# Innovative Energy Technologies Program
# Project Annual Report Requirements

*SEPTEMBER 2010*

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# 1 Summary

Total E&P Canada Joslyn pilot project Phase 1 and Phase 2 began in the field in November 2003 with drilling operations. This pilot aimed to validate the feasibility of shallow SAGD (Steam Assisted Gravity Drainage). In 2004 and 2005 the oil was produced by using two types of artificial lift, a Sucker Rod Pump and an ESP (Electrical Submersible Pump). In 2006 production continued with the use of ESP's and reached a yearly high of ***62 $m^3$/d*** of bitumen. In 2007, well production decreased to 25 $m^3$/day by October 2007. The maximum bottom hole pressure of the well was reduced late 2007 to 1100kPa as the steam chamber grew. Additionally, the ESP pump was replaced with the PCP (Progressive Cavity Pump) to increase the production volumes. After the pump change, the production increased to 55 m3/day. In Fall 2008, heat trace was installed on the annulus gas line of the well to prevent casing gas freeze off in the winter. The length of the annulus gas line for Phase 1 is much longer than all other wells and this modification was a necessity for the operation. The goal of this pilot was to earn experience and increase knowledge of shallow SAGD mechanisms to operate and optimize future commercial projects.

After a full strategic review of Joslyn SAGD facility and given prevailing low production, it was decided to suspend the Joslyn SAGD operations effective the 5th February 2009. The Joslyn SAGD suspension was executed in seven (7) months. However, the oil production including production from the Phase 1pilot producer well IPI was completely stopped on March $27^{th}$., where the total Oil Production from phase 1in 2009 was 3376 $m^3$ of Bitumen. The two (2) months period from Feb 5 to March 31, 2009 comprised of depressurization of the steam chambers including Phase I pilot well pair. During this phase the well still produced, with virtually no steam injection, except for steam for heating purposes. Plant operations continued as normal with water disposal internally into existing disposal wells with any excess being disposed offsite at 3rd party facilities.

In July of 2009, the Joslyn Phase One well were suspended as per ERCB regulations and directives. The wells were flushed with fresh water containing a corrosion inhibitor pressure tested and secured.

## *1.1 Chronological activities*

The following are the main activities that took place on Phase 1 and Phase 2 in 2009:

- Feb 2009 – Steam injection was stopped. Production continued without injection.
- March 27, 2009 – last day of production.
- July 2009 – Phase 1 Production well – PCP rotor and rod string was removed and the stuffing box was replaced with a blind flange. The well heads were inspected and full wellhead maintenance service was performed complete with a pressure test to confirm integrity. Both the injection and production wells were flushed with hot water containing a corrosion inhibitor and anti freeze. The wells were then secured.

# 2 Pilot Data

## *2.1 Data submission*

### 2.1.1 Geology and geophysical data

#### *2.1.1.1 Producer & Injector well-pair*

As described in the 2005 report, the Phase 1 well pair was drilled before both slant observation wells, relying on logs and cores that were done previously on the heel and toe area of the horizontal wells. This first data collected showed good reservoir quality, and the drilling trajectories of the well pair were designed in accordance with this data. Later, two slant observation wells were drilled and logs done in the middle part of the horizontal well pair, revealing that this area of the reservoir was not as good as expected. In fact the heel portion of the producer was drilled too low and outside the reservoir.

Full lithological descriptions can be found in the geology reports of the producer and injector well. (Appendix 3/B/C1/D1/D2) Gamma ray logs can be found in Appendix 3/C1/C2.

##### *2.1.1.2 Observation and core wells*

Survey (trajectories, GR) are available in the Appendix 3/E1/2 and on the CD under Appendix 3-2 under LAS format files.
Cores were only done with vertical observation wells (B/11-33, 0/11-33, A/11-33, OB1C). Pictures are shown in Appendix 3/F.

