SPE 39921


Abstract

The Pekisko formation in the Bigoray field in central Alberta is an oil-bearing dual permeability/porosity dolomite. A portion of the reservoir has permeabilities in the range of 1-2 Darcy and porosities approaching 25-30% while the rest of the reservoir features 10-30 milliDarcy average permeabilities, 8-12% porosities and low initial water saturation. It is suspected that both rock types contribute to the flow of oil.

Drilling of horizontal wells in the Pekisko formation offers technological challenges in terms of field development and formation impairment. Damage mechanisms for the two rock types are expected to be different yet need to be addressed in one drilling fluid system. Open hole completion/stimulation to repair any formation damage and the avoidance of underlying water adds to the drilling challenges.

This paper describes the results of laboratory formation damage studies to both identify damage mechanisms and evaluate which drilling fluid system to be used in the horizontal well section. The higher permeability/porosity dolomite core plugs were damaged by solids plugging while aqueous phase trapping and solids plugging were responsible for damage in the lower quality rock.

A total of eight horizontal wells have been drilled in the field as of December 1997. The horizontal wells were drilled with three types of drilling fluids: oil, oil-soluble resin and a carbonate bridging system containing an aqueous phase trap reduction agent. The horizontal wells drilled with the carbonate/aqueous-phase trap drilling fluid system had better oil production and less water than the wells drilled with the other drilling fluids. Discussion will also focus on stimulation of those horizontal wells that were damaged in the drilling process.

Introduction

The Bigoray field in west Central Alberta was discovered in 1962. The estimated reserves from the Pekisko formation are 5400 10^3m^3 of oil and 2574 10^6m^3 of gas. Only a meager 3.5% of the original oil in place has been produced to date. Vertical wells drilled into the pool typically show declining oil production and increasing water cut over their producing lifetime.

Saxon Petroleum has embarked upon a series of horizontal wells in the Pekisko formation to increase oil production and minimize water handling at surface. This paper describes the challenges of drilling open hole horizontals in a dual permeability/porosity dolomitic reservoir. Topics covered include geological background, vertical well performance, formation damage issues and related core flow studies, vertical well performance and the drilling, completion and production histories of selected horizontal wells.

Geological Description

The Bigoray field is located 100 kilometers west of Edmonton in west central Alberta (Figure 1). The larger Pembina field lies to the south of the Bigoray field. The Pekisko oil and gas pool covers approximately 3000 hectares and contains 29 wells. A smaller subset of this pool is located directly to the west of the main Pekisko field and is approximately 500 hectares in size (Figure 2). This smaller pool, which is the focus of this paper, may be separate from the main pool since less reservoir pressure depletion has occurred in this smaller sub-section.

Reservoir Description: The Bigoray Mississippian oil and gas pools are situated on the up dip, north/south trending, and truncated edge of the Pekisko formation. The Pekisko is underlain by the shaly and silty dolomite laminates of the Mississippian Banff formation and overlain unconformably by the mudstones and siliceous limestones of the Jurassic
Nordegg formation. Figure 3 depicts a cross section of the formations as taken from the cross section line indicated on Figure 2. A definite oil water contact lies to the western edge of the pool with the gas cap located to the more easterly portion of the pool. Some fracturing of the upper portions of the Pekisko are evident. The gross thickness of the Pekisko oil dolomite varies from zero to +20 meters.

Rocks of the Pekisko formation consist of low to excellent reservoir quality, fine to coarse crystalline dolomites. Thin section petrology shows the dolomites originated from coarse to fine echinoid and peloidal lime grainstones that formed under shallow, moderate to moderately high energy shoaling conditions. The reservoir evolved through a moderately complex paragenesis that involves the following stages:

1. Deposition as peloidal and skeletal lime grainstones under moderate to moderately high energy shoaling conditions.
2. Eogenetic to early mesogenetic, incomplete cementation by calcite. Moderate to significant occlusion of intergranular porosity. In zones where intergranular porosity was completely cemented by calcite there is very little subsequent enhancement of porosity.
3. Mesogenetic dolomitization of the limestone, formation of some biomoldic and cement moldic porosity. Some enhancement of intergranular porosity.
4. Probable chemical compaction and recrystallization of dolomite, incomplete cementation of porosity by dolomitic cements.
5. Fracturing and emplacement of calcite cement. Partial replacement of dolomite by calcite. Moderate to significant occlusion of highly modified intergranular porosity by calcite cements.
6. Late stage dissolution of calcite with significant enhancement of porosity. Formation of solution enhanced intercrystalline and moldic pores. Minor occlusion of solution modified porosity by late stage dolomite cement.

