Innovative Energy Technologies Program
Approval 03-055
Taber Glauconitic K Pool

Alkaline-Surfactant-Polymer Flood Using Surfactants Derived from Renewable Resources

Crowsnest ASP Flood

2009 Annual Report
June 25, 2010

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1. Executive Summary

Husky Oil Operations Limited implemented the first field-wide Alkaline-Surfactant-Polymer (ASP) Flood using surfactants derived from renewable resources on January 23, 2008.

The co-surfactants are a blend of sodium lignosulfonate (lignin) and alkyl polyglycosides (APG). Lignin is a natural polymer that binds a tree together. Lignosulfonates can act as both a binder and a dispersant and these qualities can enhance the efficiency of ASP systems. APGs are an agricultural crop based combination of fatty alcohols and glucose, mostly used in personal care formulations, cleaners, and agricultural formulations, and are readily biodegradable.

Incremental oil production is expected to be 762 10^3m^3 from the Taber Glauconitic K pool, an incremental oil recovery factor equal to 15.0% of the original-oil-in-place (OOIP). Ultimate production is estimated to be 10% higher using green chemistry based surfactants than the ASP system using conventional surfactants.

Pool oil production was 26 m^3/d with an oil cut of 0.9% when ASP injection began in January 2008 and in April 2010 oil production was 127 m^3/d with a 5.3% oil cut. Total incremental oil production above the base decline at the end of April 2010 was 22 10^3m^3 or 0.4% OOIP incremental recovery factor.

2. Summary Project Status Report

Key Team Members

Key team members are shown in Table 1. They are unchanged from 2008.

Table 1: *Key Team Members*

Name	Title	Expertise Added
Ran Lin	Reservoir Engineering Specialist	Reservoir Engineering
Lee McInnis	Staff Reservoir Engineer	Reservoir Engineering
Tyler Ellis-Toddington	Engineering Specialist	Project Manager
David Grawbarger	Geological Specialist	Geology
Gilbert Chen	Staff Geologist	ASP Chemical Interactions
Krystle Drover	Production Engineer	Production Engineering
Rick Reti	Field Foreman	Operations

Timeline

The chronology of major activities and operations conducted as part of the Crowsnest ASP project prior to 2009 was included in previous reports. Table 2 lists significant activities in 2009.

Table 2: *Chronology of major activities in 2009*

Activity	Description	Start	End
ASP Injection reduced	Lower injection rates due to budget cuts. Once IETP funding was received, injection rates increased.	January	May
WAC coating inspection.	Coating installed in October 2008 was inspected.	February	February
Increasing well failures	Average run time on wells that scale has been observed is 5 months, down from 38 months. Tubing stuck in the wellbore in 6 wells due to hard scale.	March	December
Poor Water Quality	Oil concentration in injection water averaged 1300ppm.	May	June
FWKO Modification	Modified FWKO internal and external configuration to improve water quality	April	April
New clarifier attempted	100 products bottle tested. 2 worked. Oil concentration in injection water improves to 200 ppm	July	October
Turned on shear pump	Produced polymer concentration was too high. The fluid must be sheared to flow through the WSF and WAC.	April	April
High concentration of Scale inhibitor	The decision was made to put a high concentration of scale inhibitor on problem wells. A database was set up so that scale coupons were installed on every well and pulled every 3-4 weeks. In combination with water analysis, coupon condition and rig workover reports, the concentration and type of scale inhibitor was determined and reviewed regularly.	July	December
Coated downhole equipment	Impreglon coated NTT and slotted, coated tag bars installed on all wells as DHF occurred.	September	December
Water quality getting worse	A new anionic clarifier was gradually implemented in July. Oil concentration in the injection water was 135 ppm in August. The water quality digressed, ending 2009 with approximately 400ppm oil in the water. Produced water parameters at the facility are 9.7 pH, 3.7 cp, 219 ppm polymer.	November	December
ASP Production Response	ASP production response in 17 wells as defined by at least 3 m^3/d oil increase and 5% oil cut.	January	December
ASP injection ended	ASP injection ended December 16. Surfactant tanks cleaned. Polymer only injection is expected to continue until 2012.	December	December

2009 Production

Oil production from the ASP project is lower than forecast due to project start-up delays and operational issues which were discussed in previous reports. Table 3 compares 2009 production to estimated production submitted in the May 2007 IETP application.

Table 3: *2009 Crowsnest ASP Flood Oil Production*

	Base Waterflood	IETP Application Forecast - Unrisked May 2007			Actual		
Month	Oil Rate (m^3/d)	% PV injected	Oil Rate (m^3/d)	Oil Cut (%)	% PV injected	Oil Rate (m^3/d)	Oil Cut (%)
January	44	23.2%	141	5.0%	16.9%	67	2.4%
February	44	24.5%	154	5.5%	18.1%	64	2.6%
March	43	26.0%	165	5.9%	19.3%	56	2.3%
April	43	27.4%	180	6.4%	20.4%	59	2.7%
May	43	28.8%	193	6.9%	21.8%	74	2.8%
June	42	30.2%	204	7.3%	23.0%	85	3.3%
July	42	31.7%	215	7.8%	24.4%	86	3.1%
August	42	33.1%	225	8.2%	25.7%	80	2.7%
September	41	34.5%	233	8.5%	27.0%	83	3.0%
October	41	35.9%	240	8.8%	28.4%	99	3.4%
November	40	37.2%	251	9.2%	29.9%	110	4.2%
December	40	38.6%	262	9.7%	31.2%	113	3.9%

In the May 2007 forecast, 30% PV of ASP fluid injection was anticipated by the end of June 2009. Due to start-up delays and lower than forecast injection rates, ASP injection was completed in December 2009. Production is also below the original forecast based on the percent pore volume of chemical injected (PV). The original simulation predicted that the oil rate response using the green based ASP system would be slower than a conventional system but that the peak rate was higher. Despite the lower production, the simulation continues to show that incremental oil is still expected. Production increases were normalized for Husky's southern Alberta Glauconitic ASP projects (Figure 1) to compare the performance of a green chemistry based surfactant system (Crowsnest) to the conventional surfactant system (Warner). Figure 1 indicates that oil production response was delayed at Crowsnest but is now similar to Warner.

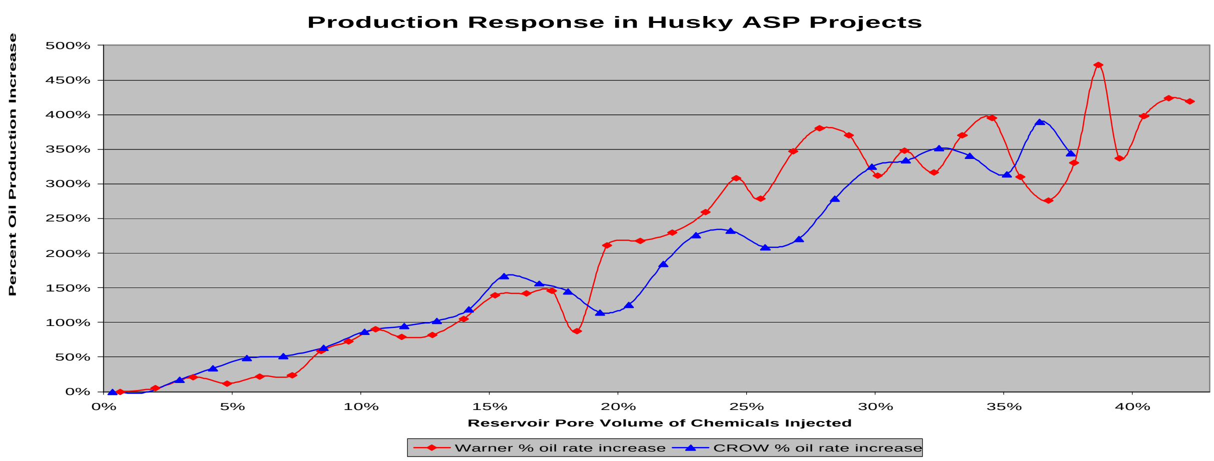

Figure 1: Normalized production increase at Husky ASP projects.

Energy Use
Fluid balances and energy use are provided in Table 4.

Table 4: *2009 Production and Energy Summary for the Taber Glauconitic K pool*

Month	Electricity Consumed ASP Plant (kWh)	Electricity Consumed Wells (kWh)	Produced Oil (m^3)	Produced Water (m^3)	Produced Gas (E^3m^3)	Injection Water (m^3)	Disposal Water (m^3)
January	407,982	11,330	2065	84,983	72	87,316	6454
February	324,457	9,746	1784	67,956	59	70,471	6183
March	351,148	10,918	1730	74,468	63	78,622	6375
April	283,418	11,116	1755	60,498	77	71,468	4036
May	287,122	16,628	2291	76,654	106	84,456	4130
June	277,420	16,435	2544	72,483	96	79,808	3968
July	283,686	16,713	2682	81,986	89	85,318	4344
August	274,857	16,144	2489	86,239	79	86,225	3680
September	527,200	29,340	2502	79,119	81	82,466	2916
October	347,578	16,157	3054	83,697	90	87,877	3658
November	384,831	15,934	3315	72,237	40	92,066	5068
December	466,558	17,373	3497	83,694	57	83,655	5340
Total	4,216,257	187,834	29706	924,014	910	989,746	56151

Reserves
Reserves have been modified based on a simulation update using actual production results to date. Un-risked incremental oil recovery has dropped from 16.6% in the application to 15.0% (Table 5) due to lower than expected production at this time. At the time of the application, it was stated that the green ASP system is expected to have incremental recovery that is 10% higher than that of a conventional ASP system. This remains the expectation as incremental production forecast for the Warner ASP project using a conventional surfactant has been reduced to 12.7%.

Table 5: *Reserve Summary for the Taber Glauconitic K pool*

Production Values as of April 2010	Oil Volume 10^3m^3 (MMBO)	Percent of OOIP (%)
Original Oil in Place (OOIP)	5,100 (32.1)	-
Cumulative Production to date (CTD)	2016 (12.7)	39.5%
Waterflood Ultimate Oil Production	2055 (12.9)	40.3%
ASP Forecast Ultimate Oil Production	2817 (17.7)	55.8%
Incremental Production (CTD)	22 (0.14)	0.4%
Remaining Incremental Production	740 (4.65)	14.6%
Total Incremental Oil Production from ASP	762 (4.79)	15.0%

The incremental production forecast in the original IETP application due to ASP injection has been reduced from 5.3 to 4.8 MMBO.