**Table 1: Observation & core wells descriptions**

| Well name | UWI | Status | Drilling date |
|---|---|---|---|
| A/11-33 | A/11-33-95-12W4 | Core well | 1974 |
| B/11-33 | B/11-33-95-12W4 | Core well | 2000 |
| 0/11-33 | 0/11-33-95-12W4 | Observation well with casing but not equipped | 2003 |
| OB1AA or OB1P1H | 103/06-33-095-12W4 | Slant observation well | 2004 |
| OB1B or OB1P1M | 102/06-33-095-12W4 | Slant observation well | 2004 |
| OB1C or OB1P1T | 100/03-33-095-12W4 | Observation well | 2003 |

##### *2.1.1.3 Cross sections & maps*

Refer to Appendix 3E1/2.

#### 2.1.2 Laboratory studies

No additional laboratory studies for Phase 1 were completed in 2009.

#### 2.1.3 Simulations

The description of what has been done in geophysics and reservoir simulation (input data, methodology and main results) is available in Appendix 4. No additional data is available on this topic.

#### 2.1.4 Pressure, temperature and other applicable reservoir data

Updated 2009 pressure data for the injector and the producer updated and historical temperatures profiles can be found in Figure 3.

#### 2.1.5 Any other measurements, observations, test or data pertinent to the pilot

Raw well data (Injector, producer and observation wells) data and production data with trends are available in Appendix 5. BHP is maintained in a range from 600kPa to 1200kPa, with a slightly higher pressure for the injector. BHP never reached the maximum allowable pressure of 1200 kpa that was defined after the steam release on Phase 2 well 204-P1.

### *2.2 Interpretation of Pilot Data*

This pilot has allowed gathering of information in SAGD technology. Geologically, the formation has been well described. Unfortunately, both slant observation wells were drilled after the horizontal well pair and showed worse quality than expected.

- Sensa fibre allowed operations to monitor temperature changes, issues identified early and acted on immediately.

# 3 Well Information

## *3.1 Review completion operations and any difficulties encountered in 2009*

The pump rotor was removed from the production well and both injector and producer were suspended in July 2009.

## *3.2 Well operation*

### 3.2.1 Well list and status

**Table 2: Well list and status - distance of observation wells from 1P1 & 1I1**

| Well name | UWI | Status | Distance from 1I1 (m) | Distance from 1P1 (m) |
|---|---|---|---|---|
| Phase 1 P1 (1P1) | 102/03-33-095-12W4/00 | Producer | - | - |
| Phase 1 I1 (1I1) | 103/03-33-095-12W4/00 | Injector | - | - |
| OB1AA or OB1P1H | 103/06-33-095-12W4 | Observation wells | 3.60 | 3.07 |
| OB1B or OB1P1M | 102/06-33-095-12W4 | | 6.05 | 5.40 |
| OB1C or OB1P1T | 100/03-33-095-12W4 | | 0.45 | 0.69 |
| 0/11-33 | 0/11-33-95-12W4 | Observation well with casing but not equipped | - | - |
| B/11-33 | B/11-33-95-12W4 | Core wells | - | - |
| A/11-33 | A/11-33-95-12W4 | | | |
| PW 10214-20 | 102/14-20-095-12W4M | Produced water disposal wells (No longer utilized in Phase 2) | - | - |
| PW 102-14-36 | 102/14-36-095-12W4M | | | |
| PW 11-36 | 100/11-36-095-12W4M | | | |
| PW 14-20 | 100/14-20-095-12W4M | | | |
| PW-14-36 | 100/14-36-095-12W4M | | | |
| PW 3-29 | 100/03-29-095-12W4M | | | |
| PW 5-4 | 100/05-04-096-11W4M | | | |
| BD 15-12 | 100/15-12-095-13W4M | Blow-down disposal wells (No longer utilized in Phase 2) | - | - |
| BD 4-16 | 100/04-16-095-12W4M | | | |
| BD 5-16 | 100/05-16-095-12W4M | | | |
| BD 7-13 | 100/07-13-095-12W4M | | | |

### 3.2.2 Wellbore schematics

Refer to Appendix 2 - Completion & work-over for all producer and injector wellbore schematics.

### 3.2.3 Spacing and Pattern

Not Applicable.