The upper portion of the Pekisko in the Bigoray area appears fractured and in some areas brecciated, as a result of insitu collapse of the strata. The fractures may be sealed, open or infilled with silicified carbonates (chert), black mudstones, claystones and/or argillaceous carbonate.

Cores and Petrography: An attempt to cut a core in the horizontal section at 16-11 resulted in a recovery of only two meters of predominantly milled and fractured core. The core consisted of medium crystalline dolomites and pinpoint vugs. Petrographic work showed other constituents including bitumen (1 – 6%), minor clays and traces of quartz and pyrite. Porosity ranged from 8 – 13.5% and permeabilities from 1.0 milliDarcy to 2.0 Darcy.

A more successful core was cut in the vertical 4-11 well. Eighteen meters of core were cut and recovered, including 0.6 meters of the overlying Nordegg and 1.65 meters of the underlying Banff. Porosity by conventional core analysis ranged from 5.1 – 30.3% and permeabilities from 1.5 milliDarcy to greater than 3 Darcy. Small amounts of bitumen (1 – 7%), minor clay fractions, some calcite cement and anhydrite are present in the vugs and small randomly oriented fractures.

7-12 Vertical Well
Drilled in 1978, the 7-12-52-9 W5 vertical well is a typical producer from the Pekisko A pool. The well was drilled to TD of 2531 m and plugged back to 1985 m to produce from the Pekisko interval (1954-1972 m). The Pekisko interval was drilled with CaCl2 floc water and then mudded-up to a simple gel-chemical drilling fluid. Perforations were originally shot between 1969.5 to 1972.5, squeezed with 1m\(^3\) of 15% HCl and 6m\(^3\) of 28% HCl. Additional perforations were shot in November 1981 between 1958-1961 m and treated with acid as above. In March 1996, the perforations were squeezed with alternating treatments of asphaltene-wax modifier and 15% HCl.

Average daily fluid production from 7-12 is shown in Figure 4. The overall trend has been towards a decrease in oil production from an initial high of 21 m\(^3\)/day to the current 1997 average of 5.5 m\(^3\)/day. Water production has increased steadily to a current water cut of approximately 75%. Chemical stimulations in 1981 and 1996 described above provided only minor boosts in oil production and did not affect the water cut. An increase in oil production in 1981 corresponded to repairs on rods and downhole pump. To the end of September 1997, cumulative production from 7-12 was 51,000 m\(^3\) of oil, 74,000 m\(^3\) of water and 10 10\(^6\) m\(^3\) of gas.

With the high water cuts and declining production rates of 7-12, the decision to drill a series of horizontal wells in the pool was undertaken. It was anticipated that the horizontal wells would increase oil production due to the greater amount of Pekisko drilled, and that water production would be minimized due to lower drawdown pressures.

A second vertical well, 4-11 was recently drilled in 1997. Figure 5 shows the log of water saturation, porosity and rock lithology over the open-hole Pekisko interval. Water saturation averages 30-50% with low (< 5%) and high (70%) saturations at the top and bottom of the Pekisko, respectively.

Formation Damage Issues and Core Flow Work
As described in the geological section, the Pekisko dolomite is a dual permeability/porosity system. The high permeability/porosity network is thought to be primarily responsible for flow channels of fluids while the storage of oil is more concentrated in the lower permeability/porosity dolomite. As such, it is important in the design of drilling fluids to minimize damage in both types of flow systems. An understanding of the most likely damage mechanisms in each type of permeability/porosity rock needs to be completed so that a single low-non damaging drilling fluid can be designed.

Lower Permeability/Porosity Considerations. A major
damage mechanism of clean low permeability/porosity dolomitic rocks is due to mud solids plugging and aqueous phase trapping (or water block). Damage due to mud solids plugging in low permeability reservoirs can also be substantial in horizontal wells. Fine drilled solids can penetrate into the formation and become lodged in pores and pore throats, thereby producing a barrier to flow. Typically, bridging systems are used to minimize the amount of solids invasion into the wellbore and in carbonates an acid soak is used to remove the external and near wellbore filter cakes.

