



## All metal progressing cavity pumps deployed in SAGD

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### Abstract

The all metal progressing cavity pump (AMPCP), patented PCM Vulcain TM, has now been in use for 4 years in Enhanced Oil Recovery Methods, namely SAGD (steam assisted gravity drainage), CSS (cyclic steam stimulation), THAI (toe to heel air injection) and steam drive applications. Several papers have been issued, showing first the promising test bench characteristics of this pump, the first industrial version in operation in Canada, and the learning curve associated with run data and failures.

To date a total of 100 pumps have been deployed worldwide in various applications with the longest run time at over two years.

This paper will overview the run of an AMPCP in a SAGD application, showing the wide operating range in terms of production, the capability of handling varying downhole operating conditions such as bottom hole pressures, temperatures, and viscosity. It will also show the robustness of the system, with the pump remaining downhole during various steam and chemical stimulations, designed by Shell to reduce differential pressure between the injector and producer, ultimately, resulting in greater oil production and lower Steam Oil Ratio (SOR).

### Introduction

Among the estimated 170 billions barrels reserves of Canadian oilsands, 20% can be recovered by mining techniques where the reservoir depth is 90 meters or less. The remaining 80% of the resource has to be recovered in-situ (in place).

The existing methods involve cold/CHOPS production or thermal activation - whether steam (such as SAGD, CSS or steam drive), electrical heating (ET DSP electro thermal dynamic stripping process) or combustion (THAI) or solvent injection (VAPEX vapor extraction). Combination of those processes can be used as well, and several research projects may bring other innovative solutions in the near future.

To date the majority of active in-situ operations have used SAGD for their recovery methods. Key factors to promote the use of SAGD are:

- reservoir characteristics – vertical permeability has to allow for steam chamber growth and flow to the producing well; Sufficient cap rock to sustain bottom hole pressure needed to promote flow of bitumen;
- steam oil ratio, meaning less energy spent per barrel produced;
- recovery factor, leaving minimal quantity of oil in the reservoir when the well is abandoned.

Shell's Orion field, shown in Figure 1, is located in Cold Lake, AB. The case story of Pad 105 producing well No.1 (P105 P1) using the high temperature package based on the AMPCP is presented hereafter, associating steam and chemical stimulation in SAGD.

## Reservoir characteristics

The lower Cretaceous Clearwater Formation was deposited during a major transgression (flooding) of the Western Canadian Basin. As the seas advanced and flooded the paleotopography (generally to the south/southeast) the shorelines were dominated by tidal currents; leading to deposition of a variety tidal deposits. Much of the reservoir is fine to medium grained sand beds that contain a mixture of thin mud beds (1-4 cm) and zones of mud rip-up clasts. A small percentage of the sands have a carbonate cement that formed during early burial.

The reservoir has an oil viscosity of ~75,000 cPo at reservoir temperature (16°C). The virgin reservoir pressure is below hydrostatic, has an initially thought 1-5 Darcy permeability, 33% porosity, 70% oil saturation, and 10 API oil at a depth of 400m TVD.

## SAGD Operation

Primary recovery from the Orion field is steam assisted gravity drainage (SAGD). In Orion two horizontal wells are drilled together, an injector-producer wellpair, with about 5 m of vertical separation and little to no horizontal offset. The upper well injects steam to heat the surrounding bitumen, in the form of a steam chamber, to lower the bitumen's viscosity. The bitumen drains to the producer, shown in Figure 2. The initial static differential pressure between the injector-producer is theoretically 50 kPa; 10 kPa/m (water head) at 5 m separation. Allowing for some natural heterogeneity, friction, etc. in a dynamic situation, a differential pressure of ~300 kPa is expected and perfectly acceptable. Orion, however, can see differential pressures of up to a few thousand kPa.

In natural lift, P105 P1 was completed with a short and long tubing string. This allowed for well circulation and production from the heel or toe. When converted to artificial lift, shown in Figure 3 and 4, a pumped multi-mode Distributed Temperature System was installed to monitor subcool and well inflow.

## High temperature package characteristics

The completion of a well equipped with the high temperature PCM Vulcain TM package is very similar to conventional downhole elastomer progressive cavity

pump (PCP's) for cold production. The key differences are:

- the all metal rotor and stator, able to withstand a broad range of static and dynamic temperatures and viscosities (up to 350°C, 660°F),
- the high temperature Oryx sealing system at surface,
- wellheads designed for high temperature applications, including polished rod blow out preventer, and blind rams for work-overs.