3. Well information

Well Layout Map

Husky is a 100% working interest owner in the Crowsnest ASP flood. At the end of 2009, the Glauconitic K pool consisted of 49 oil production wells, 20 injection wells, and 9 shut in and observation wells (Figure 2). Producers and injectors may be shut-in for periods of time to balance target pore volumes injected throughout the reservoir and to attempt to maintain target voidage replacement ratios. The 02/9-29-9-16W4 well was pipelined and reactivated May 2009. All wells in the pool are identified in *Appendix A - Well List and Status.*

Well operations

The well workovers in 2009 were dominated by scale issues and attempts to improve conformance by adding perforations (Table 6).

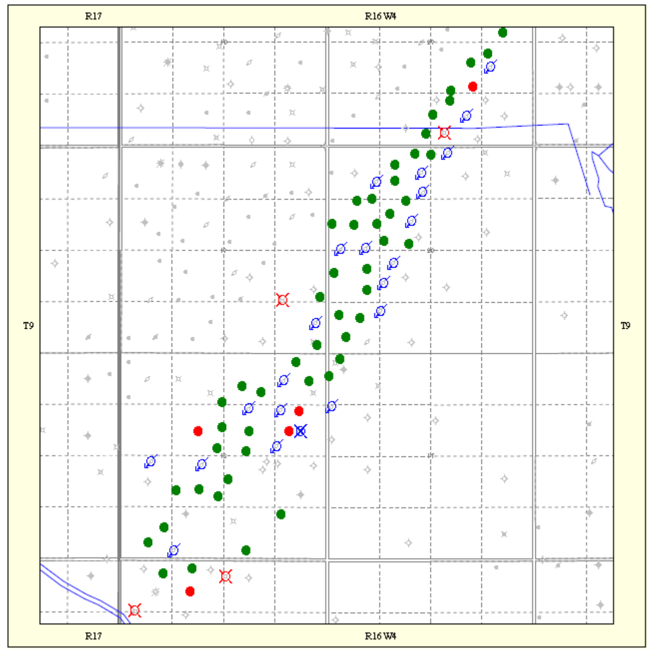

Figure 2: Well status as of December 2009

Table 6: *Glauconitic K 2009 well operation summary (continued on next page)*

Well	Month	Summary from Service rig reports.
102/13-7-9-16W4	January	Slight build-up of scale on last 10 rods. Lots of scale returns with circulation. Last 2 jts of tubing have scale build-up.
102/13-7-9-16W4	October	Lots of scale buildup in rods, rotor has lots of wear. Tubing stuck. Use jetting tool to get clean out tubing. Little scale on tubing or stator after tool ran. Add perfs 982.5-987.5m. Ran in coated slotted tag bar, same tubing as pulled.
100/14-7-9-16W4	December	Light scale on rods, most chrome gone from rotor, bottom of rotor has scale. Scale started on inside of jt 74 and light scale on outside of tubing. Got back scale and small pieces of rubber when circulated clean. Ran coated slotted tag bar and NTT and original tubing.
100/4-18-9-16W4	December	Re-perfed 952.5-958m and performed 20T frac on well.
103/6-18-9-16W4	June	Added perfs 977-979 and performed 20T frac. Ran coated slotted tag bar and coated rotor.
103/6-18-9-16W4	August	Broken rotor 16" from top, no scale observed. Failed in 1.8 months due to coating on rotor that was too tight in the stator.
100/9-18-9-16W4	July	Abandoned 1942 injection well.
102/11-18-9-16W4	July	Added perfs 1002-1006m. Rods in good shape, tubing free of any scale. Ran coated slotted tag bar and NTT.
102/15-18-9-16W4	August	Rotor had wear on lobes, some scale on rods. Added perfs 980-983m, Ran in with coated NTT, slotted tag bar, and coated rotor. Ran in with same tubing and rods as pulled
103/8-19-9-16W4	April	Rotor broken 2' from top, lots of polymer in returns but no scale buildup on rods, tubing, or stator. Added perfs 957-963 & 964-970m. Ran coated rotor and same rods and tubing.

103/8-19-9-16W4	November	Scale on rods and ponies, had to strip out of the hole as lots of scale piled up in tubing. Rotor scaled up. Ran coated NTT, slotted tag bar.
103/4-20-9-16W4	March	No scale on pump.
103/4-20-9-16W4	June	Rods stuck. Added perfs 972-977.5 and 980-982m.
103/4-20-9-16W4	November	Had to hacksaw some rods that were stuck in tubing due to scale and stator rubber stuck in tubing. Some joints full of scale and couldn't remove scale (note this well flowing for almost a month without scale inhibitor). Ran in with stainless steel cap string strapped on side of tubing to get scale inhibitor down to pump. Ran in with new rods.
102/6-20-9-16W4		Flowed back injection well and sent samples to determine solvent. Used jetting tool to perform solvent wash. Injector started flowing back. Couldn't circulate. Drilled out sand and mud. Ran coated packer and tubing.
102/11-20-9-16W4	May	Pin striped out of 94^{th} rod. Trace scale. Added perfs 1032.5-1035m
102/11-20-9-16W4	December	Can't move tubing, couldn't fish - pieces of lined tubing and scale in overshot. Tried casing jack, didn't work. Work tubing by lowering, got out. No scale buildup on rods or outside of tubing, lots of scale on pup joint and stator. RIH with bit and scraper, had to stop several times to circ heavy oil, with some scale in returns. Ran coated slotted tag bar and NTT.
103/11-20-9-16W4	August	Some scale build up on rods. Coated rotor installed
103/11-20-9-16W4	December	Went on well because noticed bad scale on coupon, not because well went down. Tubing stuck. Lots of scale on rods (1/8") and rotor. Rotor missing chrome. Very little scale in returns. Some scale on last 12 joints. Soft scale in returns. RIH cap string to get scale inhibitor to pump. Ran slotted tag bar, NTT, coated pup joint. Ran same tubing string as pulled and new rods.
107/12-20-9-16W4	December	Added perfs 984-986m. Attempted frac. Got 3T into formation.
105/2-29-9-16W4	September	Added perfs 983-987.5m.
104/7-29-9-16W4	January	Scale buildup on rods and in stator. Chrome missing off rotor.
104/7-29-9-16W4	May	Collars belled due to over torque. Rotor missing some chrome on lobes. Scale buildup on rods, some scale buildup on stator and NTT, very little scale on tubing. NTT had one broken slip die. Rubber torn 0.5m from top of pump. Added perfs 985-991m.
102/9-29-9-16W4	May	Swab well, 100% water cut, put well on production.
102/9-29-9-16W4	November	Pumped off due to low inflow. Some wear on rotor. Heavy oil last 20 joints. Tubing drain was blown. Ran bailer, one joint full of frac sand, some cement in junk basket. Ran coated NTT and same rods and tubing as pulled.

Wellbore Schematics
Typical schematics were provided in the 2008 Annual Report

Spacing and patterns
This information was provided in the 2008 Annual Report

4. Production Performance

Production History

ASP injection began on January 23, 2008. The project has cumulatively produced 59 10^3m^3 of oil and 2254 10^3m^3 of water as of April 2010. Daily oil production has increased from 26 m^3/d and 0.9% oil cut to 127m^3/d and 5.3% oil cut. Daily production and injection information is provided in Appendix B and C. The pool was divided into 7 areas (Figure 3) for monitoring purposes. Efforts are made to ensure both production and injection rates are optimized in each area.

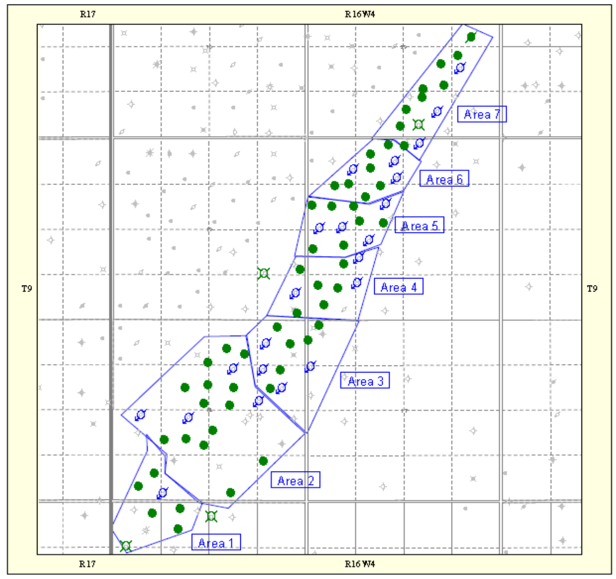

Figure 3: Crowsnest ASP Area map

Actual pool production is compared to the un-risked forecast submitted in the original IETP application in Figure 4. The oil production trend is lower for a number of reasons:

- ASP injection began 4 months later than predicted due to facility delays.
- The forecast assumes 100% run-time and is un-risked. There were frequent well failures and delays getting rigs to wells due to irrigation and weather issues.
- When ASP injection began the oil rate was 26 m^3/d compared to 37m^3/d expected. In January 2008 there were 23 wells that had 100% water cut.
- Injection rates were cut back in early 2009 to preserve capital. Injection rates were restored later in the year when IETP funding was received.

