID Pilot Project For Displacement up to Repressurization Of Gas Zone
Air Injection
Gas Flow
Current Volume of ECA shut in gas : 30 MMSCFD (850 e3m3/day)
Industry SI gas 130 MMSCFD (3679 e3m3/day)
Burned Zone Impact limited to 350 meters
Air Rich Zone
So=20-40%
Gas Pool
Thin Bitumen Interface contact
AIR
So=75+%
Formation Gas Displaced
N2 & CO2
Bitumen Reservoir