## All metal pump and downhole tools

Elastomer PCP's were introduced as an artificial lift solution in the 1980's for wells with heavy and abrasive oil. Ever since, technical progress has been made regarding chemical compatibility, temperature range, and abrasion resistance to fit heavy to light oil with a fair run life. Still, as a polymer, the intrinsic limitations are still present:

- Expansion coefficient makes it impossible to run the same pump over a wide range of temperature,
- Mechanical properties of traditional elastomers tend to break down over 150°C.

By the mid 80's thermal recovery of the Alberta oil sands gained popularity. Elevated temperature and pressures were beyond the operating limit of conventional elastomer PCP's.

## All metal progressive cavity pump

The patented PCM Vulcain TM all metal progressing cavity pump, shown in Figure 5, consists of a helical rotor, and a metal stator made up of multiple hydroformed elements. Apart from the innovative manufacturing process of the stator, the core characteristics of the metal pump are:

- the thermal expansion coefficient of the stator is equal to the rotor's so that the pump characteristics remain consistent over a wide temperature range (40 to +260°C),
- the alloys used for rotor and stator are corrosion resistant to H<sub>2</sub>S, CO<sub>2</sub>, and aromatics which can be troublesome for conventional elastomer PCP's,
- additionally, the metal pump has proven resistant to external chemical stimulations.

Although the AMPCP does not have the same interference fit between the rotor and stator as an elastomer PCP, the efficiency is still adequate as the fit can be precisely adjusted using the patented hydroforming process used for manufacturing. The AMPCP's are tested with water to ensure volumetric efficiency, friction and dynamic torque are all within specification.

The pump model used at Shell Orion is the 220V750 (220m<sup>3</sup>/day at 100 rpm @ 0 Head, “V” meaning PCM Vulcain TM, and 750 m lift capability of water column, ~7.5 MPa) - see pump performance test in Figure 6. Bench tested with water (5 cP), the new pump performed @ 70% volumetric efficiency at 300 rpm and full head (7.5 Mpa); the power consumption in these conditions equals 80kW.

The following section will further describe the downhole completion shown in Figure 3.

#### Downhole tools – tubing string

- Intake sub :

An intake sub consisting of a weighted eccentric mandrel that orientates to the low side of the horizontal to draw more liquid than gas.

- Torque anchor :

As per conventional PCP completions, the high temperature package includes a torque anchor. As the rotor is turned in the stator, torque is applied to tubing string which can cause connections to back off. The anchor is installed below the pump to prevent rotation of the tubing string. The tool design allows for additional guide/instrumentation strings and accommodates the restricted ID wellheads that are common in SAGD operations

- Tag bar :

A depth reference used to space out rod strings, as the string will stretch when temperature and differential pressure is applied to the pump.

#### Downhole tools – rod string

Continuous rod strings are used at Shell Orion. This allows for rods to be run in wells with dogleg severities over 13°/30 m. To date, no rod-tubing issues have arisen.

The rest of the string is comparable to an elastomer PCP completion:

A 3m or 7.62 m handling rod is installed to allow for the eccentric motion of a PCP rotor, and the use of a polished rod 1.5 to 3m longer than the rotor to allow for tubing to be flushed with water, produced fluid or steam. The polished rod also provides a smooth sealing surface for the high temperature seal.

#### PCP Surface Equipment

Surface equipment consists of a PCP drivehead capable of up 125 HP electric motors, a surface seal rated for thermal operations pressure and temperature, and a variable frequency drive to increase production flexibility and monitor pump performance.

#### Drivehead

The drivehead being used at Orion utilizes a 100 HP electric motor, with belts and sheaves to turn the rod string, approximately 340 RPM @ 60 Hz. Bearing capacity is 11.6 tons.

#### High Temperature Surface Seal

The high temperature surface seal, shown in Figure 7, has been a critical part in the high temperature PCP package, for both the environmental and safety consequences that would accompany a leak at surface. The surface seal is rated to 315°C at a dynamic sealing pressure of 3,500 kPa, and a static sealing pressure of 13,800 kPa.

To date, reliability of the seal at site has been excellent. The seal typically runs 30 to 50°C cooler than flowline temperature of 200°C as it is separated by a 3 1/8” 3000# flanged connection.

Preventative maintenance is done on the seal every 6 to 8 months and rebuilt when a drivehead is removed from the well.

#### Variable Frequency Drive

A variable frequency drive (VFD) is used to control pump speed and production. The system gives a pump operating range of 85-510 RPM @ a frequency range of 15-90 Hz respectively.

The VFD is also used to monitor pump performance. Rod speed, amperage, rod torque, and well status are relayed back to a central monitoring system in real time.