# 4 Production performance and data

## *4.1 Injection and production history on an individual well and composite basis*

The 2009 production was concluded on March 28$^{th}$., with the last day of production being March 27, 2009. The facility has since been suspended.

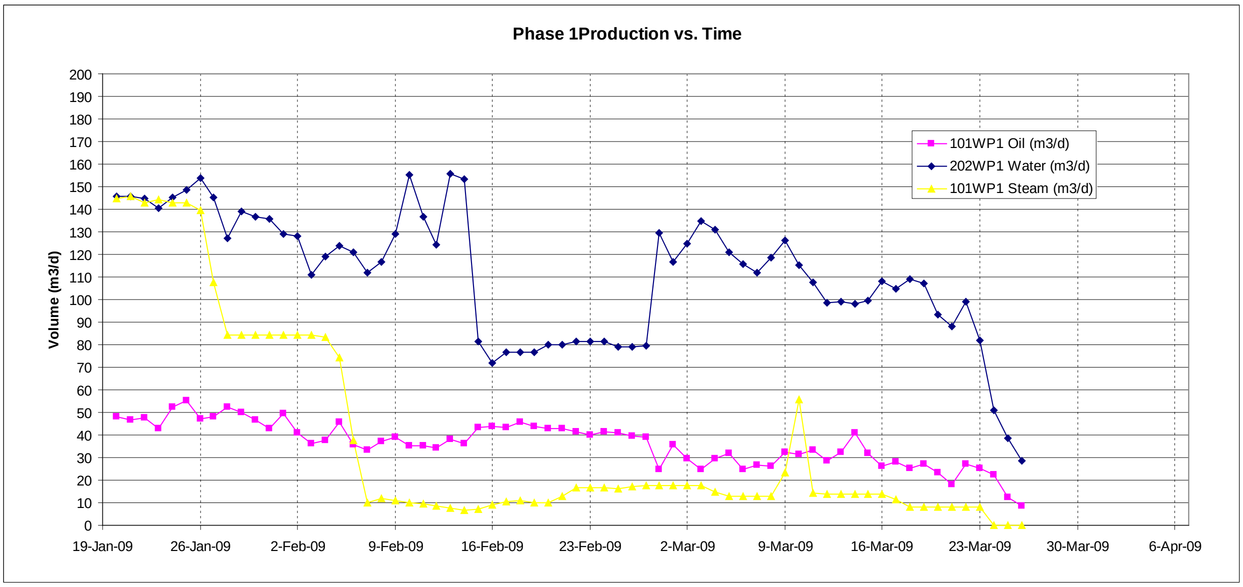


**FIGURE 1 : Actual Production 2009**

The 2009 production averaged roughly 39 m3/d of bitumen over the 3 months of production. This is illustrated in Figure 1 above. Total steam injection was stopped in February 2009. .

### *4.2 Composition of produced / injected fluids*

For oil/hydrocarbon analysis refer to Appendix 5B. Produced water was not analysed.

### *4.3 Comparison of predicted versus actual well / pilot performance and discussion regarding the difference*

This data is shown in Appendix 6/G. Because of the plugs mentioned previously, in both producer and injector wells in 2005, the actual production was not exactly matching forecasts and has been lower than expected. The ***modifications*** in late 2007 however, helped increase the production from the well to reach the forecasted values. Additionally, by changing the injection point of steam to the long string, the steam chamber quality improved.

### *4.4 History of injection, production and observation well pressures and temperatures*

Injector BHP was maintained at 1000-1200 kPa during both periods with rod pump and ESP. Producer BHP was always lower due to pressure drop between the injector and producer which was expected.