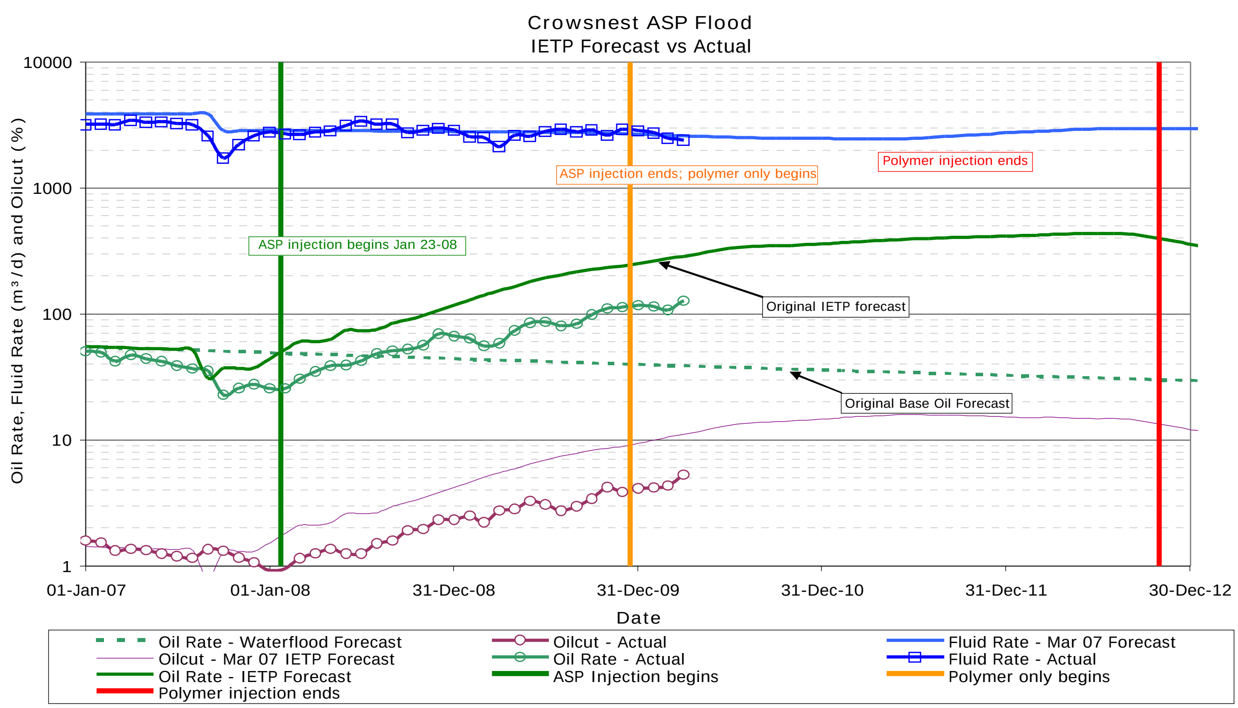

Figure 4: Comparison of production to base waterflood and May 2007 IETP ASP predictions

The best method of evaluating the performance of an ASP flood is to compare production on the basis of reservoir pore volumes of ASP fluid injected. This reduces the impact of facility delays, reduced injection rates, and other operational issues so that the affect of chemical on improved recovery can be independently evaluated. Figure 5 compares actual production to the forecast submitted in the IETP application based on reservoir pore volumes (PV) injected including a forecast assuming a 70% probability of success. Although lower than the simulation, oil production has generally been within the range expected when the project was designed. In March and April 2010, production was outside the range due to lower total fluid production caused by downhole failures in key wells during road bans. Service rigs were delayed in repairing these wells. The oil cut continued to increase demonstrating the EOR process is working. At the end of April 2010, approximately 31% PV of ASP solution has been injected (30% PV target) and approximately 5% of polymer only solution. Final ASP injection was completed in December 2009 and will be followed by a total of 40% PV of polymer solution.

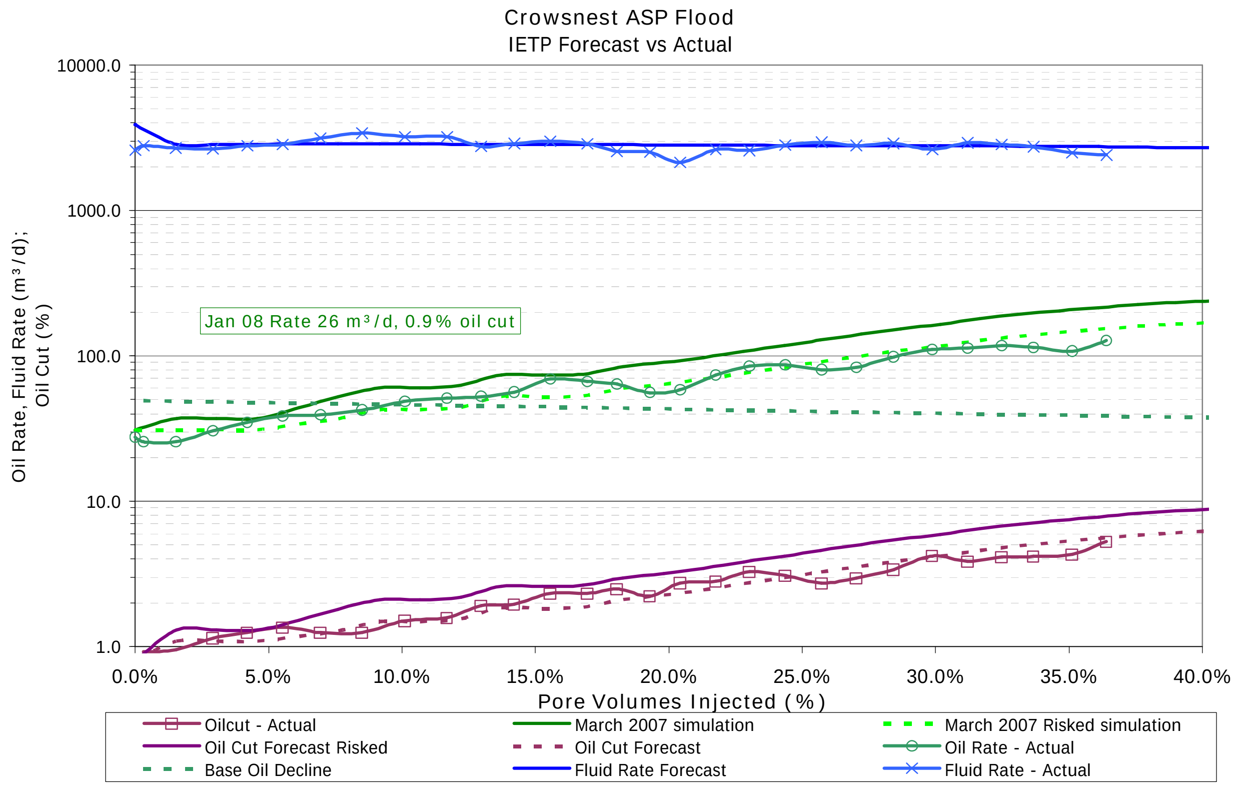

Figure 5: Comparison of production to base waterflood and IETP ASP predictions based on pore volumes injected

Injection Performance and Data

The target injection rate for the Glauc K pool is 2900 m^3/d but the average injection rate since the project began is approximately 2800 m^3/d (Figure 6). This is due to facility downtime, non-technical reasons such as a revised 2009 budget due to lower oil prices, and limits of injectors in the south part of the pool. As a higher viscosity fluid is injected further into the reservoir, the average injection pressure has steadily increased from 4 MPa when the project began to the current average injection pressure of 11.6 MPa in March 2010.

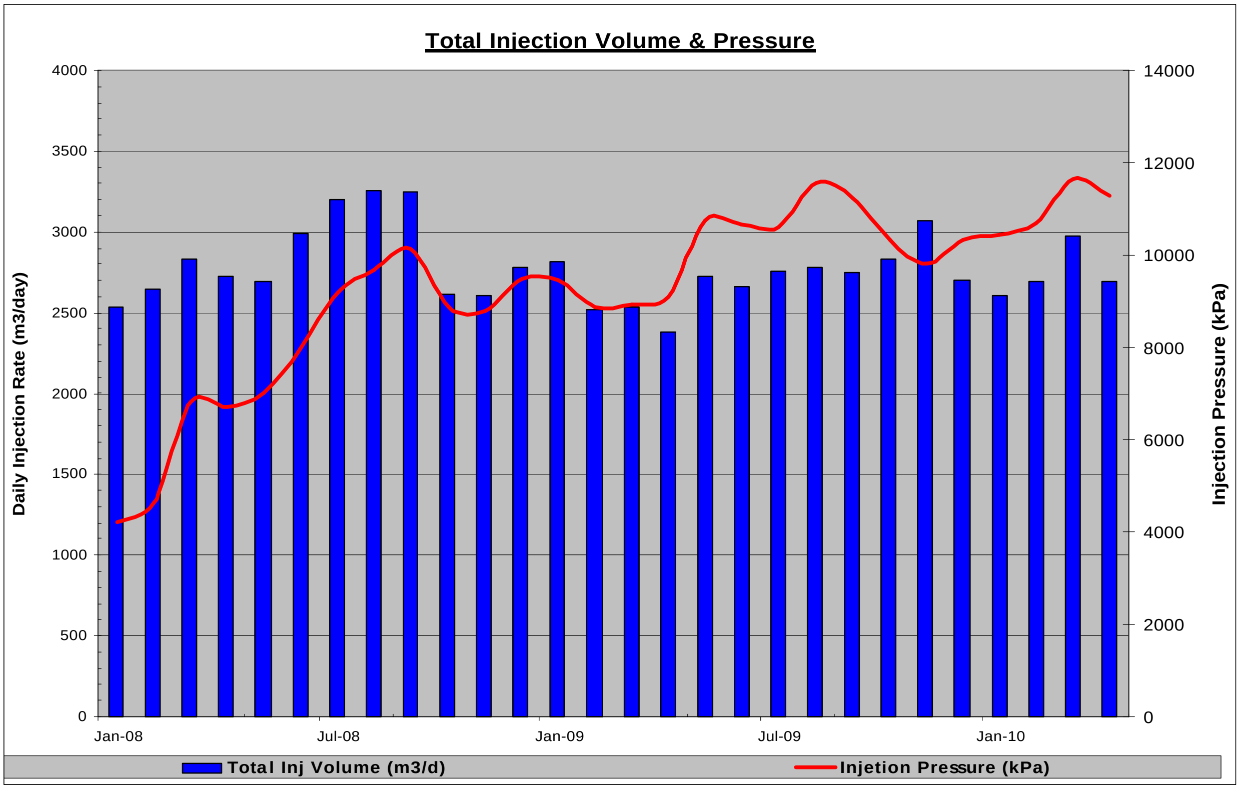

Figure 6: Taber Glauc K pool injection rates and average wellhead pressure

Voidage Replacement Ratio

Cumulative VRR by area ranges between 0.87 and 1.14 with a cumulative VRR for the pool equal to 0.99 (Figure 7).