Table 1, taken from Bennion et al, describes the expected severity of damage due to aqueous phase trapping in rocks with various permeabilities and initial water saturations (Wsi).

Aqueous phase trapping, or water block, is damage caused by the irreversible uptake of water into an undersaturated formation. The uptake of water to the irreducible water saturation invariably leads to a reduction in the permeability to oil and subsequent formation damage results. The low permeability/porosity Pekisko system with average unstressed air permeabilities of 10-30 mD and Wsi of 18% has an estimated damage due to aqueous phase trapping of mild severity.

An aqueous phase trap reduction agent (APTRA), which will prevent/minimize the uptake of water in undersaturated reservoirs was used in the drilling of a number of Pekisko horizontal wells. Damage due to aqueous phase trapping is decreased when the surface tension of the bound water phase is decreased, therefore minimizing the uptake of water in the undersaturated formation.

Higher Permeability/Porosity Considerations. The predominant damage mechanism in 1-2 Darcy, 25-30% porosity Pekisko rock is due to plugging from drilled solids and mud fines. The larger pore sizes will allow for a greater penetration of both solids and whole mud deeper into the formation. In the Pekisko formation where flow of oil through the high permeability/porosity network is essential, a loss of solids and/or whole mud could lead to significant impairment to hydrocarbon flow.

Properly designed bridging systems in the higher permeability/porosity Pekisko should ensure that any formation damage due to solids or whole mud is confined to near wellbore. The design of bridging systems in high permeability formations is often difficult to accomplish because of the large diameter pores and pore throats. A bridging system with a wide variety of sized bridging agents, sufficient quantities of bridging materials along with an excellent filter cake building agent is required to seal efficiently against the wellbore surface.

A series of dynamic core flow studies under downhole pressure and temperature conditions were undertaken to determine the correct bridging system for the high permeability/porosity Pekisko dolomite. The results are shown in Table 2.

The carbonate polymer and oil-soluble resin fluids were both designed as bridging systems to limit fluid flow into the core and also to be readily removed under inflow conditions to oil. In the core flow tests, the carbonate polymer system proved the least damaging with essentially no change in inflow permeability to crude oil after exposure to the drilling fluid. A 43% reduction in permeability was observed with the oil-soluble resin fluid system.

A petroleum distillate with properties similar to diesel fuel, was also damaging to the high permeability/porosity core plugs. In theory, the distillate should be able to prevent aqueous phase trapping induced formation impairment since no water is present to be absorbed by the formation. Protection of the lower permeability/porosity Pekisko with a hydrocarbon-based fluid should occur. The tests in these higher permeability core plugs were undertaken to see if damage would occur in a non-bridging system. Petroleum distillate used in an overbalanced pressure state, with only rock fines present, had a 25% reduction in permeability to crude. The underbalanced petroleum distillate test, where net flow was from the core into the circulating distillate, also showed damage although no solid particles were theoretically injected into the core plug face. The damage mechanism for using the petroleum distillate in an underbalanced mode, where 32% damage was noted, has not been confirmed.

Emulsions. Simple bottle tests of shaking Pekisko crude with drilling fluids (polymer carbonate or oil-soluble resin) or their filtrates showed a minor tendency to form emulsions. The whole muds were more prone to forming stable emulsions. Additions of a variety of demulsifiers types to the water based muds prevented emulsion formation. Demulsifiers were added to the water-based muds during both the core flow tests and drilling of the horizontal wells.

Horizontal Wells
Beginning in August 1996 and continuing to December 1997, Saxon Petroleum has drilled eight horizontal wells in the Bigoray Pekisko field. Four of these wells were drilled with an oil-soluble resin fluid in the horizontal section. Three were drilled a polymer-carbonate system containing an aqueous phase trap reduction agent (APTRA) and one well drilled with an overbalanced petroleum distillate. Six of the eight wells are currently on production (Table 3).

The formation damage studies discussed in the previous section were conducted following the drilling of four wells where oil-soluble resin was used. The polymer-carbonate-APTRA and the distillate wells were drilled post coreflow work.