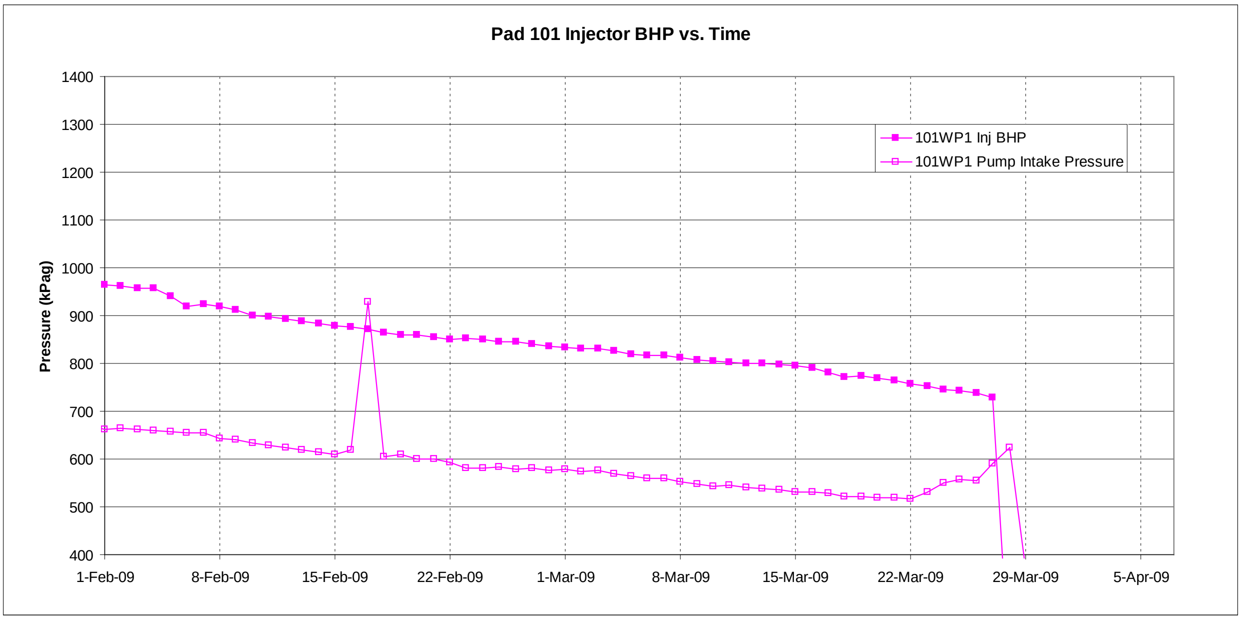


**FIGURE 2 : Pilot Pressures 2009**

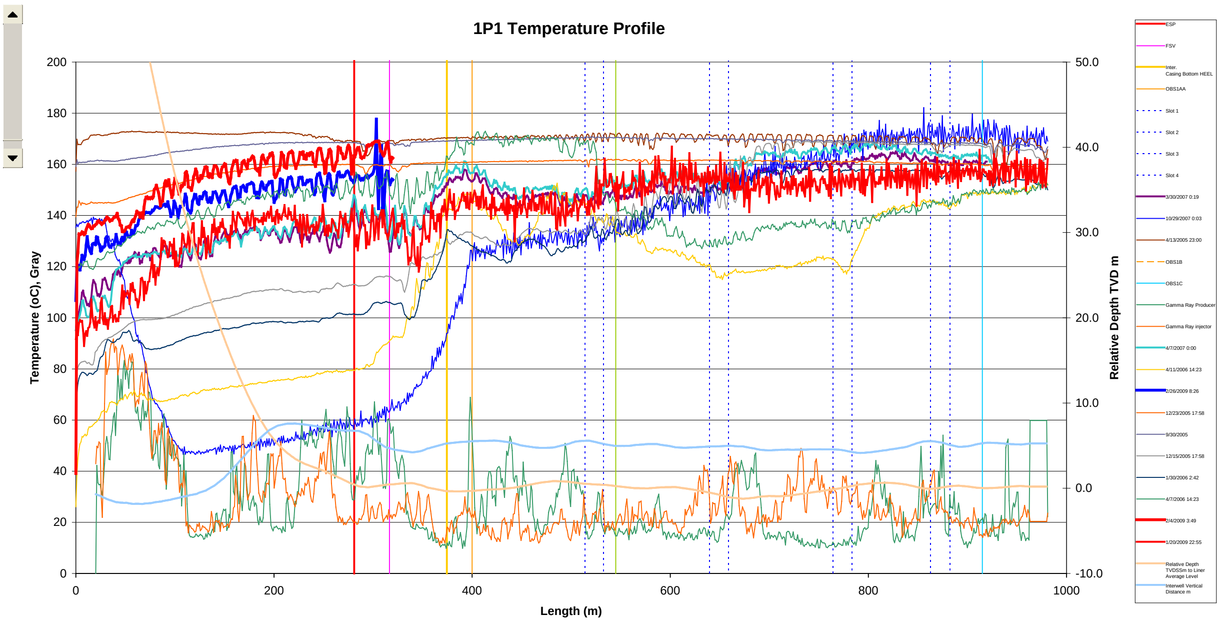


**FIGURE 3 : Pilot Temperature Profiles 2009**

# 5 Pilot economics to date *See Appendix 6

## *5.1 Sales volumes of natural gas and by-products*

No natural gas or by-products are sold.

## *5.2 Revenue*

Gross revenue for 2009 was $831,754.00.

## *5.3 Capital costs (include a listing of items with installed cost greater than 10,000$)*

- No capital expenditures. Project was suspended in March 2009.

### *5.4 Direct and indirect suspension costs by category (e.g. fuel, injectant costs, electricity)*

The post suspension costs for the Pilot have been calculated by prorating the costs between Pilot/Phase I and Phase II based on production volumes.

**Table 3: Direct & Indirect Suspension Costs 2009**

| | | |
|---|---|---|
| Direct Suspension Costs | *Trucking | 89,439 |
| | *Diluent | 689,620 |
| | On-site Labour | 883,296 |
| | Contract Services | 1,451,279 |
| | Utilities | 254,571 |
| | Supplies and Materials | 160,524 |
| | Property Tax | 92,448 |
| | Other | 90,623 |
| Indirect Suspension Costs | Off-site Labour | 1,165,514 |
| | **Total** | **4,877,314** |

***Note:** Steam generation and injection ceased in early 2009 however bitumen production continued until March.*

### *5.5 Crown royalties, applicable freehold royalties, and taxes*

Total royalties paid for 2009: $2,240 (Pilot fraction of total in 2009)

### *5.6 Cash flow*

No Cash flow was prepared as the project was to be suspended.

### *5.7 Cumulative project costs and net revenue*

Cumulative project cost: $7,147,275
Net revenue: $831,754(2009). Excluding royalty paid of $2,240

### *5.8 Explanation of material deviation from budget costs*

No operating budget was prepared for 2009 as project was to be suspended.

