Optimization of Subcool in SAGD Bitumen Processes

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ABSTRACT

Uniform steam chamber growth (conformance) in a Steam Assisted Gravity Drainage (SAGD) process promotes enhanced bitumen recovery, economics and environmental benefits. Operators have implemented many strategies to improve such conformance through simultaneous injection in the inner tubing and annulus space with dual-tubing completions, to provide some degree of injection control at the heel and toe regions of the horizontal well pair. Such strategies do not, however, necessarily guarantee the desired uniformity and efficiencies sought. Recent work suggests that using Proportional-Integral-Derivative (PID) feedback to control steam injection can provide beneficial gains in steam chamber conformance, particularly in heterogeneous reservoirs. The feedback control is applied to each steam injection point in the horizontal well pair. Injection at these control points is regulated by a PID feedback controller monitoring temperature differences between injected and produced fluids in order to both enforce a specified subcool and to achieve uniform production along the entire length of the producer. While it is beneficial to achieve a subcool so that steam utilization, or SOR, is improved, it may transpire that such metrics do not furnish the best (optimal) overall economics of the asset (i.e., Net Present Value, NPV).

This paper examines detailed wellbore simulations of a SAGD well pair with both dual tubing string and ICD completions in the producer and PID controlled steam injection with dual tubing strings. Two synthetic reservoir models, one based on an idealized heterogeneity pattern and the other based on logs from the Athabasca region of Alberta, are utilized, representing a highly heterogeneous formation, and typical of many bitumen assets. These simulations are employed as part of an optimization process in order to determine the optimal PID controller parameters, and thereby optimizing project NPV.

INTRODUCTION

Steam Assisted Gravity Drainage (Butler 1998 & 1991) is the most extensively used process for the development of bitumen resources in Western Canada. Figure 1 illustrates the process in which two closely spaced and adjacent (in a vertical plane) horizontal wells are used to inject steam from above, and, aided by gravity, drain the reservoir fluid towards the lower producer. The steam chamber itself constantly evolves, in time, as more steam is in-
An overview of a typical Steam Assisted Gravity Drainage (SAGD) process. Left-hand image: The location of the well pair, relative to surface facilities are shown along with an idealized, uniform, steam chamber (in red). Right-hand image: A cross-section view of an idealized, evolving, steam chamber. The heated oil–water mixture flows down the edge of the chamber to the oil producer.

Figure 2 presents an example of such a dual-tubing operation (as used by ConocoPhillips at Surmont, source: Energy Resources Conservation Board Alberta). There may be an additional coiled tubing instrument string with either a DTS distributed fiber-optic temperature measurement or thermocouple array included in the completion. Many of the reservoirs are low pressure and relatively shallow, e.g., Surmont (McMurray formation) has an initial pressure of ~25 Bar and a depth of 500 m.

The term 'subcool' itself refers to a prescribed (operational) temperature difference between fluids exiting the upper injector and entering the lower producer. This temperature difference is referred to as a 'subcool' since it forces temperatures near the producer to be several degrees below the water saturation temperature. Subcool may be controlled in several ways and is discussed by Edmunds (1998).

Prescribing the requisite injection and production rates for each tubing string may be determined from an analysis of the formation around the pair. However, such an analysis is often inexact for the following reasons.

If the steam chamber prematurely 'touches' the lower producer, it will result in significant inefficiencies since a fraction of the hot steam will flow directly into the lower producer instead of being more effectively utilized in growing the upper reaches of the steam chamber. However, the ability to set injection and production rates in order to reflect the current state of the reservoir, and current subcool at various points along the well pair, is difficult using conventional engineering analysis (conducted before, or during, the production cycle). To address this problem, it was proposed by Stone et al. (2011) to utilize a feedback controller to automatically monitor temperatures of both produced and injected fluids with a target subcool at both the heel and toe halves of the well pair. By targeting the same subcool at both ends, two objectives are accomplished: i) the subcool prevents steam from prematurely entering the lower producer, and ii) both toe and heel halves of the well pair are encouraged to produce uniformly since both are targeting the same subcool.

Another approach to improve conformance is to install Inflow Control Devices (ICDs) in either, or both, the SAGD injector and producer. If properly designed, the devices in the producer can:

i) Equalize the toe-to-heel influx of the emulsion,

ii) provide greater control of the subcool, and

iii) behave as autonomous, or self-regulating, valves.