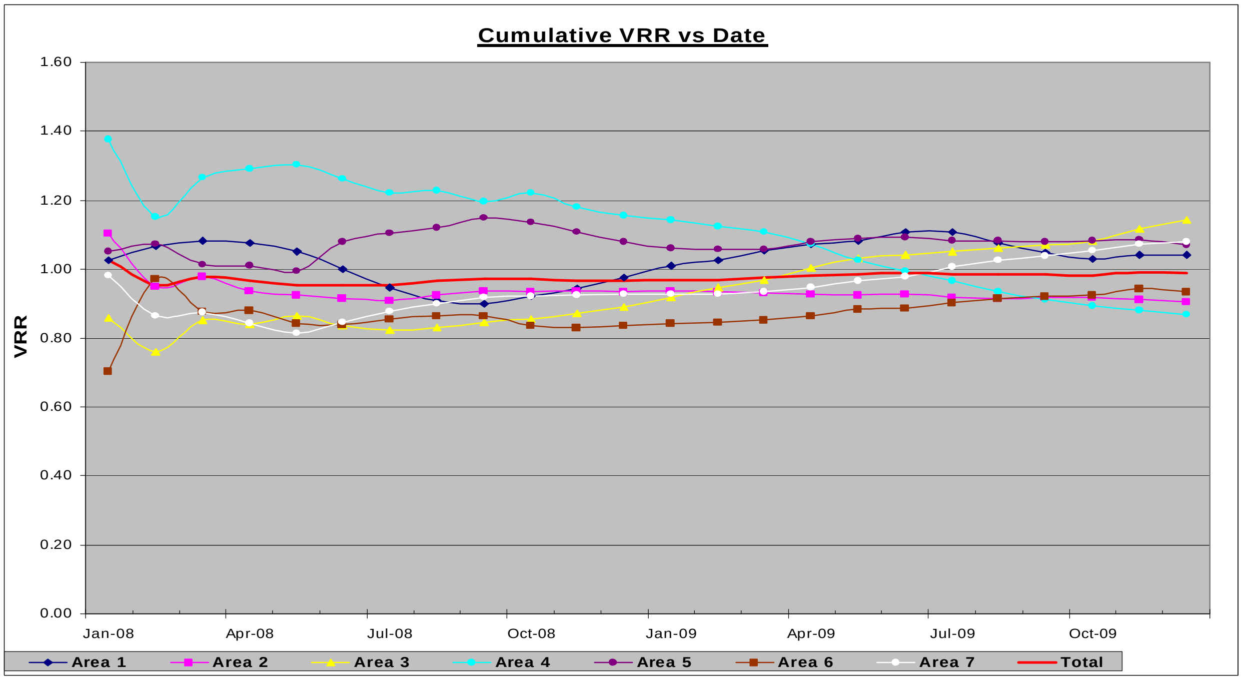

Figure 7: Crowsnest Voidage Replacement Ratio by Area

Composition of Production Fluid

A standard water analysis from each producer is reviewed each month to monitor changes in produced fluid properties. This information is essential to understanding the movement of fluid through the reservoir and the effectiveness of the ASP flood. Produced water analyses are provided in Appendix D.

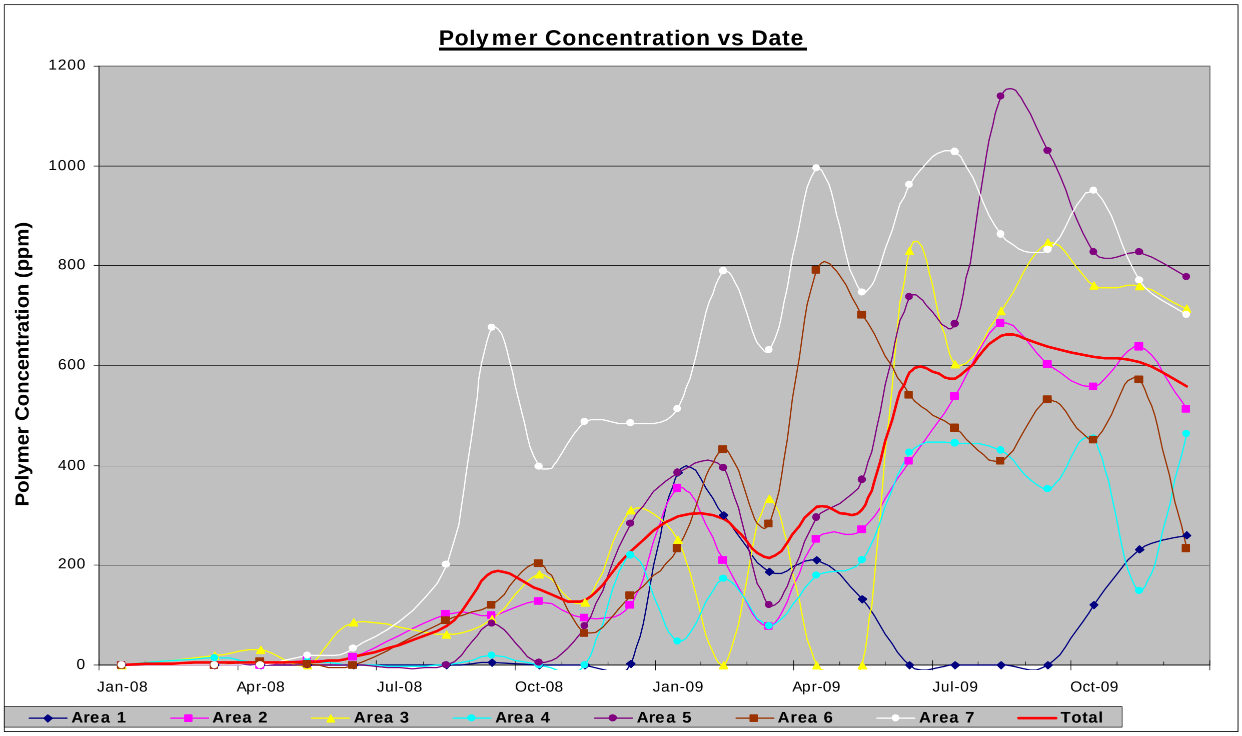

Figure 8: Average produced polymer concentration by pool and by area

A number of parameters are tracked when monitoring ASP floods. The weighted average polymer concentration is calculated for the pool and for each area shown in Figure 8. Since it is a weighted average, it depends on if the well is producing or not and can be volatile on a month to month basis for individual regions. On a pool basis, the average produced polymer concentration is 557 ppm. For comparison, after 31% PV had been injected in the Warner ASP project, the pool weighted average produced polymer concentration was 452 ppm. The polymer injection concentration at Crowsnest increased from 1100ppm during alkali-surfactant injection to 1500ppm during polymer only injection.

Production well 104/14-20-9-16W4 shown in Figure 9 is one of the wells that first responded to ASP injection. Future oil production and oil cut response can often be predicted by key produced fluid parameters. 104/14-20 was producing approximately 1 m^3/d at 1% oil cut. The first indication that an ASP flood is starting to work occurs when the water hardness starts to increase. The Glauc K pool water hardness (a mathematical combination of Ca^{2+} and Mg^{2+}) often increases as previously by-passes areas of the pool are produced since the formation water is harder than the makeup water. The second indication of ASP response is the detection of polymer in produced water. This is quickly followed by increases in pH, TDS, Na, a change in the carbonate to bicarbonate ratio and a decrease in the water hardness as softened injection water is diluted through the reservoir. In earliest wells, polymer was observed within 2 months.

Finally, the front of the oil bank that has been established begins to be produced resulting in an increased oil cut for 104/14-20 peaking at 22%. Peak oil production of 9.6 m^3/d was achieved in Dec 2009. Generally, the longer it takes for oil production increases, the greater the increase in oil production when the oil bank reaches the well. As this was one of the first wells to respond, it was one of the first wells to start decreasing in production.