## 6 Facilities

### *6.1 Description of major capital items (including new facilities and additions / modifications to existing facilities)*

No capital expenditures in 2009.

### *6.2 Capacity limitation, operational issues, and equipment integrity*

The main issues and limitations that have been experienced are mainly due to pump issues. No major surface facility issues have been experienced. In a low pressure SAGD ESP's were difficult to maintain and require a lot of attention by both operations and engineering. Heat trace was introduced on the annulus line in order to prevent casing gas freeze off.

### *6.3 Process flow and site diagram identifying major facilities, including production equipment, connected pipelines, gathering and compressing facilities*

The Phase 1 wells are now tied in to Pad 204 and the Phase 2 facility. PFD/P&ID's of Pad 204 has been included in Appendix 7.

## 7 Environment / Regulatory / Compliance

### *7.1 Summary of project regulatory requirements and compliance status*

In March 2009, Total applied to the ERCB for the suspension of the operations. The suspension was granted in June 2009.

Total is in compliance with the AEPEA Approval No. 147283-00-00 to 03 and all the necessary regulations.

### *7.2 Procedures to address environmental and safety issues*

Corporate and affiliate HSE procedures are being followed and are in compliance with Municipal, Provincial and Federal regulations.

### *7.3 Plan for shut-down and environment clean up*

Pilot/Phase 1 plant was decommissioned in 2007, the phase 1 well was tied into pad 204.

In 2009 pipelines coming out from the wells at phase 1 and pad 204 were disconnected, steamed, drained and blanketed with Nitrogen.