The following discussions will focus on three representative wells in the 52-9 W5 section, namely 16-11, 12-11 and 16-10. These three wells were chosen since they have longer production histories than some of the other horizontals, were drilled with different drilling fluid systems and represent interesting geological comparisons. The location of the horizontal wells are shown in Figure 2.
roughly parallel horizontal wells drilled in north-south direction. These wells were considered good offsets to each other since they are physically close to each other and are drilled in similar directions. It was expected that the two wells would contact similar rock quality. The 12-11 well had a 485 m horizontal interval and was drilled with the oil-soluble resin fluid. The 16-10 well with a horizontal length of 630 m was drilled with the APTRA-polymer-carbonate drilling fluid system. The following discussion will focus on the drilling and completion practices for these wells, the geological similarities/differences and the production data.

**Drilling.** The 12-11 well drilled with the oil-soluble resin experienced losses of approximately 50-60 m$^3$ of whole mud throughout the horizontal interval. Losses generally averaged 3-4 m$^3$/day in the Pekisko. No other difficulties occurred in the drilling process. The well was drilled in January 1997.

Drilling of the 16-10 well, in March 1997, proceeded with no losses in the horizontal section. The carbonates used as bridging agents were similar to those used in the coreflow experiments, a mixture of three different sizes. The particle sizes of the added bridging agents from 12-11 and 16-10 are given in Table 4.

**Completion Strategy.** A bridge plug was set in the vertical section of the 12-11 well and the mud displaced with oil. The resin mud in the horizontal section of the well was then blown utilizing coiled tubing and N$_2$. A total of 78 m$^3$ of mud and oil were recovered. The well initially flowed oil on swab tests at 8-10 m$^3$/hr with a 10-15% water cut. A 69 mm tubing pump was then installed in the 73 mm production tubing.

Completion treatment of 16-10 was with a nitrified acid wash. The well was underbalanced acid washed with 28 m$^3$ of nitrified 15% HCl from heel to toe and reversing from toe to heel. The volume of acid used in 16-10 was sufficient to dissolve the carbonate bridging particles. A 69 mm tubing pump was also installed.

**Logs.** Figures 6 and 7 depict the log information for the horizontal sections on 12-11 and 16-10 respectively. Included in the figures are the porosities to hydrocarbons and water along with combined lithologies of the horizontal intervals. Overall, the log from 12-11 shows greater hydrocarbon porosity than at 16-10 and fairly good porosity throughout the entire 470 m horizontal wellbore. The Pekisko rock at 12-11 has a very high dolomitic content with small amounts (<5%) of quartz (chert). One shaly interval is evident from 2310-2325 mMD. The hydrocarbon porosity over this interval does not seem to be impacted and is still greater than 10%.

In contrast to the 12-11 log, the hydrocarbon porosity is much less at 16-10. Coupled with the higher porosity to water in 16-10, the overall quality of the Pekisko rock is much poorer at 16-10 than at 12-11. The Pekisko formation at 16-10 has a quartz content averaging 10-15%, approximately twice that seen in 12-11.

Production at 16-10 is likely limited to the first 80 meters and final 400 m of drilled hole. Approximately 130 meters from 2170-2300 mMD has large concentrations of shale and calcite interspersed in the dolomite and subsequently low hydrocarbon porosities. Little to no production is expected from this section. Minor shale stringers are found in the first 400 m of drilled hole, however, hydrocarbon porosities are still greater than 10%.

**Production data.** Production data from 12-11 and 16-11 are shown in Figure 8. The production from 12-11, drilled with the oil-soluble resin mud, produced an average of 50-60 m$^3$/day of oil over the first three months of production. Oil production has steadily decreased since then and averages 1 m$^3$/day through September of 1997. During the same period of decreasing oil production, the water cut has increased from 47% initially to the September 1997 level of 84%. The average gas-oil ratio over the first nine months of production has averaged 430 with the range being 230 to 690. Compare to the 7-12 vertical production in Figure 5, the horizontal well 12-11 is currently producing three times the amount of oil. The water cut at 12-11 is approximately 10% higher than at 7-12, even after the short time that 12-11 has been in production.

Oil production from 16-10 has been more uniform than from 12-11 and to date has not experienced the decline observed at 12-11. The average daily oil production at 16-10 and 12-11 over their entire production history has been 38.5 m$^3$/day and 34.4 m$^3$/day, respectively. The water cut at 16-10 has averaged only 22% with the only real increase in the last month where production data is available (September 1997). Water cuts have previously ranged from 2 to 21%. The gas-oil ratio at 16-10 has averaged 281 with a range of 57 to 610.