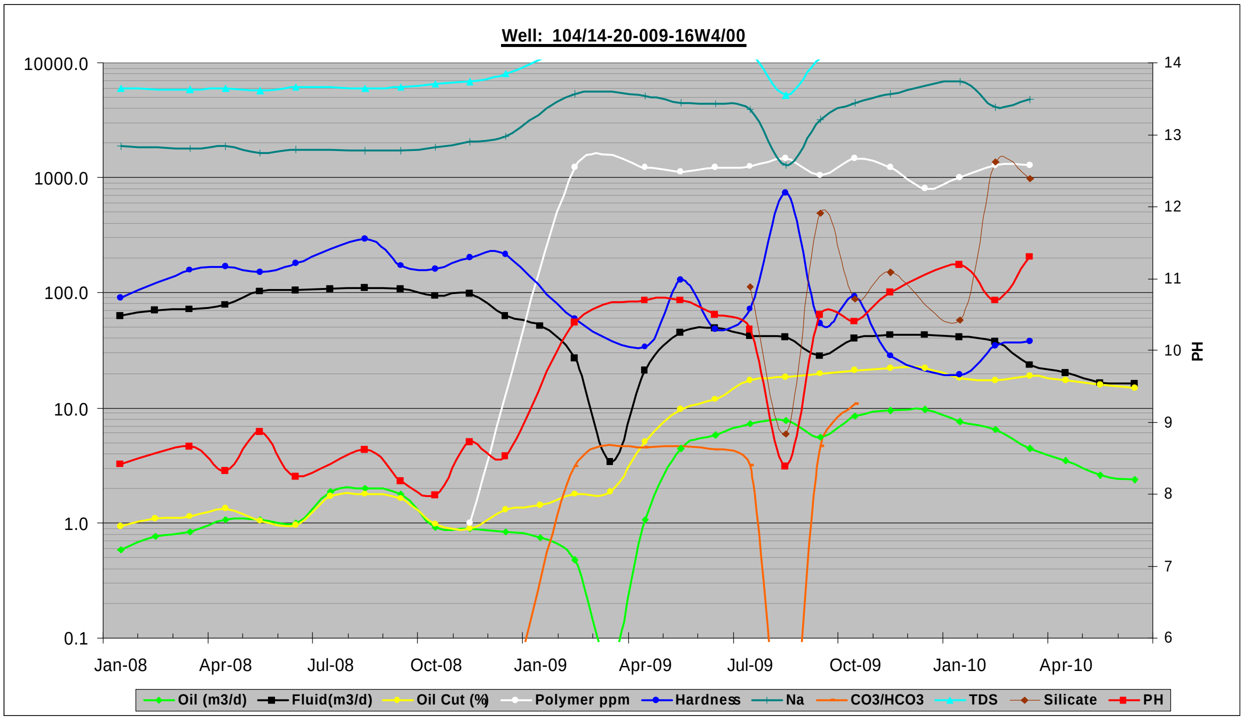

Figure 9: Produced water analysis of 104/14-20-9-16W4

Other sample wells that have responded are shown in Figures 10 to 14

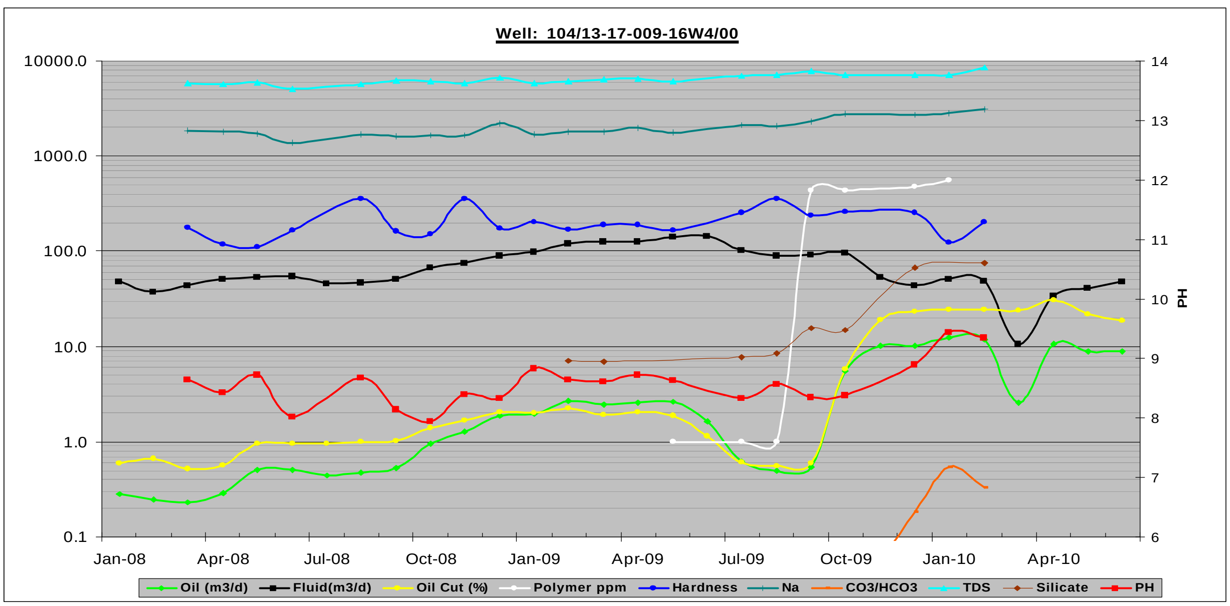

Figure 10: Produced water analysis of 104/13-17-9-16W4

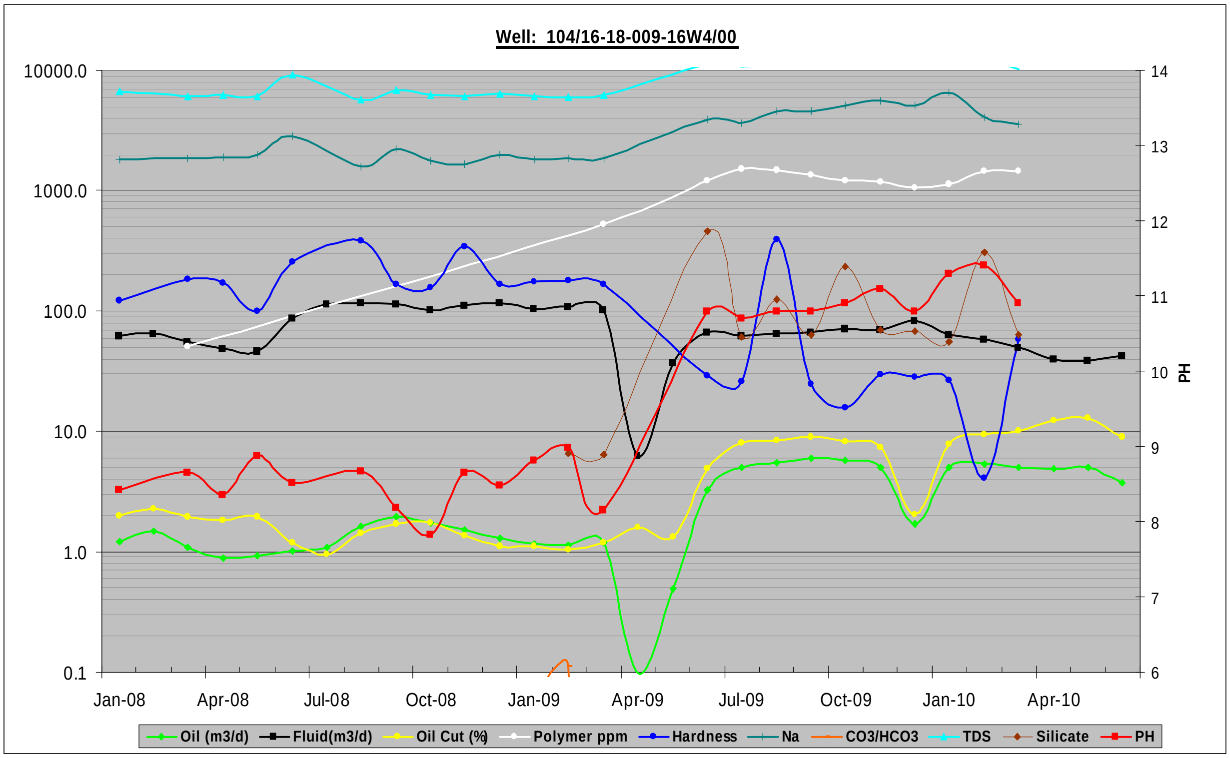

Figure 11: Produced water analysis of 104/16-18-9-16W4

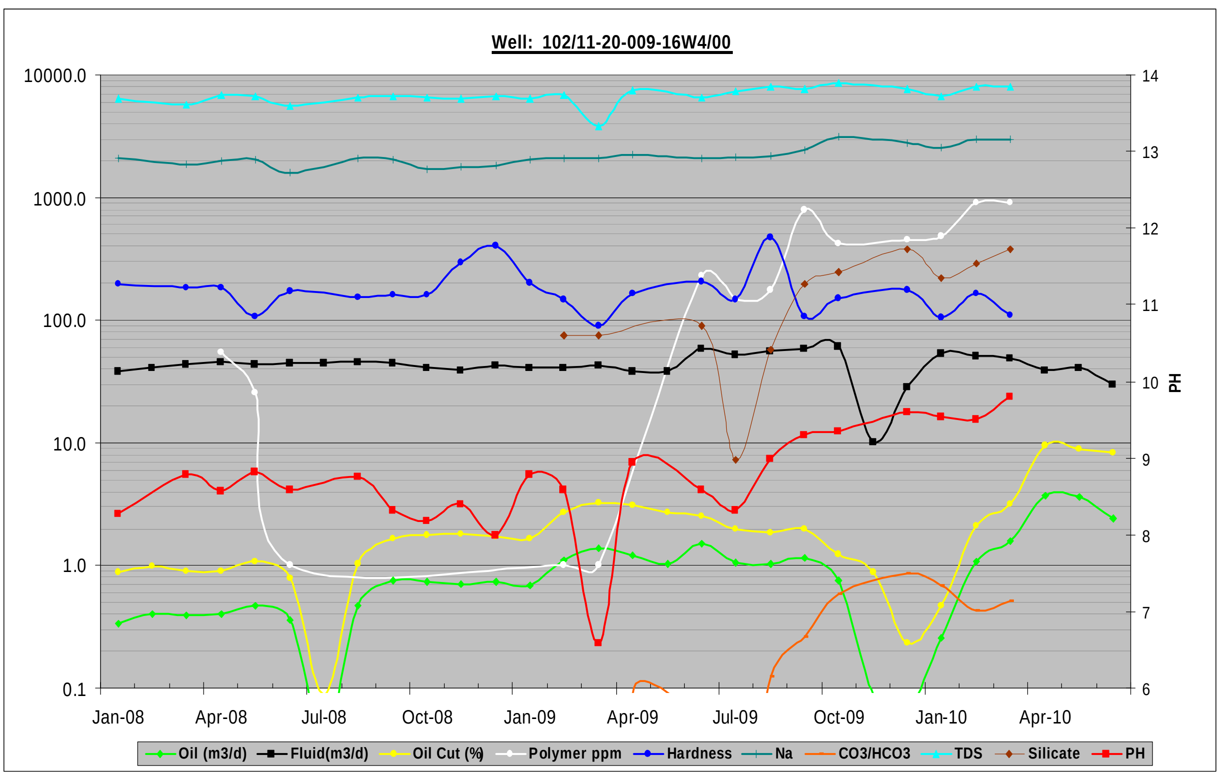

Figure 12: Produced water analysis of 102/11-20-9-16W4

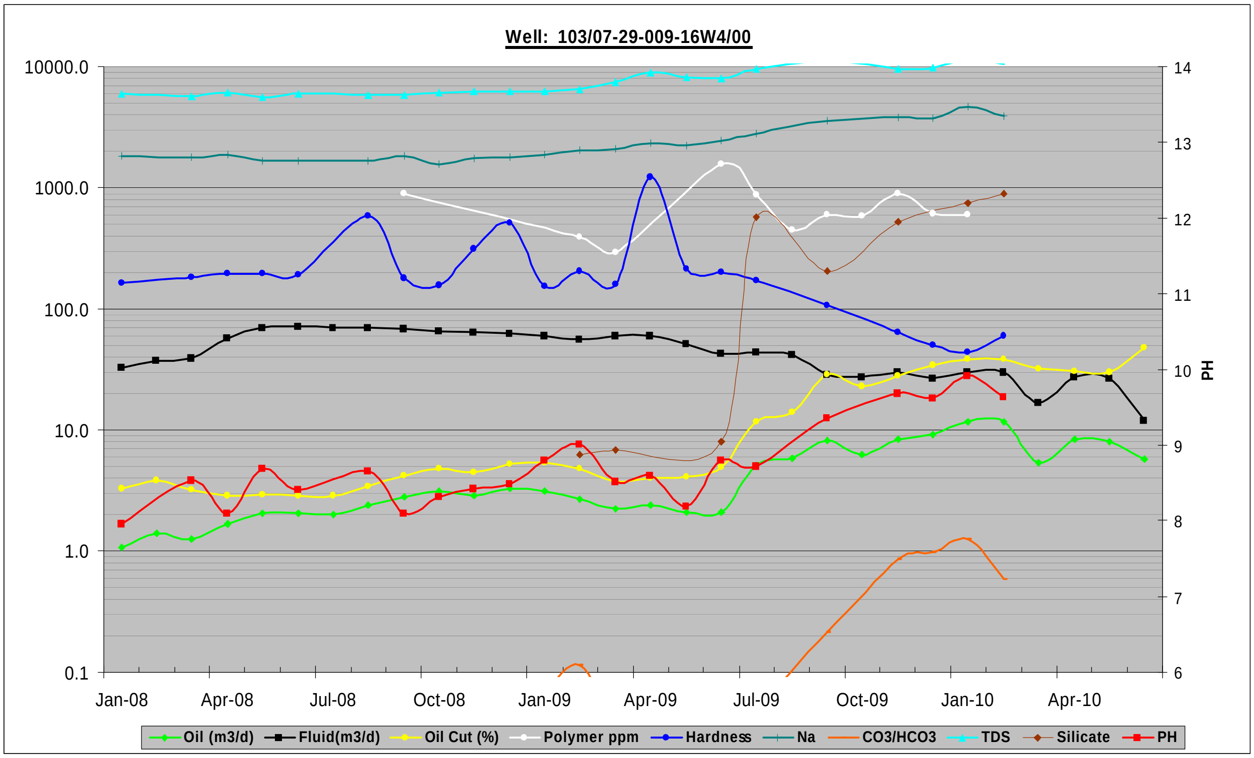

Figure 13: Produced water analysis of 103/07-29-9-16W4

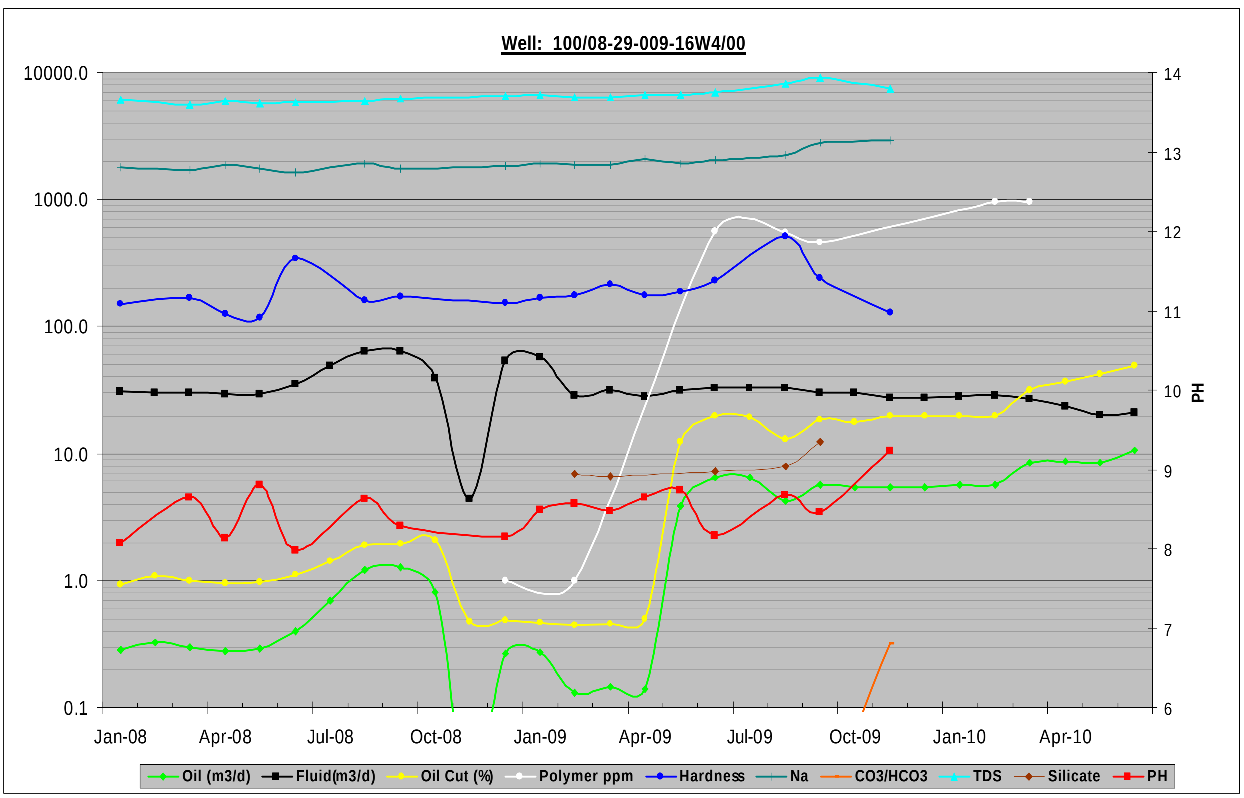

Figure 14: Produced water analysis of 100/08-29-9-16W4

Composition of the Injection fluid

Injection is monitored daily to ensure the correct concentration of ASP is injected in the reservoir. The fluid viscosity is measured at the plant and at an injection well at the north and south ends of the pipeline system. ASP injection fluid properties was also measured to ensure the solution is within a viscosity range between 20-26 cp, a screen factor of 52-68, and conductivity between 32.5-39.5 mS/cm. There was very little difference between the values at the plant and at the injection wells. On December 16, 2009, ASP injection ended and polymer only began. The injection concentration was increased from 1100ppm to 1500ppm because lignosulfonate wasn't being injected in the ASP solution. Lignin is a natural polymer. The new target parameters are a viscosity between 38-45 cp and a screen factor ranging from 78 to 85.

Pressure

Static gradients taken in 2009 are provided in Table 7. See previous reports for historical pressure information.

Table 7: *2009 Static Gradients in the Taber Glauconitic K Reservoir*

Well	Last recorded pressure at MPP
103/13-07-9-16W4	9165 kPa
102/15-17-9-16W4	9604 kPa
102/08-19-9-16W4	9768 kPa
102/2-29-9-16W4	13604 kPa
102/9-29-9-16W4	3192 kPa

5. Pilot Data