### **SAGD operation and results – 105 P1**

P105 P1 began circulation in June 2008. After one month the well had a short shut-in followed by another three months of circulation. By this point inter-wellbore communication was confirmed and the well was ready for SAGD operations. Over the next year, the well began having difficulties producing fluids to surface (low bottom hole pressures while still being subcooled).

To help promote fluid lift, a pro-active artificial lift installation was commissioned in December 2009. Prior to artificial lift, the well had a constant pressure differential which was thought to be from the reservoir heterogeneity. Worth noting, this installation was part of an eight well conversion campaign; four AMPCPs and four electric submersible pumps. The intent was to compare the two technologies in order to decide what lift system was most ideal for Orion.

After recompletion, the well pair communication issues, i.e. pressure differential, grew. In the first 4 months of operation, the well had improved the steam-to-oil ratio (SOR) from 8.4 to 5.2, however, oil production was

diminishing, 14m<sup>3</sup>/day to 10m<sup>3</sup>/day. During this same time frame, the producer bottom hole pressure dropped from ~2,000kPa pre-lift to 900kPa with the injector pressure rising to 5,000kPa without inducing a steam breakthrough, shown in Figure 8. Clearly, a skin factor was impeding inflow.

In order to confirm the plugging, a lower cost alternative to promote communication was deployed: steam stimulations. Steam stimulations allow steam injection down the producer wellbore casing at pressures above the operating reservoir pressure to promote well pair communication. After completing a thorough safeguard, the stimulation was executed on April 21<sup>st</sup>, 2010, with the PCP stator and rotor in-hole. After 10 consecutive days of 260°C steam, shown by the peak in pressure on Figure 8, communication with the injector was re-established. After a short shut-in “soak” phase to allow the injected steam to reach subcool, the PCP was started with no signs of efficiency loss and the well re-gained communication with the injector.

Post steam stimulation the oil production increased to a peak of 34m<sup>3</sup>/day with a total flow average of 150m<sup>3</sup>/day and a drop to 4.6 SOR. The bottom hole pressure had increased from 900kPa to ~3500kPa. Unfortunately, throughout the summer and fall the producer bottom hole pressure slowly declined back to 900kPa. Even though the pump load was increasing with the drop in pressure, the AMPCP maintained efficiencies of 40 to 50% - see Figure 9.

In March, Shell kicked-off a thorough and systematic pressure differential study to understand the well communication loss. By the fall, a sustainable and cost effective well bore chemical stimulation that eliminated the pressure differential and re-established well communication was ready for trial on 105 P1.

On November 30<sup>th</sup>, the chemical stimulation was executed. The well was able to re-gain communication, produce the highest oil to date, 40 m<sup>3</sup>/day, drop to a 3.9 SOR and up-lifted ~170m<sup>3</sup>/day gross flow with 150m<sup>3</sup>/day cold water equivalent steam injection. A summary of the well performance can be found in Figure 10. Post stimulation, the AMPCP also proved its robustness by continuing with a strong 50% pump efficiency.

### **Pump Performance Summary:**

The AMPCP has now produced for 14 months with total gross flow rates varying from 70 to 250 m<sup>3</sup>/day for speeds ranging from 125 RPM to 170 RPM. The pump load has varied from 150 ft-lbs of torque to 1000 ft-lbs, shown in Figure 8. Bottom hole temperatures have ranged from 125°C to 260°C. While the operating conditions have varied significantly, an underlying

improvement in SOR, 8.4 pre-lift to 4.6 post-lift to 3.9 post chemical stimulation, can be linked to artificial lift.

As side note, to date, Orion has installed 12 AMPCPs with no failures to date (one pro-active pull for a liner re-completion). Figure 11 summarizes the run-times to date.

### **Conclusion:**

In summary, after 14 months of service where the well was steam stimulated, chemically stimulated, with varying operating speeds, pump loads, and fluid inflow rates, the AMPCP has proven its versatility and helped improved the well cash flow.

The high temperature package handled the wide range of operating temperature (and viscosity accordingly), from low to high intake and differential pressures. Speed adjustment enabled to fit production and well capability as downhole conditions varied. Due to low rotating speed no emulsion issues arose and run life performed by the equipment surpassed the original expectation of one year mean run life.

The innovative and unique process used by Shell showed how production can be optimized by combining steam and chemical stimulation.

### **Acknowledgement**

The authors wish to acknowledge the management of SHELL, PCM and KUDU Industries for their permission to publish this work and their unwavering support.