The average daily oil production from these two horizontals over their production histories are approximately seven times that of the 7-12 current vertical production. However, the current oil production from 12-11 is only three times that of the 7-12 vertical while the 16-10 well is still producing seven times that of 7-12. The increasing water cut and decreasing oil production at 12-11 is a concern.

Given the poorer production profile and better quality rock at 12-11 horizontal compared to 16-10 horizontal, the 12-11 well is considerably more damaged than is the 16-10 well. The loss of whole mud at 12-11 into the Pekisko dolomite has likely impaired the movement of oil within the reservoir. In addition, further impairment may have occurred at 12-11 since no APTRA was used on this well.

To date, no Skin value determinations have been made on either the 12-11 or 16-10 well. With the dual permeability system present in the wells, measurement of Skin would be difficult. A series of flow tests over specific intervals would be required to measure the damage in each of the wellbores. The 12-11 well is suspected of having a larger Skin value than the 16-10 well given the poorer production and better log seen at 12-11.

**16-11 Horizontal.** The 16-11 horizontal well was drilled in November of 1996 using an oil-soluble resin mud system. The horizontal interval was 793 m in length and drilled updip with an average hole angle of 91° from vertical. As seen in Figure 2, the 16-11 well was drilled in a west to east direction and perpendicular to the 12-11 and 16-10 wells. Drilling of 16-11 perpendicular to the 12-11 and 16-10 wells provided
different direction in which to contact the Pekisko permeability and porosity. In the event that fractures do play a part in the production of oil from the Bigoray pool, the west to east well path at 16-11 will provide a different orientation to contact the fractures.

**Drilling.** The 793 m horizontal leg was drilled in 12 days, including time spent cutting two horizontal cores. Total losses from the resin system amounted to 150 m$^3$ of whole mud. No other drilling problems were reported while drilling the horizontal section.

**Completion.** An oil-soluble resin breaker was placed in the horizontal section of 16-11 following drilling and was allowed to contact the filtercake for a 12 hour period. The well was blown out with $N_2$ and then underbalanced acid washed with nitrified 15% HCl from heel to toe and reversing from toe to heel. The purpose of the acid wash was to remove polymeric agents from the filter cake and to provide some near wellbore stimulation of the Pekisko dolomite. A 69 mm tubing pump was then installed in the 73 mm production tubing. Artificial lift was installed in January of 1997 with repairs conducted in August of 1997.

**Logs.** The horizontal logs from 16-11 are shown in Figure 9. The 16-11 log provides an example of the fractured/brecciated areas contained within portions of the Pekisko as evidenced by the high quartz (chert) and shale content within the interval 2095 – 2165 mMD. Intermittent stringers of quartz within the dolomitic network continue to 2250 mMD. Hydrocarbon porosities over this interval average five to eight percent. The remainder of the 570 m horizontal leg is predominantly dolomite with some shale and/or quartz lenses. Hydrocarbon porosities resemble those of 12-11 log (Figure 5) with average porosity of 10% and some sections of 20-25% porosity. The porosity to water in 16-11 log is greater than at 12-11 and similar to that exhibited at 16-10.

**Production.** The 16-11 well has been a relatively poor producer of oil (Figure 8). Average production over the first nine months has been 9.0 m$^3$/day of oil with an average water cut of 65%. The production rates to date have been relatively steady over the life of the well. The GOR has averaged 1620, the highest of the horizontal wells discussed here.

This well is a disappointment in the volume of oil and daily rate recovered to date, especially given the good rock quality seen on the horizontal logs. Oil production is much less than from 16-10 and 12-11 wells and is only twice that of the current production from the eighteen year old 7-12 vertical well. The cause of the poorer production is less clear. Formation damage due to the oil-soluble resin drilling fluid may be fully or partly responsible. Similar to 12-11, the loss of substantial volumes of whole mud and/or the absence of an APTRA may have lead to reduced permeability and flow to oil. The directional placement of the well in a west to east direction may also be affecting production. The better horizontal producers, 12-11 and 16-10 run in a roughly north to south direction.

**Conclusions**

1. Core flow studies need to be conducted on new horizontal projects prior to drilling. The studies are especially important in rocks where multiple damage mechanisms are possible.

2. The APTRA-polymer-carbonate system proved less damaging than the oil-soluble resin system in drilling the Pekisko horizontal wells.