Geology and Geophysical Data/Laboratory Studies

Geology, geophysical data, and laboratory study results were provided in previous reports.

Reservoir Data

Characteristics making the Glauc K pool an ASP candidate are excellent waterflood response, 34°C reservoir temperature, oil viscosity of 85 cp, and reservoir quality presented in Table 8.

Table 8: Basic Reservoir Properties for the Taber Glauconitic K pool

Formation:	Glauconite	Initial Pressure:	10 162 kPa
Lithology:	Sandstone	Current Pressure:	9 600 kPa
Mean Formation Depth:	960 m KB TVD	Bubble Point:	4 306 kPa
Permeability:	1517 mD	API Gravity:	18.5 °
Porosity:	23%	Rsi:	12.4 m^3/m^3
Swi:	16%	FVF:	1.05 R m^3/Sm^3
Average Net Pay:	6.5m	Reservoir Drive – Primary:	Fluid Expansion

Interpretation of Pilot Data

The project is slowly materializing with oil production increases up to 13 m^3/d observed in some wells. Conversely, operational issues related to water quality and scale has been very challenging although significant progress is being made in these areas. The coating applied to the water softeners October 2008 was successful and will be used in future projects.

A positive sign is that oil production in each area, outside of Area 1, has followed a similar trend and areas with greater pore volume of chemical injected generally have higher oil rates (Figure 15). This demonstrates that the chemical is working similarly throughout the field. Area 1 only has one injection well and was known to have the most complex geology.

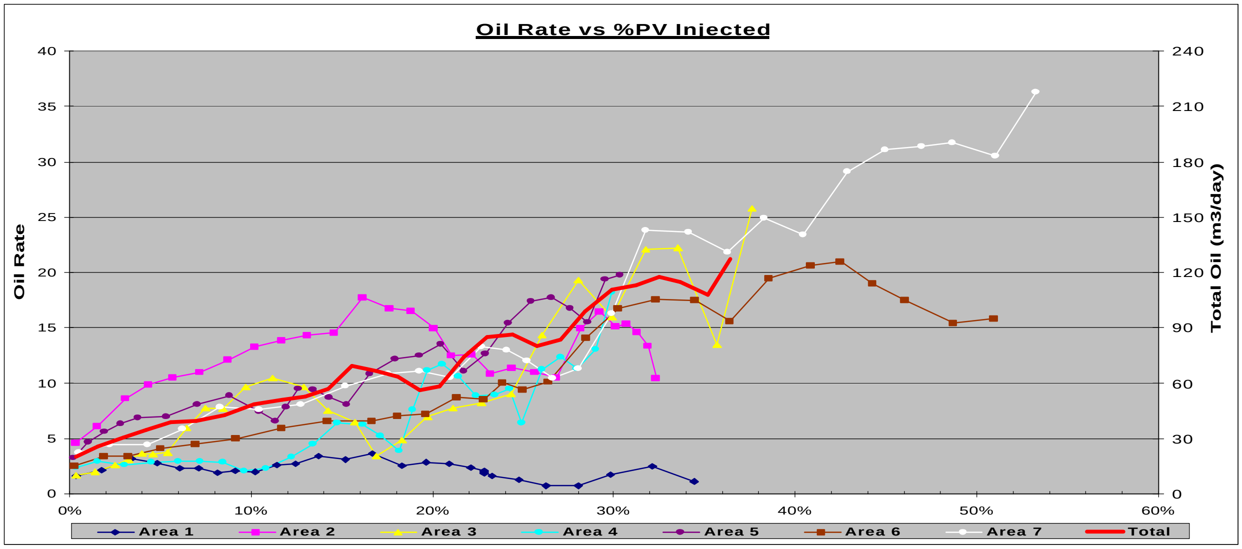

Figure 15: Area response based on pore volumes of chemical injected.

The oil cut has improved in each area, except Area 1, with significant improvements in Area 3 which increased from 0.4% oil cut to 9.8% oil cut and Area 7 which increased from 1.1% oil cut to 9.4% oil cut (Figure 16).

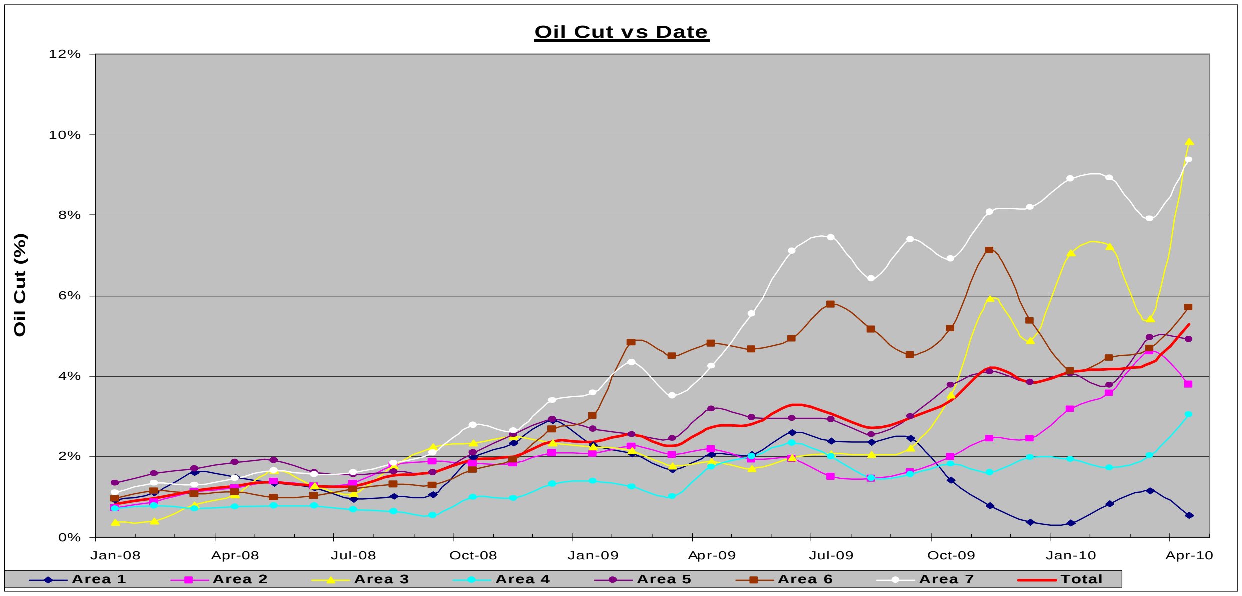

Figure 16: Oil cut in each area of the pool.