### **DEFINITIONS**

AMPCP: All Metal Progressing Cavity Pump

Subcool: the temperature of water is below the associated saturated temperature

Saturation: the temperature of water is at the associated saturated temperature

CSS: Cyclic Steam Stimulation

SAGD: Steam Assisted Gravity Drainage

PI05 P1: Pad 105, producer well 1

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2. JL.BEAUQUIN, G.CHALIER & F.NDINEMENU, TOTAL SA, L.LEMAY & L.SEINCE, PCM, S.JAHN KUDU, Metal PCP field trial pushes up pumping window for heavy oil hot production : Joslyn field case, a *WHOC 2008-498 paper presented at the 2008 World Heavy Oil Congress, held in Edmonton, Alberta, 10-12 March 2008*

Appendices :

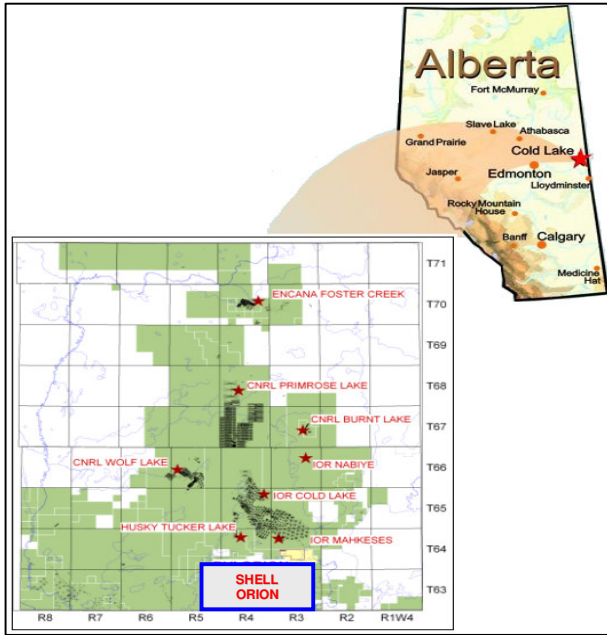


Figure 1: Shell Orion Location

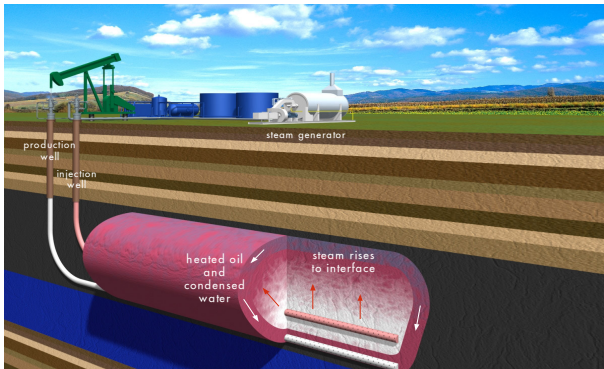


Figure 2: SAGD Schematic

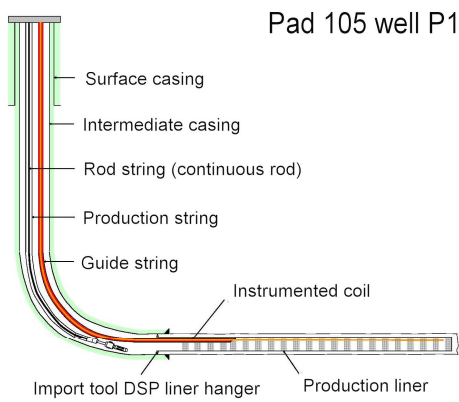


Figure 3: Well completion



Figure 4: Actual Surface Completion

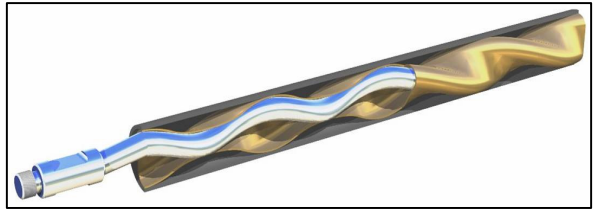


Figure 5: Progressing Cavity Pump Rotor in Stator

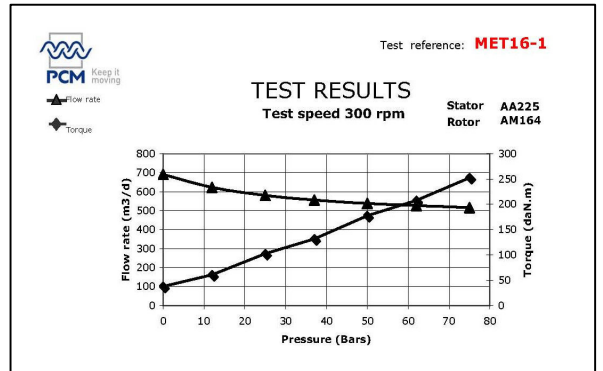


Figure 6: 220V750 performance test, on water at 5 cpo.