3. The production from wells at 12-11 and 16-11 are poorer than anticipated, especially given the high quality rock seen on the horizontal logs.

4. The Pekisko dolomite in Bigoray can be damaged by solids and/or fluid invasion. Damage due to aqueous phase tapping is also suspected in the lower permeability, lower water saturated dolomitic fraction.

5. The directional placement of the horizontal wellbore may have some impact on the production of hydrocarbons and water from the well. Further wells need to be drilled in order to ascertain whether the direction of the well impacts upon production.

**Acknowledgements**
The authors would like to thank the managements of their respective companies for permission to publish the information contained within this paper.

**References**


### TABLE 1. AQUEOUS PHASE TRAP SEVERITY PREDICTION *

<table>
<thead>
<tr>
<th>Initial Permeability to Air (mD)</th>
<th>Swi &lt; 10%</th>
<th>Swi 10-20%</th>
<th>Swi 20-30%</th>
<th>Swi 30-50%</th>
<th>Swi &gt; 50%</th>
</tr>
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<tbody>
<tr>
<td>k &lt; 0.1 mD</td>
<td>Severe</td>
<td>Severe</td>
<td>Moderate</td>
<td>Moderate</td>
<td>Mild</td>
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<tr>
<td>0.1 &lt; k &lt; 1 mD</td>
<td>Severe</td>
<td>Moderate</td>
<td>Mild</td>
<td>Mild</td>
<td>Slight</td>
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<tr>
<td>1 &lt; k &lt; 10 mD</td>
<td>Severe</td>
<td>Moderate</td>
<td>Mild</td>
<td>Slight</td>
<td>Unlikely</td>
</tr>
<tr>
<td>10 &lt; k &lt; 100 mD</td>
<td>Moderate</td>
<td>Mild</td>
<td>Unlikely</td>
<td>Unlikely</td>
<td>Unlikely</td>
</tr>
<tr>
<td>100 &lt; k &lt; 500 mD</td>
<td>Mild</td>
<td>Mild</td>
<td>Unlikely</td>
<td>Unlikely</td>
<td>Unlikely</td>
</tr>
<tr>
<td>500 mD+</td>
<td>Slight</td>
<td>Unlikely</td>
<td>Unlikely</td>
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* After Reference # 4

### TABLE 2. CORE FLOW DAMAGE STUDY RESULTS

<table>
<thead>
<tr>
<th>MUD TYPE</th>
<th>INITIAL PERMEABILITY *</th>
<th>REGAIN PERMEABILITY **</th>
<th>% PERMEABILITY CHANGE</th>
<th>NET OVERBURDEN</th>
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</thead>
<tbody>
<tr>
<td>Carbonate – Polymer</td>
<td>75.3 mD</td>
<td>76.7 mD</td>
<td>+2</td>
<td>6200 kPa</td>
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<tr>
<td>Oil–Soluble Resin</td>
<td>74.3 mD</td>
<td>42.3 mD</td>
<td>-43</td>
<td>4625 kPa</td>
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<tr>
<td>Distillate – underbalanced</td>
<td>122.8 mD</td>
<td>83.1 mD</td>
<td>-32</td>
<td>&lt; 0 kPa</td>
</tr>
<tr>
<td>Distillate - overbalanced</td>
<td>45.9 mD</td>
<td>34.2 mD</td>
<td>-25</td>
<td>3000 kPa</td>
</tr>
</tbody>
</table>

* - at 70 °C, 30 MPa net overburden pressure, mud overbalance 3000 – 6000 kPa
** - 500 – 1000 kPa drawdown pressure
♦ - mud overbalance < 0 kPa