This last objective is achieved if the liquid level is in close proximity to the device, resulting in flashing of the fluids within the ICD nozzle (since water and other fluids at the
control parameters include: with a liner and dual tubing strings, or with ICDs. These
trolled steam injection with a producer either completed
the key operating parameters associated with PID con-
Canada. Optimization parameters used in the studies are
ing two bitumen reservoirs in the Athabasca Tar Sands,
present two simulation-based optimization studies involv-
aforementioned advantages of these devices. We then
an overview of an ICD that is designed to deliver the
feedback control algorithm itself. This is followed by
reducing the operational complexity.
In this article, we first review the steam injection
feedback control algorithm itself. This is followed by
an overview of an ICD that is designed to deliver the
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trolled steam injection with a producer either completed
with a liner and dual tubing strings, or with ICDs. These
control parameters include:

i) Length of initial circulation or pre-heat period,
ii) Maximum allowed injection rate from each injection
tubing string,
iii) Water production rate limit either from each tubing
string, or from the heel if the producer is equipped
with ICDs,
iv) The proportionality constant, $K_p$, used in the PID con-
trollers.

By allowing sufficient operational ranges of these par-
parameters in a dedicated optimization using maximum Net
Present Value as the objective function, the following
questions can be examined:

i) Is there an economic advantage to using PID regula-
tion of steam injection in dual injection strings, or can the
same results be achieved with an equal and high
injection rate at both injection points?

ii) Is there a set of parameters that can achieve a more
sustained production over the life of the production
cycle?

Although NPV is used as the objective function, this work
does not intend NPV to be the basis of predictive eco-
nomics of the asset. Rather, it is used to determine the
optimal operating parameters for PID controlled steam in-
jection from dual tubing strings.

**PID CONTROLLER**

The Proportional-Integral-Derivative (PID) algorithm
(Åström & Hägglund, 1995) is the most commonly used
feedback controller in the industry. For our purpose, we
consider the following formulation:

$$Q_{inj} = (Q_{inj})_{start} + K_p \left[ e(t) + \int_{t_{start}}^{t} \frac{e(\tau)d\tau}{T_i} - T_d \frac{de(t)}{dt} \right], \quad(1)$$

where $Q_{inj}$ is the control variable, in this case the injection
rate at the short and long injection tubing strings in the up-
per injection well. $(Q_{inj})_{start}$ is the initial injection rate when
the controller algorithm is started, or reset, at a time $t_{start}$. Increasing the proportionality constant, $K_p$, may help the
process variable, in this case a temperature subcool be-
tween the upper injector and lower producer, to reach its
target more quickly. However, if this value is set too high,
oscillations of the process variables may result. Increasing
the integral time constant, $T_i$, helps to reduce the oscillatory
tendency of the process variables but will slow down the
rate at which they may reach their target values. A
dervative term, $T_d$, slows the rate of change of controller
output, including overshoot.

The error term, $e(t)$, in Eq.(1) is taken to be the differ-
ence between the subcool and a given target value. The
subcool is defined to be the injection well saturation tem-
perature, i.e., the temperature of steam inside the injec-
tion well, minus the temperature of fluids flowing into the
production well, namely:

$$e(t) = T_{sat} (P_{inj}) - (T_{inflow})_{prod} - T_{offset}. \quad(2)$$

When a controller, per Eq.(1), with an error term, per
Eq.(2), is used to control the injection rates of dual injec-
tion tubing strings (each of which is targeting a specified
subcool to the nearest region in the lower producer), both
objectives of meeting a subcool target and improving con-
formance are met. Steam chamber uniformity is improved
because each controller, operating on different regions of
the well pair, is attempting to achieve the same specified
subcool, i.e., the same $T_{offset}$.

Further details on how these PID equation formulations
are implemented in the numerical reservoir simulator, in-
cluding calculation of the subcool and additional filters, are
given in Stone et al. (2011).

**ICD DESIGN**

For this study, an ICD design was chosen to be similar
to that used in field operations described by Tran et al.
(2010) and Das et al. (2012). As described in Schlumberger
(2009), this device can operate under high temperatures
and combines a sand control screen with a choke that is
designed to deliver a linear production, or injection, profile throughout the length of the horizontal wellbore. These devices are installed in 7” base-pipe joints, each with a length of 46 feet. The screen OFA (Open Flow Area) per joint length is 7.8% for the injectors and 15.7% for the producers. Each joint is equipped with flow constriction nozzles. These nozzles have an effective throat diameter of 6.4 mm in the injectors and 4.2 mm in the producers. Flow across the nozzles produces a Bernoulli-type relationship (i.e., pressure drop versus flow rate), thus:

$$\Delta P_{\text{nozzle}} = C_u \frac{\rho_{\text{mix}} v_{\text{nozzle}}^2}{2 C_v^2}.$$  
(3)

In the wellbore model calculations within the reservoir simulator, this Bernoulli equation is calculated with in situ mixture densities and velocities. Figure 3 presents a schematic of the device and illustrates dimensions, outer screens, flow paths as well as a picture of the nozzle itself. It has been shown by Lauritzen & Martinussen (2011) that nozzles with this type of design allow Eq.(3), calculated with multiphase mixture velocities and densities, to be generally predictive with multiphase flow.