Incremental Production

Cumulative incremental oil from ASP flooding was 22.8 10^3m^3 in April 2010. Incremental production is low because ASP production was lower than the base waterflood decline for a longer period of time than forecast due to facility construction and oil production response delays. The reservoir simulation indicated the highest ultimate recovery would be achieved by targeting 2900 m^3/d injection during chemical injection. In total, 27 additional wells were put on production and existing wells were slowed down to reduce total fluid production from 4000 m^3/d under the waterflood. At the start of the project 23 out of 52 wells were making 100% water cut and the pool oil cut was 0.9%. Now only 3 wells have a 100% water cut. In April, oil production was 88.5 m^3/d (557 bopd) above the base water flood decline (Figure 17). The effectiveness of the green co-surfactant ASP system can not be determined at this time because less than 3% of the expected incremental production of 762 10^3m^3 has been recovered.

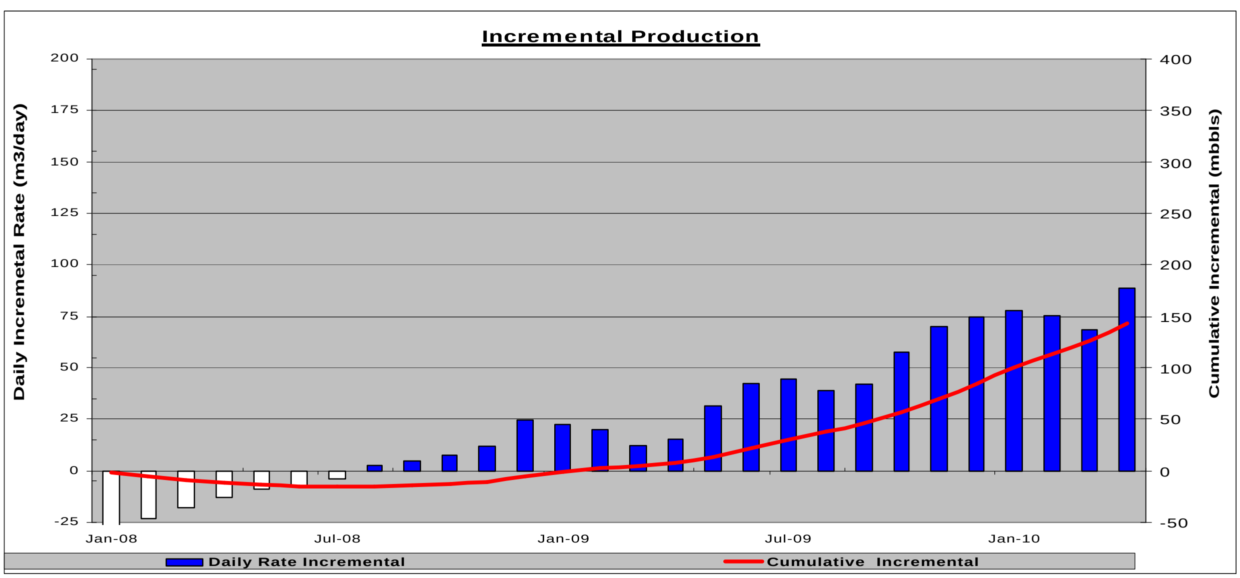

Figure 17: Incremental oil production.

6. Pilot Economics to date

Tables for expected revenue, capital, operating costs, and royalties are included in Appendix E in the same format as what was submitted in the May 29, 2007 IETP application. Economics of the project are similar to those provided last year as lower production and higher royalties were offset by oil prices which are $10/bbl higher through 2012 and $5-7/bbl higher thereafter. The NPV of the crown royalty rose sharply due to higher prices in 2010 and the adjustment to the royalty calculation Husky made to tie closer to actuals through April 2010. In addition, the t-factor changed from 0.9 to 0.78. Operating costs are higher in recent years but lower overall due to an earlier economic limit.

Capital

Table 9 lists estimates submitted in 2007, capital at the end of Q1 2010, and expected final costs.

Table 9: *Comparison of actual costs to original estimates*

Description	IETP Estimate May 2007		Desription	LTD Actual Q1 2010	Estimated Total
Total Facility Costs*	**$ 27,000,000**		**Total Facility Costs***	**$ 31,871,166**	**$ 31,871,166**
			New construction	$ 5,226,703	$ 5,226,703
			Liners in existing lines	$ 857,769	$ 857,769
			Injector coating, measurement and control	$ 629,737	$ 629,737
Total Pipelines	**$ 5,320,000**		**Pipelines**	**$ 6,714,209**	**$ 6,714,209**
			Drilling	$ 2,549,495	$ 2,549,495
			Conversions	$ 3,419,978	$ 3,419,978
			Optimizations	$ 3,882,737	$ 5,145,000
			Reactivations	$ 3,124,642	$ 3,124,642
Total Reservoir Costs	**$ 9,000,000**		**Total Reservoir Costs**	**$ 12,976,852**	**$ 14,239,115**
			ASP System Design	$ 177,148	$ 177,148
			Monitoring	$ 204,757	$ 350,000
Total Laboratory	**$ 250,000**		**Design and Testing**	**$ 381,905**	**$ 527,148**
Total Chemicals	**$ 28,969,000**		**Total Chemicals**	**$ 27,693,002**	**$ 36,563,000**
			Scale/Water Quality Issues	**$ 2,129,897**	**$ 5,500,000**
Total Project	**$ 70,539,000**		**Total Project**	**$ 81,767,031**	**$ 95,414,638**

* Does not include salvage value

The project is over the original estimates mostly due to cost escalation during periods of high demand in 2007 and 2008 related to equipment, raw materials, and chemicals. These issues and the facility scope changes were discussed in previous reports. In addition, costs have been added to deal with changing produced water and field development optimization.

Chemical Injectants

There was little variability in chemical prices in 2009. A fixed price for the caustic was negotiated in 2008. The surfactant price was stable throughout the entire project because they are not derived from petroleum products. Polymer was at the floor price until October 2009 when surcharges related to freight and raw material prices were activated.

7. Facilities

The facilities were discussed in the 2008 annual report. There were no major capital costs in 2009. Most of the costs were related to well optimizations and scale/water quality issues.

Operational Issues – Facilities
In 2008, the largest operational issue involved the water softeners. Water softeners have been rubber lined for decades. In October 2008, water softeners were coated by DSI Dalco Service Inc. based in Red Deer, Alberta. The coating was checked in February 2009 and again in February 2010 and was determined to be in excellent condition. This is one success from the project and the coating will be applied to vessels in future ASP projects.

At the end of 2008, scale was observed in 4 producing wells. Scale issues continued to be a problem in 2009. Of the 50 wells producing at the end of 2009, scale was observed on the rods, tubing, and pump on 18 wells. In 14 of these wells, the run-time was significantly reduced as shown in Table 10. The scale inhibitor concentrations were increased from 50-75 ppm up to 500ppm as required beginning in July 2009. This appears to have helped the run time on these wells. The first well to have an increased scale inhibitor concentration was 104/7-29. The well workover frequency went from 2.8 and 3.8 months to 12 months using higher scale inhibitor rates. Scale coupons are installed on every well and are monitored every three to fours weeks. Depending on the amount and colour of the scale observed on the coupon, the type and concentration of scale inhibitor may be changed. Currently there are 4 different types of scale inhibitors being used with more products to be attempted in 2010. Calcite inhibitors, silicia inhibitors, and a combination of both types of inhibitors are currently being used. The other major contribution to increased run time was the use of a cap string to get the correct scale inhibitor concentration to the pump. The 103/4-20 had run times of 2.8 and 3.6 months prior to use of the cap string but currently has a run time of 6.3 months since it was attached to the outside of the tubing.

Table 10: *Increased DHF frequency in wells with scale present*

Taber Glauc K wells with scale present.	Number of wells	Well Run Time prior to ASP (months)	Well Run Time after scale observed (months)	Current Well Run Time as of April 30 (months)
Problem wells*	14	43.7	4.7	6.1
Non-problem wells	4	24	15	11.2
All wells	18	37.7	6.7	7.5

*problem wells are defined as having less than 6 months run-time.

Injection water quality has been a challenge for this project. The oil concentration in the injected water increased from approximately 35 ppm oil in the water to an average of 1300 ppm in May 2009 which is almost double the average concentration of 650 ppm in Q4 2008. In the reservoir, one of the mechanisms used to produce more oil is the use of surfactant to emulsify oil into water. At surface facilities, there have been issues related to reversing this process and treating the produced water. Clarifiers that worked in March 2008 did not work as well in November 2008 and were underperforming in May 2009. These unexpectedly poor injection water qualities may be the result of using green chemistry based surfactants because the oil concentration in the injection water in the Warner ASP flood peaked at 400 ppm after ASP injection was complete. The chemical company that treats facility water bottle tested approximately 100 commercial and non-commercial products that could work with the emulsified oil created as a result of the unique co-surfactant system used in this project. Of the 100 tested, 6 appeared to work. The 6 that worked were tested further and 4 caused emulsions and were eliminated as candidates. During the month July 2009, one clarifier product was gradually added to the facility, test satellites, and specific problem wells with significant improved injection water quality shown in Table 11. Water quality continued to get worse throughout the year as more ASP chemicals were produced but it was better than before the new clarifier was added. Fifty new products were bottle tested at the end of 2009 and there appears to be one product that may be field test in the third quarter.