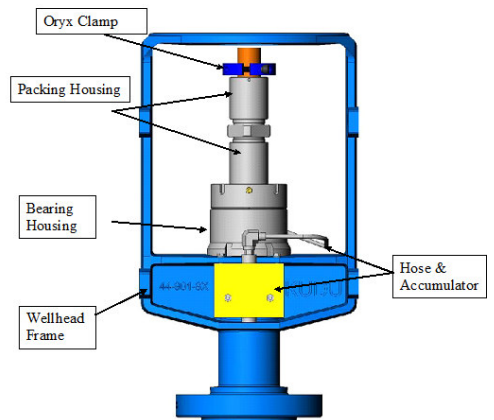


Figure 7: Drivehead Diagram

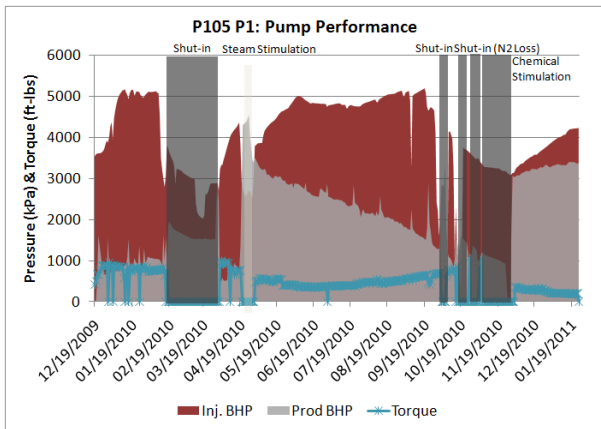


Figure 8: Bottom Hole Pressures through N2 purges with Torque

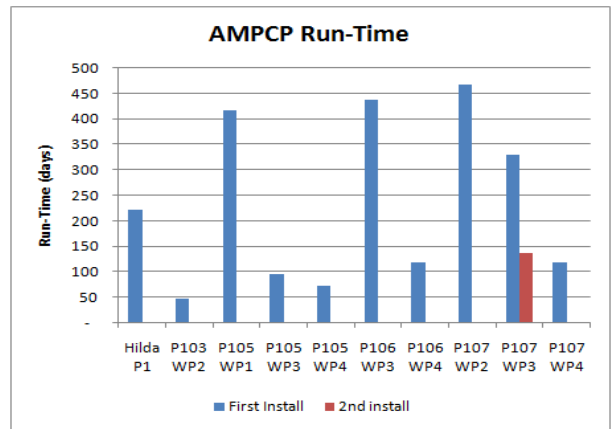


Figure 11: AMPCP Run-time

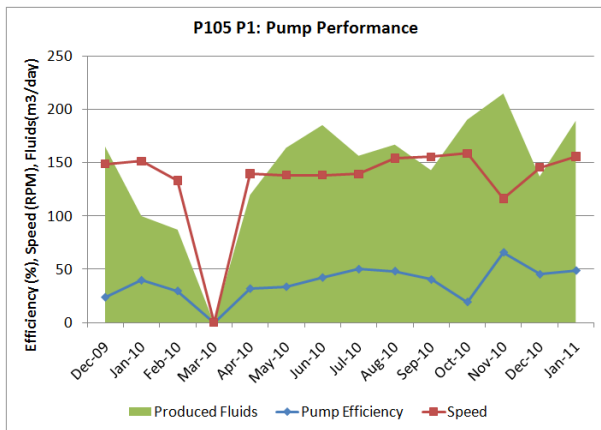


Figure 9: PCP Performance

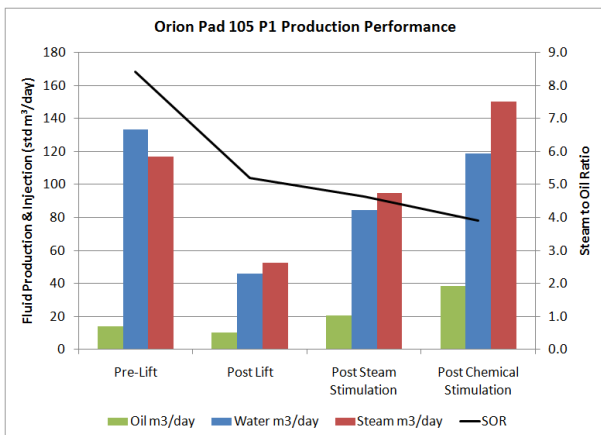


Figure 10: P105 P1 Production Performance