A Soil Monitoring Program Proposal was sent to Alberta Environment in November 2009 and was approved, this monitoring proposal meet the requirements outlined in the Soil Monitoring Directive (AENV 2009a).

## 8 Future operating plan

### *8.1 Project scheduling update including deliverables and milestones*

The Joslyn SAGD Pilot has been suspended.

### *8.2 Salvage update*

Phase 2 equipment will be dismantled. Opportunities for salvage and reuse are being evaluated.

## 9 Interpretations and conclusions

***Lessons learned***

As more experience was gained with shallow SAGD operations the following optimizations were implemented.

- When the well showed signs of production decline, various techniques were utilized with success. A key example is the pump configuration change from an ESP to a PCP.
- Found that ESP's were not the ideal pumps for this type of shallow SAGD production. Plan to use a high temperature Progressing Cavity Pump (PCP) has proven successful. A PCP allows us to closely monitor the subcool, thereby improving the overall performance of the well.
- Steam chamber expertise has continued to increase and with this, well production improves.
- The reservoir behaviour is slow reacting, and production can be optimized with the right fix. Production had decreased to almost 15 cubes, and the well has since proven to be one of the best producers in the Joslyn SAGD field.
- Using metal on metal PCP systems SAGD production is possible with reservoir pressure down to ~800 kPa.

### *9.1 Difficulties encountered*

Refer to 6.2 for operational issues.

### *9.2 Technical and economic viability*

From a technical point of view, this pilot was successful and demonstrated that shallow SAGD could be produced. A PCP pump had been installed in 2007 and further research was done to increase pump efficiency and runtime.

### *9.3 Overall effect on overall gas and bitumen recovery*

Pilot oil is considered dead oil. Gas recovery is not applicable here.
An efficient oil recovery was successfully demonstrated.

### *9.4 Assessment of future expansion or commercial field application and discussion of reasons*

The pilot facility is called Phase 1 within the Company. Because of the pilot project success, the commercial Phase 2 was built in 2005/2006. In February 2006, the pilot well pair was connected to the commercial facility, phase 2 together with 4 other wellpads. The pilot facility was dismantled in 2007. Phase 2 is equipped with 17 well pairs and initially designed to reach 10,000 bbl/day. In 2009 the Joslyn SAGD project was suspended and application to dismantle the facilities are being approved by the ERCB and AB Environment.

# 10 **APPENDIX**

## LIST OF APPENDIX(S) AS SUBMITTED IN the 2008 IEPT Report

Appendix 1: Drilling operations
- Appendix 1/A: Injector well
- Appendix 1/B: Producer well
- Appendix 1/C: Observation wells

Appendix 2: Completion operations
- Appendix 2/A1: ESP to PCP Workover Replacement
- Appendix 2/A2: New Completion Drawing

Appendix 3: Mud and Geological Reports
- *Appendix 3/A: Injector well*
- *Appendix 3/B: Producer well*
- *Appendix 3/C1: Injector well – Horizontal lithology strip log*
- *Appendix 3/C2: Producer well – Horizontal lithology strip log*
- *Appendix 3/D1: Injector well – Vertical lithology strip log*
- *Appendix 3/D2: Producer well – Vertical lithology strip log*
- *Appendix 3/E1: Injector well – Cross section through Facies model*
- *Appendix 3/E2: Producer well – Log cross section*
- *Appendix 3/F: Core pictures*

Appendix 4: Geophysics simulations

Appendix 5: Production data
- Appendix 5/A: Observation Well Temperatures
- Appendix 5/B: Oil analysis

Appendix 6: Economics data
- Appendix 6/A: Statement of operating income 2008 & Capital 2008

Appendix 7: Facilities
- Appendix 7/A: Process Flow Sheet
- Appendix 7/B1: P&ID: Phase 1
- Appendix 7/B2: P&ID: Pad 204
- Appendix 7/C: Facilities plot
- Appendix 7/D: Major Equipment Listing
- Appendix 7/E1: Process Description
- Appendix 7/E2: Pilot overall description