Pressure drop due to flow through the annulus is mainly due to friction, $\Delta P_{fr}$. In the simulations presented below, this is modeled with a slightly revised form of the Bernoulli equation, namely:

$$\Delta P_{fr} = 2 C_u f \left( \frac{\rho_{\text{mix}}}{\mu_{\text{mix}}} \right) L \frac{\rho_{\text{mix}} v_{\text{pipe}}^2}{D^2},$$  
(4)

where the friction factor, $f$, is a function of the mixture Reynolds number, $Re_{\text{mix}}$, calculated over both laminar to turbulent flow regimes, $\rho_{\text{mix}}$ is the mixture density and $v_{\text{pipe}}$ is the velocity of the fluid mixture in the pipe.

No attempt was made in this work to tune the devices to local rock parameters, such as permeability $k$, and porosity $\phi$, along the production well. Consequently, we do not claim that the stated nozzle configurations are optimal.

**WELL MODEL OVERVIEW**

A key component in any commercial reservoir simulator is the well model as it provides the source and sink terms that ultimately govern the progress of the simulation. Overall accuracy of the simulation is, therefore, dependent upon both the accuracy of the flow calculation in the reservoir grid and that of the wellbore model. As wells and their corresponding modeling requirements become more complex, the accuracy of the wellbore model may be a determining factor in the final acceptability of the simulation (Holmes et al., 2001; Stone et al., 2001).

Holmes et al. (2010) describe, in general terms, the multi-segmented well (MSW) model used in this work. It is part of a new scalable parallel commercial reservoir simulator presented by DeBaun et al. (2005) and Shi et al. (2009). The MSW model treats the well as a network of nodes and pipes as shown in Figure 4. A segment consists of a ‘node’ and a ‘pipe’ connecting it to the neighboring segment’s node towards the wellhead. Tubing strings may be added at any point within the MSW. More detail on the modeling of multiple tubing strings can be found in Stone et al. (2011).

**CASE STUDIES**

Two case studies are considered. The first, **Case Study #1** (discussed in Stone et al., 2011), was created from published studies concerning the Surmont field in Alberta, Canada (Handfield et al., 2009; Gates & Chakrabarty, 2006; Cokar & Graham, 2010). The second, **Case Study #2**, was
first presented in Stone et al. (2013a) with additional discussion in Stone et al. (2013b). It is a higher resolution simulation of an asset in the same region, based on publicly available logs (source: Energy Resources Conservation Board Alberta).

As many of the reported parameters as possible were accounted for including wellbore design, properties such as absolute and relative permeabilities and injection rates. These cases were designed to be fully representative of a thermal SAGD recovery operation of a bitumen asset, in order to optimize operating parameters of the thermal process in this work. An essential aspect for optimization is simulation robustness over a range of parameter configurations as generated by the optimizer.

Table 1 presents the reservoir properties used in this work with well design parameters shown in Table 2. Table 3 contains well operation rates and associated limits while Table 4 presents basic parameters used in the simulation models.

Surmont is a low pressure reservoir that is part of the McMurray formation in Eastern Alberta, Canada. Heterogeneity plays a significant role in steam chest development in the McMurray formation due to the higher permeability sand combined with a very high bitumen viscosity (Chen et al., 2007). Initial pressures can be as low as 23 Bar. One of the properties of the McMurray formation is the very high bitumen viscosity at initial conditions. Bitumen properties used in these studies are: (i) 9 °API, (ii) gas-free viscosity of 1.3×10^6 cP at 10 °C, (iii) initial (solution) GOR of 8 Sm^3/Sm^3.

In the second study, these were (i) 8 °API, (ii) gas-free viscosity of 1.6×10^6 cP at 10 °C, (iii) initial (solution) GOR of 15 Sm^3/Sm^3.

Case Study #1: Two 650 m long horizontal wells, with a 5 m vertical separation, were simulated. Net pay thickness is 22.5 m. Figure 5 shows a longitudinal cross-section of the three-dimensional grid. Reservoir heterogeneity is highly simplified and places permeability streaks with two 3 D (Darcy) vertical streaks at 1/5 and 3/5 along the length along the well, one 1 D vertical streak at 2/5, another of 2 D at 4/5 along the well. A 2 D streak in the horizontal plane is also present just above the injector. These high permeability streaks thus roughly divide the well region into five weak compartments.