Table 11: *Injection water quality before and after new clarifier product*

Month	Facility Total fluid (m^3/d)	pH	cp	pH	IGF in (oil ppm)	IGF out (oil ppm)	WSF in (oil ppm)	ASP water (oil ppm)	Non-ASP water (oil ppm)
May 2009	4900	8.7	2.4	8.7	2400	2100	1200	1125	2150
Aug 2009	5200	9.3	2.7	9.3	1850	550	325	135	400
Dec 2009	4950	9.5	3.5	9.5	1700	900	540	425	800

Due to the poor water and increased produced water viscosity containing ASP chemicals, the throughput of the walnut shell filters and softeners was reduced. The poor water quality resulted in increased backwashes and manual cleaning of the WSF screens every 2 to 4 weeks. The polymer was sheared by boosting the fluid pressure and then pumping through a choke beginning April 2009. This reduced the viscosity to 1 cp and allowed the fluid to flow through the media in these two vessels.

As stated in the 2008 annual report, chrome coating was stripped off some rotors when pulled out of the hole. Nickel-based coatings on the rotors appear to hold up a better but the main downhole improvement was coated, slotted tag bars and coated NTT. This new coated equipment was first applied in May 2009. It helped maintain flow by reducing the amount of scale that deposited on the equipment and delayed the pump intake from getting plugged. Now in every well workover, coated downhole equipment is used as standard procedure.

Scale is also building up in the pipelines so increased pigging frequency, even in coated and lined pipelines is now part of regular maintenance procedures.

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8. Environmental/Regulatory/Compliance

Environment and Safety
In 2008 Husky implemented the Husky Operational Integrity Management System (HOIMS) to improve Husky's health, safety, asset integrity and environmental performance. HOIMS integrates both occupational and process safety into one comprehensive management system. HOIMS in comprised of 14 fundamental elements, including Safe Operations, Risk Assessment and Management, Personnel Training, Environmental Stewardship, Compliance Assurance and Information Documentation. All levels of management at Husky are committed to the principles of HOIMS and are dedicated to having a safe working environment at Husky. The integration of HOIMS was continued in 2009 with improved processes related to operational procedures and documentation.

There are four main environmental advantages to the new ASP system proposed by Husky:

1. Using surfactants derived from renewable raw materials to produce incremental oil

2. Lignin is a waste product of the pulping process that is used to produce sodium lignosulfonates, a by-product of the pulp and paper industry.

3. An ASP system that would be less damaging to the environment. Conventional surfactants are considered to have a mild toxicity but lignosulfonates are non toxic. The most common use of lignosulfonates is as a dust suppressant for roads and it is already been established in Alberta for use on gravel roads. If there was a spill, the product is completely biodegradable.

   APGs are an agricultural-crop-based combination of fatty alcohols (coconut and palm oils) and glucose (corn, wheat, potato) and are mostly used in personal care formulations, cleaners, and agricultural formulations. APGs are made from renewable and natural raw materials and are readily biodegradable. In fact, the APG chosen for this project has been approved for use in eco-labeled "Good Environmental Choice" by Swedish Society for Nature Conservation[1] which is the largest environmental organization in Sweden. The ecotoxicity[2] profiles of APGs are very low[3] and they release no undesirable by-products such as nitrogen, ethylene oxide and preservatives[4] upon decomposition.

4. Reducing the use of petroleum based products in the ASP system. There is a complete reduction in the use of petroleum sulfonates and polymer (propylene based) use is reduced.

Regulatory
The injection wells were approved under Directive 51 with a Maximum Wellhead Injection Pressure of 15 300 kPag. No injection wells have exceeded this pressure. Average injection pressure is currently 11 600 kPag.

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[1] Cognis Presentation to Husky March 2007 *"APG's for EOR"*
[2] The study of how chemicals affect the environment and the organisms living in it.
[3] United States Environmental Protection Agency, *"The Presidential Green Chemistry Challenge Awards Program, Summary of 1996 Award Entries and Recipients"* http://www.p2pays.org/ref/13/12041.htm (May 28, 2007)
[4] Cognis website. *Add APG® surfactants – Power to your formulations,* http://cognis.com (May 28, 2007)

The project received Directive 65 Approval (Approval 10860) to inject ASP into the Taber Glauconitic K pool in August 2007. A modification was made to the original approval in September 2009 because a condition of the original approval was that the polymer only concentration needed to be between 0.055 and 0.11 weight percent. Approval 10860B was granted to change the approved polymer only concentration to between 0.075 and 0.18 weight percent.

Other conditions of the approval are:

- The ASP solution will not less than 0.5wt% NaOH, 0.10wt% surfactant, and 0.11wt% polyacrylamide polymer
- The polymer solution will be polyacrylamide polymer between 0.075 and 0.18 wt%.
- ASP injection will be not less than 30% PV followed by not less than 30%PV polymer solution
- Must maintain a VRR = 1.0 on a project basis
- Shall target a VRR = 1.0 on a monthly basis
- Monthly sampling of produced water to determine ASP breakthrough
- Presentation to the EUB required annually with the first to occur before June 30, 2007.

Husky is satisfying the requirements of Directive 65.

Shut down and Environmental Clean Up

The facility will be in operation until at least 2012. Reclamation of the ASP Plant and injection site will meet all Alberta Environment requirements. At the time of abandonment a Phase I Environmental Assessment will be completed. If any issues are identified following this, a Phase II Environmental Assessment will be completed. Remediation will be conducted if necessary. The site will be reclaimed and a Reclamation Certificate will be applied for.

Once wells and facilities have reached the end of their operational life, Husky has a corporate asset retirement obligation to reclaim the sites to a productive state. This consists of plugging and abandoning wells, removing and disposing of surface and subsurface equipment and facilities, and restoring the land to the state required by ERCB regulation. Although this will be 25+ years into the future for the Glauc K pool, Husky has considerable expertise in this area and is committed to meet all provincial and federal environmental regulations now and in the future.

9. Future Operating Plan

Project Schedule

Full ASP injection began January 23, 2008 and continued until December 2009. 40% PV polymer only injection is expected to continue following ASP injection until December 2012. Efforts are being made to determine if the incremental oil recovery performance using surfactants derived from renewable natural resources is higher than from ASP floods using conventional surfactants but more time is needed.

Changes in pilot

Injection and production rates are continually being monitored and adjusted to meet targets. Targets will be review regularly as additional production results and produced water analyses are obtained so that ASP chemical is placed efficiently and cost effectively throughout the reservoir.

Husky will also review extending the length of time the chase polymer solution to 60% PV injected. This decision will be made in 2012 depending on updated simulation results, the oil price, and the price of polymer at that time. In light of this time frame, the salvage value of the facility has not been determined.

Optimization strategies

Currently the largest areas for operating cost optimization are in the areas of water quality and scale. Husky is continuing to work with chemical companies to identify new clarifiers and scale inhibitors. If an effective clarifier can be found, treating costs could be reduced through lower chemical use.

Significant progress is being made on new scale inhibitors. The objective is to find a product that works on both calcite and silicate scales at low concentrations. If a product was found, cost savings could be realized with lower scale inhibitor costs, reduced well servicing costs, and increased pump efficiencies.

Regions 2 and 4 have injected less ASP chemicals than other areas of the pool on a reservoir pore volume basis. An injection well application was submitted for 103/6-18-9-16W4 in March 2010. These areas are being reviewed for additional injection optimization programs. Infill drilling locations are also being considered to access by-passed pay where oil banks are believed to have been established and for possible injection locations. In addition, older production wells with 4 inch casing are being reviewed as re-drill candidates using 7 inch casing. This will allow for higher flow of high viscosity produced fluid and will result in fewer issues with service rigs attempting to work in small wellbores that have hard, cement-like scale present.

10. Interpretations and Conclusions

This has been a very challenging project due to many operational, contractual, and technical issues. There are some valuable lessons learned but it is still early in the project to understand all the implications of the decision to use green chemistry based surfactants. More time is required to resolve some of these issues and to evaluate if this innovative co-surfactant system results in a more effective ASP system at a lower cost. Despite these challenges, Husky made progress in 2009 on addressing many of the complex issues related to implementing a successful ASP flood.

Some of the key lessons from the project are:

- A clarifier was found that worked for a period of time at lower concentrations. A new product was found at the end of 2009 that appears to work better in bottle testing. This product is still being studied.
- Progress was made on dealing with scale. The solution to increasing well runtimes and increased facility throughput will be a combination of mechanical solutions, the correct chemical products and volumes, and operational procedures. Changes in operating practices including pigging, frequent filter changes, well coupons and produce water parameter monitoring.
- Scale is evident on wells when the produced water is above 9 pH and below 11 pH. Outside of these conditions, scale does not form. In 2010, since alkali injection ended in December 2009, it will be important to increase scale inhibitor on high pH wells as the produced water pH drops below 11. Conversely, on lower pH wells, it is important to increase the scale inhibitor as the produced fluid pH increases. In a previous project, this was 4-5 years after the chemical injection began.

Technical and economic viability can not be determined at this time. Results are still promising but incremental recovery at this time is less than 3% of the final total incremental recovery. Production is lower and royalties are higher but due to higher prices the un-risked after tax rate of return remains approximately 18%.

Lessons learned from this project on the facility design were incorporated into the design of an ASP project in Saskatchewan that began at the end of 2009. Over $5MM in savings are estimated to have been made on that facility that has the same design capacity.

At Crowsnest, ASP production is now 88.5 m^3/d (557 bopd) above the base decline and 101 m^3/d (636 bopd) above the oil rate when the project was started. It is too early to determine, but expected incremental oil recovery is expected to be 4.8 MMBO, or 15.0% OOIP which is a higher recovery factor than what is expected at the Warner ASP project using a conventional surfactant. There are uncertainties about the affect of unconventional surfactants used in this project on increased scaling rates, poorer water quality and the ultimate incremental oil recovery. Husky is not using green based surfactant in other projects until these uncertainties are resolved and it can proved that surfactants derived from renewable raw materials are as equally effective, or as expected, more effective than conventional surfactants. Husky is more encouraged about the use of a green chemistry based ASP system as operational knowledge has increased about the resulting produced fluid.

Based on early results on the project, incremental production can be achieved - it is simply a matter of determining how much and at what cost. Husky is dedicated to technically and economically advancing the process to justify additional ASP floods in suitable reservoirs in Alberta.   Husky and the Alberta Department of Energy have invested resources to improve understanding of how to increase oil recovery and reduce costs through facility optimization and ASP chemical system advancement. Husky would like to proactively justify more green chemistry based ASP projects to demonstrate environmental performance can be improved while still achieving economic goals.