### TABLE 3. SAXON LOCATIONS AND CUMULATIVE PRODUCTION IN BIGORAY 52-09 W5 FIELD

<table>
<thead>
<tr>
<th>WELL LOCATION</th>
<th>START OF PRODUCTION</th>
<th>MUD SYSTEM</th>
<th>CUMULATIVE OIL PRODUCTION</th>
<th>CUMULATIVE GAS PRODUCTION</th>
<th>CUMULATIVE WATER PRODUCTION</th>
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</thead>
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<tr>
<td>6-14</td>
<td>October ’96</td>
<td>Oil-soluble Resin</td>
<td>4418 m³</td>
<td>6447 10³ m³</td>
<td>3743 m³</td>
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<tr>
<td>16-11</td>
<td>December ’97</td>
<td>Oil-soluble Resin</td>
<td>1738 m³</td>
<td>2849 10³ m³</td>
<td>3140 m³</td>
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<tr>
<td>12-11</td>
<td>January ’97</td>
<td>Oil-soluble Resin</td>
<td>8066 m³</td>
<td>3485 10³ m³</td>
<td>18325 m³</td>
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<tr>
<td>9-11</td>
<td>April ’97</td>
<td>Oil-soluble Resin</td>
<td>5397 m³</td>
<td>2055 10³ m³</td>
<td>2279 m³</td>
</tr>
<tr>
<td>16-10</td>
<td>April ‘97</td>
<td>APTRA-polymer-carbonate</td>
<td>7037 m³</td>
<td>1981 10³ m³</td>
<td>1993 m³</td>
</tr>
<tr>
<td>13-1</td>
<td>August ’97</td>
<td>APTRA-polymer-carbonate</td>
<td>348 m³</td>
<td>88 10³ m³</td>
<td>1439 m³</td>
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<tr>
<td>11-1</td>
<td>Not on production</td>
<td>APTRA-polymer-carbonate</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>6-11</td>
<td>Not on production</td>
<td>Petroleum distillate</td>
<td>N/A</td>
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TABLE 4. PARTICLE SIZES OF BRIDGING AGENTS IN WATER-BASED BRIDGING SYSTEMS

<table>
<thead>
<tr>
<th>WELL</th>
<th>MUD SYSTEM</th>
<th>BRIDGING AGENT</th>
<th>PARTICLE SIZE</th>
<th>CONCENTRATION</th>
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<tr>
<td></td>
<td></td>
<td></td>
<td>MINIMUM</td>
<td>MAXIMUM</td>
</tr>
<tr>
<td>12-11</td>
<td>Oil-soluble resin</td>
<td>Medium</td>
<td>1 micron</td>
<td>150 microns</td>
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<tr>
<td></td>
<td></td>
<td>Fine</td>
<td>1 micron</td>
<td>30 microns</td>
</tr>
<tr>
<td>16-10</td>
<td>APTRA-polymer-carbonate</td>
<td>“325” CaCO₃</td>
<td>1 micron</td>
<td>88 microns</td>
</tr>
<tr>
<td></td>
<td></td>
<td>“0” CaCO₃</td>
<td>1 micron</td>
<td>500 microns</td>
</tr>
<tr>
<td></td>
<td></td>
<td>“Super” CaCO₃</td>
<td>88 microns</td>
<td>840 microns</td>
</tr>
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Figure 1: Bigoray Location in Alberta

Figure 2: Well Locations in Smaller Pekisko Pool in Bigoray Field

Figure 3: West to East Cross Section of Smaller Pekisko Pool (Figure 2)
Figure 4: Production Data from 7-12 Vertical Well
Figure 5: Logs from 4-11 Vertical Well
Figure 6: Log Data from 12-11 Horizontal Drilled with Oil-Soluble Resin Mud (Part 1)
### COMPLETE EVALUATION SUMMARY

**Well:** SAXON BIGORAY 12-11-52-9W5

*Figure 6: Log Data from 12-11 Horizontal Drilled with Oil-Soluble Resin Mud (Part 4)*
Well: Saxon Bigoray 16-10-52-9W5

### Complete Evaluation Summary

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Spontaneous Potential Log</td>
<td>LSW log</td>
</tr>
<tr>
<td>Medium Induction Log</td>
<td>LSW log</td>
</tr>
<tr>
<td>Gamma Ray</td>
<td>Deep Induction Log</td>
</tr>
</tbody>
</table>

### Figure 7: Log Data from 16-10 Horizontal Drilled with APTRA-Polymer-Carbonate Mud (Part 1)
Figure 7: Log Data from 16-10 Horizontal Drilled with APTRA-Polymer-Carbonate Mud (Part 3)
Figure 8: Production Data from 16-10, 12-11 and 16-11 Horizontal Wells
Figure 9: Log Data from 16-11 Horizontal Drilled with Oil-Soluble Resin Mud (Part 1)
COMPLETE EVALUATION SUMMARY

Well: Saxon Bigoray 16-11-52-9W5

Figure 9: Log Data from 16-11 Horizontal Drilled with Oil-Soluble Resin Mud (Part 5)