Case Study #2: This study, based on publicly available logs, is deemed to be a highly heterogeneous bitumen reservoir and is depicted in Figure 6 which shows a 3-dimensional view of the grid, the property displayed being $k_x$ (permeability in the $x$-direction).

Further details on the distribution of porosity, initial water saturation and thermal conductivity can be found in Stone et al. (2013a & 2013b). This second study contains a single SAGD well pair, each well being 700 m long, with a vertical spacing of 5 m, dual tubing strings in the upper steam injection well, and the producer is completed with ICD’s along its entire horizontal length. The well pair is placed in the middle of the grid, the riser can be seen on the left of Figure 6.

In both case studies, the well pair was circulated with steam for a period of time, $t_{circ}$, then injection and production commenced for a period of 5 days without PID control, after which active PID regulation of the steam injection
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### Table 1 – Reservoir Properties for Case Studies

<table>
<thead>
<tr>
<th>Case</th>
<th>Depth (m)</th>
<th>Porosity (%)</th>
<th>Perm., k (Darcy)</th>
<th>Oil Sat’n, S_0 (%)</th>
<th>P_{init} (Bar)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>500</td>
<td>27</td>
<td>4 (3)</td>
<td>89</td>
<td>17</td>
</tr>
<tr>
<td>2</td>
<td>230</td>
<td>14–40</td>
<td>5.1 (hor.)</td>
<td>89</td>
<td>22</td>
</tr>
</tbody>
</table>

### Table 2 – Well Design

<table>
<thead>
<tr>
<th>ID</th>
<th>OD</th>
<th>Slotted Liner (m)</th>
<th>Compl’n Len. (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.076</td>
<td>0.089</td>
<td>0.219</td>
<td>0.241</td>
</tr>
<tr>
<td>0.150</td>
<td>0.216</td>
<td>0.219</td>
<td>0.241</td>
</tr>
</tbody>
</table>

### Table 3 – Well Operations

<table>
<thead>
<tr>
<th>Case</th>
<th>Maximum Water Injection Rate (Sm³/day) CWE</th>
<th>Max. Water Prod. Rate (Sm³/day)</th>
<th>Production THP (Bar)</th>
<th>Circulation Rate (Sm³/day)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>100–400</td>
<td>120–400</td>
<td>1</td>
<td>120</td>
</tr>
<tr>
<td>2</td>
<td>100–400</td>
<td>120–400</td>
<td>1</td>
<td>120</td>
</tr>
</tbody>
</table>

### Table 4 – Simulation Parameters

<table>
<thead>
<tr>
<th>Gridding</th>
<th>Time Simulated (years)</th>
<th>Max. Time Step Size (days)</th>
</tr>
</thead>
<tbody>
<tr>
<td>I×J×K (m×m×m)</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>20 × 20 × 15 (1.5 × 50 × 1.5)</td>
<td>8</td>
<td>10</td>
</tr>
<tr>
<td>201 × 15 × 44 (1.0 × 50 × 1.25)</td>
<td>6</td>
<td>10</td>
</tr>
</tbody>
</table>

rates in each injection tubing string began. The producer in the first case had the same number of tubing strings as the injector. Water production rate constraints on the production tubulars were set to be equal at switchover. In the second case, this producer was equipped with ICDs, and the well was operated with a single water production rate constraint set at the heel.

**OPTIMIZATION**

Multiple simulation runs were made within an optimizer, where the control parameters were chosen to be (i) length of initial circulation period, (ii) maximum steam injection rate allowed in each injection tubular, (iii) maximum water production rate allowed in the production tubulars or at the heel of the ICD-equipped producer, (iv) proportionality constant, \( K_p \), used in the PID controller, per Eq.(1).

The optimization scheme used in this work employs an adaptive Radial Basis Function (RBF) scheme. This was selected due to its ability for rapid convergence to an optimum and its proven robustness (Rashid et al., 2013). Rapid convergence is important for practical considerations when the objective function involves a computationally expensive simulator. Solution robustness was also deemed critical for the reasons stated earlier. Alternative optimization schemes are, of course, possible. These could include downhill simplex, neural network, evolutionary algorithms and others (a combination of direct and proxy solvers). However, based on previous work (Rashid et al., 2012 & 2013), these schema are known to require a greater number of trials and often result in poorer performance hence our justification on using RBF.

**SEGMENTATION AND MODEL ACCURACY**

In the first study, where both wells contained dual tubing strings, the wells were modeled with inner (long) tubing, an outer annulus and with boundary segments for fluid and energy flow. A boundary segment, i.e., a special segment with the ability to apply an external pressure or rate constraint, was defined at the heel of the annulus of both wells in order to model a short tubing string where fluids were removed or injected at a specified rate. Case Study #1, therefore, involved the model of a dual tubing configuration with flow through conduits comprising: a long tubing string, a short tubing string, along the annulus and also through a slotted liner to the reservoir.

Figure 7: Case Study #1: Dual Tubing String Wells. Segmentation, measured depths, grid dimensions and J-indexes in the \( y \)-direction.

<table>
<thead>
<tr>
<th>Grid</th>
<th>Time Simulated (years)</th>
<th>Max. Time Step Size (days)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.5 × 50 × 1.5</td>
<td>8</td>
<td>10</td>
</tr>
<tr>
<td>1.0 × 50 × 1.25</td>
<td>6</td>
<td>10</td>
</tr>
</tbody>
</table>
the wellbore model calculation possessed six variables, losses from the inner tubing strings to the annulus. Conductive heat transfer along the axis was modeled as were conducive as described in Eqs.(3 & 4).

In the injection well, steam is injected in either the short or long tubing string. Steam entering the annulus from either string is free to travel along the annulus and across the slotted liner into the reservoir at any point. The location where this occurs depends on the pressure profile in the annulus, the pressure drop from the annulus to the reservoir, and voidage mobility (or injectivity) of reservoir fluids. Generally, a steam volume fraction in the annulus is >99%, hence there is almost no condensate by volume. The large frictional pressure drop over the long tubular is resolved using multi-segmented (nodal) analysis with a homogeneous two-phase (steam/condensate) calculation for friction loss. Similarly, in the outer annulus (which comprises ~80% of the total cross-sectional flow area), condensate, and any produced fluid (during circulation), is <4% by volume. These liquids lie on the bottom of the conduit, the assumption of homogeneity in the pressure loss calculation in this part of the injector is not impacted, and the calculation is deemed to be sufficiently accurate for our purposes.

Pressure loss in the lower producer, as calculated with a similar homogeneous friction loss model, can be considered to be accurate since fluids will have a high liquid fraction due to the subcool control and are, in general, well mixed because the in situ flow regime is almost always turbulent (Re_{mix} > 2100). Figure 9 presents Re_{mix} generated from one of the cases simulated in this work, at various times after switchover in the outer annulus and in the long tubing string of the production well. As expected, the multiphase flow has a smaller Reynolds number in the annulus due to the larger flow volumes, especially near the zero point where the inflow splits before moving towards either the short or long tubing inlets. Also seen in Figure 9, at early times after switchover (t_{circ}), flow in the annulus is laminar (Re_{mix} < 2100), but quickly becomes turbulent after a month has elapsed, due to the increase in production. The mixture Reynolds numbers are much higher in the long tubing string (smaller cross-sectional flow area, thus higher in situ velocities) and are always turbulent. Turbulent multiphase flow, with a high liquid fraction due to the subcool control, and small amounts of entrained gas (methane), generally implies that the phases are well mixed and behave as a homogeneous mixture with minimal phase slippage. The homogeneous pressure drop cal-

**Figure 8:** Case Study #2: MSW Segmentation of the ICD-equipped production well. Shown are: segment node number, branch number, measured depth (m). Three segments are used to model each ICD nozzle (shown as a single segment here). This was necessary in order to improve resolution of steam flashing in the nozzle.

The first case is symmetric along the axis of the wells. To simulate half of a multi-segmented well (MSW), we have used half the cross-sectional flow areas for the tubing/annulus and the full hydraulic diameters for each. The retention of the original diameters was necessary in order to correctly calculate the mixture Reynolds number in the segment frictional pressure drop calculation, while the flow areas and volumes were halved to account for the symmetry. Annular hydraulic diameters accounted for the presence of tubing strings while heat transfer coefficients were halved as were injection rates. The size of the first grid cell in the lateral direction orthogonal to the vertical plane containing the wells and well productivity indices were also halved to account for the symmetry.

Conductive heat transfer from the wellbore to the formation was modeled using an overall heat transfer coefficient derived from a calculation suggested by Prats (1986) and was based on thermal losses from a steam injection well. Additionally, conductive heat transfer along the axis of the tubing strings was modeled as were conductive losses from the inner tubing strings to the annulus.

In all simulations undertaken here, all segments in the wellbore model calculation possessed six variables, namely: pressure, global mole fractions of heavy and light (methane) oil components, global mole fraction of water, total molar rate and total enthalpy. Reservoir and wells are fully coupled. The pressure drop calculation assumes homogeneous flow of the mixture in all circumstances, no separation of fluid phases and includes both form and/or friction components as described in Eqs.(3 & 4).
Figure 9: Case Study #1: Mixture Reynolds Numbers, \( R_{\text{mix}} \) against measured depth (m) in the production well. The upper plot shows \( R_{\text{mix}} \) for the Long Tubing String. The lower plot shows \( R_{\text{mix}} \) for the Outer Annulus, both at various times (days). Flow is deemed turbulent if \( R_{\text{mix}} > 2100 \). The zero point, or point where production splits and flows towards either tubing string can be seen in the upper plot.

ECONOMIC MODEL AND PARAMETERS

The primary objective function in this work is Net Present Value (NPV), which demands some form of economic model to be applied. Calculation of NPV includes: revenue from oil production, oil/gas/water processing costs, steam generation and injection costs, fixed daily costs, possible cost drifts, a basic tax and royalty scheme, capital expenditures at inception, with all future cash flows being discounted continuously, not discretely.

Bitumen assets are, generally, more economically marginal than those with a lighter oil. Upgrading costs can be significant if the bitumen is upgraded to a blend such as Western Canada Select, or to be made transportable via pipeline. The spot price of a standard barrel (STB) of field-produced bitumen can be 40% less than that paid for West Texas Intermediate (depending on the quality and API gravity). For the cases discussed here in this work, all economic parameters were chosen to be as accurate as possible. However, it became apparent while doing this study that certain location-specific cost reductions, available to thermal operators, can have a significant impact on NPV and thus on the overall economic viability of a project. Such details are beyond the scope of this work and are best handled using specialist tax and economic software. As such, the NPV computed as our objective function represents a reasonable ‘engineering estimate’ of the economics of an asset, but should not be considered definitive. Nevertheless, what is essential for our work is that NPV itself (our objective function) is responsive to changes in the control parameters (defined earlier). This criterion was well served by our NPV model which, as will be shown later, was found to be responsive to changes in these parameters.

Economic parameters used were as follows:

- At the time of writing, the spot price of a STB of produced bitumen was in the range of $65–70 for an “API 12 bitumen. Since the stock used in this work has a lower API gravity, we have estimated a price for gross revenue to be $55/STB, which may be conservative.
- Oil processing costs, based on those quoted in Ruiz et al. (2009) were set at $11/STB (oil). These costs include separation, transportation, minimal upgrading (possible addition of a diluent) and emulsion treatment.
- Water disposal cost was set at $2/STB (water).
- Steam injection costs were set to $4/STB (water), again using values stated in Ruiz et al., (2009), which include water treatment, the gas required to heat the water and operational boiler expenses.
- Fixed daily costs include electricity to operate the ESP lifting pumps, scheduled workovers and other miscellaneous items: this was set to $384/day.
- Initial capital expenditure (CapEx) was based on installation and materials for a steam injector with dual tubing strings, and a producer with dual strings or equipped with ICD’s (Schlumberger 2014).
- Other parameters were: discount rate of 10%, royalty (on gross) of 12%, tax (on net) at 33% and a cost drift of 3% per annum (upwards).

These numbers are not refined enough to provide a reliable prediction of break-even and profit, only the deployment of specialist economics software can furnish that. However, they are considered representative and responsive enough to assess our engineering operating parameters for optimal operation of the PID controllers, which is the focus of this paper.
The range of these operating parameters available to the optimizer was sufficient enough to allow the NPV to vary from negative to positive values, *i.e.*, the project never reached break-even, to a respectable return on investment.

**RESULTS: CASE STUDY #1**

Figure 10 plots NPV versus optimizer iterations for Case Study #1, sorted accordingly to NPV from least to greatest. This sorting of optimization trials (iterations) allows trends in control parameters to be better visualized. Note that the NPV's associated with the four worst-performing NPV's are not shown in order to scale the y–axis to make the plot more readable (allows greater vertical scale resolution). These very poorly performing, negative values for NPV, were the result of recovery operations which were extremely uneconomic.

In Figure 10, there exist, roughly four "regions" of similarly-performing NPV's, representative sorted trial indices for these are labeled accordingly. First is a group labeled 'Poor' with a representative sorted trial being 14. All NPV's from sorted trial index 14 downwards are negative and represent control parameters that have led to a production cycle that does not break-even at all. The second NPV range identified lies from sorted trial index 15 to 21, and is labeled as 'Better' (we represent this group with point 16 in Figure 10). The next NPV range identified lies from sorted trial index 22 to 78, is characterized as 'Good', but still not optimum (we represent this group with point 68). The fourth, and final, NPV range identified lies from sorted trial index 79 to 82. This set represents our 'Best' values of NPV and we represent this group with the last, *and optimum*, point 82 in Figure 10. The following figures show the corresponding four control variables plotted using the same sorted trial index ordering presented in Figure 10. This way of visualizing results better enables one to judge the relationship between the stated control parameter to their corresponding NPV value. Figure 11(a)–(d) presents results for the four control parameters, displayed using the same sorted trial index as Figure 10. Figure 11(a) shows circulation time, $t_{\text{circ}}$; Figure 11(b) shows the maximum Steam Injection Rate, $Q_{\text{inj}}$ (Sm$^3$/day) in the tubular; Figure 11(c) shows water production rate, $Q_{\text{wat}}$ (Sm$^3$/day) while Figure 11(d) presents values of $K_p$, the PID proportionality constant.

We now consider a comparison of these parameters with those used in the original study by Stone et al., (2011) which did not use NPV as an objective function, but rather focused on recovery. First, circulation time, $t_{\text{circ}}$, was originally taken to be 60 days, but the value that is associated with the best NPVs in Figure 11(a) is, generally, about 72 days. This suggests that a little more pre-heat is beneficial, but more than this is not warranted from an economic standpoint. Maximum steam injection rate for each tubular was originally set to 70 Sm$^3$/day cold water equivalent (CWE $= 2 \times 35$ Sm$^3$/day due to grid symmetry). Figure 11(b), however, suggests that a higher rate can be used, with a range of 100–150 Sm$^3$/day CWE. Similarly, a water production rate limit assigned to each production tubing string was originally set a little above 70 Sm$^3$/day but Figure 11(c) suggests that, in keeping with the steam injection rates, these values can be raised to a range of 120–170 Sm$^3$/day. Finally, the proportionality constant, $K_p$, used in Stone et al. (2011) was set at $K_p = 10$, but the figures in Figure 11(d) clearly demonstrate that a higher value would be preferred for $20 \leq K_p \leq 30$.

Next, control parameters for each of the four representative NPV 'regions' in Figure 10 is examined in more detail. The four sorted illustrative 'groups' are represented by the following indices:

a) 'Best': Represented by sorted trial index 82. This is the best value found, with a post-tax NPV of $2.45 \times 10^6$.

b) 'Good': Represented by sorted trial index 68, with a post-tax NPV of $1.78 \times 10^6$.

c) 'Better': Represented by sorted trial index 16, with a post-tax NPV of $1.19 \times 10^6$.

d) 'Poor': Represented by sorted trial index 14, with a post-tax NPV of $-1.0 \times 10^6$. 

**Figure 10:** Case Study #1: NPV (post tax) shown sorted in increasing order from the smallest to largest NPV. Each marker on the NPV curve is a single trial involving a complete simulation. Four representative simulation runs are noted representing: 'Poor': trial 14; 'Better': trial 16; 'Good': trial 68 and 'Best': trial 82.
The results for three financial metrics are shown in Figures 12(a)–(c).

Table 5 shows cumulative oil produced, water produced and water injected for the four simulations of the SAGD production cycles that represent these regions.

Revenues for all four groupings were similar, with 'Best' performing a little better than the other three. Table 5 presents cumulative oil produced, FOPT, which shows that 'Poor', 'Better' and 'Good' groupings were approximately equivalent at the end of the production period. Note that 'Good' revenues were slightly better in the middle of the period, but tapered-off towards the end. Operating expenditures (OpEx) for 'Best' and 'Good' were also almost identical, somewhat higher for 'Better' but much higher for the 'Poor' NPV case. This latter observation was due to high cumulative water produced and injected steam, as seen in Table 5. The 'Best' NPV group injected a little less steam.
Table 5 – Cumulatives for the four representative NPV ‘regions’

<table>
<thead>
<tr>
<th></th>
<th>'Poor' Index 14</th>
<th>'Better' Index 16</th>
<th>'Good' Index 68</th>
<th>'Best' Index 82</th>
</tr>
</thead>
<tbody>
<tr>
<td>FOPT: Oil, Sm³</td>
<td>18,852</td>
<td>18,818</td>
<td>19,013</td>
<td>20,537</td>
</tr>
<tr>
<td>FWPT: Water, Sm³</td>
<td>73,272</td>
<td>49,868</td>
<td>41,515</td>
<td>39,494</td>
</tr>
<tr>
<td>FWIT: Steam, Sm³</td>
<td>77,797</td>
<td>54,196</td>
<td>44,739</td>
<td>43,569</td>
</tr>
</tbody>
</table>

Note: Steam injection total (FWIT) is stated in CWE. FWPT is total water produced while FOPT is total oil produced (all stated in Sm³).

and produced a little less water than the ‘Good’ group did.

An examination of the behavior of the PID controllers in the four scenarios can partly explain these differences. Figures 13(a)–(d) show steam injection rates (in Sm³/day) at both heel and toe tubing strings for four NPV ‘groups’ stated.

Optimization parameters for the ‘Poor’ case involved a circulation period of 82 days, a maximum tubular injection rate of 50 Sm³/day, a tubular water production rate of 60 Sm³/day and $K_P = 8$. Figure 13(a) shows that the heel was injecting at the maximum allowed rate for the entire period, but production temperatures in the heel half were persistently cooler than observed at the toe. Steam was exiting the upper well at the heel and being produced at the toe. Water production rates were significantly above injection rates which, in turn, led to flow paths being established from the heel of the injection well to the toe of the producer. Finally the proportionality constant, $K_P$, was low compared to the ‘Best’ values seen in Figure 11(d) which were in the range $20 \leq K_P \leq 30$.

A more responsive PID controller is noted in the ‘Better’ group as shown in Figure 13(b). Optimization parameters for this case were 79 days for the circulation time, 107 Sm³/day maximum injection tubular rate, a water production rate limit at each production string of 118 Sm³/day and $K_P = 6$. The toe injection tubing string was only briefly injecting immediately after switchover. It then remained shut for the remainder of the production cycle, indicating that the toe of the production well was a little too hot, i.e., that steam was preferentially flowing towards the toe. The heel subcool was controlled very closely with a continuous adjustment of steam injection rates from the heel injection tubular. This resulted in much less steam being injected and produced than in the ‘Poor’ group scenario shown earlier; this can also be noted in Table 5.

The PID controller behaved very differently for the ‘Good’ NPV grouping. Control parameters for this case were 60 days for the circulation time, a maximum tubular injection rate of 200 Sm³/day, a tubular water production rate of 200 Sm³/day and $K_P = 50$. Note in Figure 13: Case Study #1 Results: Heel/Toe Steam Injection Rates in CWE in Sm³/day, for the four NPV ‘groups’ identified in Figure 10.
ure 13(c) that the injection strings never achieved maximum allowed rates, but this maximum allowed them to often reach values of greater than 80 Sm$^3$/day. Also to be noted in Figure 13(c) are $i$) the heel PID controller is constantly adjusting the injection rate in bursts of steam injection throughout the production cycle, these bursts are roughly periodic with a duration of about 60 days in the earlier stages of the production cycle and a little longer later on, $ii$) the toe controller is adjusting injection rates early after switchover but mostly stays shut with only minor adjustments during the remainder of the production period.

Examination of the heel and toe subcools (not shown) for this 'Good' NPV grouping reveals that both halves of the well pair were being maintained at subcools close to the target, i.e., the constant adjustments of the heel controller were also working to control, to some extent, the toe subcools. The proportionality constant for this case is higher than the 'Best' values seen, which were in the range $20 \leq K_p \leq 30$.

Regarding the 'Best' NPV group, the optimization variables for this case were 73 days for the circulation period, 105 Sm$^3$/day for the maximum steam injection rate at each string, 116 Sm$^3$/day for the water production rate limit at each tubular, and $K_p = 18$. Again the bursting steam injection is seen in Figure 13(d), but this time it is occurring in the toe injection tubulars, and with a slightly faster duration of about 50 days. As noted in the 'Good' case above, both the toe and heel regions of the well pair were close to achieving the target subcool, even though the heel controller was not working as hard as the toe controller. From Table 5, it can be seen that these parameters yielded slightly greater oil production and lower steam/water injected and produced.

RESULTS: CASE STUDY #2

Case Study #2 has ICD's in the production well. Figure 14 shows the post-tax NPV, with trials sorted (in the same manner as Figure 10). Figures 15(a)–(d) exhibit the corresponding results for the four control parameters. This case was running a much larger simulation model (in terms of number of grid cells). This meant that each simulation took much longer to run, with the result that it was not possible to obtain as many optimization iterations at the time of writing as were achieved for Case Study #1.

Despite having fewer optimization iterations, a comparison of trends in the control parameters between the two cases could be made and appear to be broadly similar. Circulation time is lower than that observed with Case Study #1, remaining at the minimum for the most favorable NPV values. However, it is believed that with more optimization iterations, this number would probably have increased. Maximum tubular steam injection rates appear to be settling at approximately 120 Sm$^3$/day, broadly in line with that found in Case Study #1 (100–150 Sm$^3$/day). Water production rate at each tubular is around the same limit found in Case Study #1. Finally, the proportionality constant has not settled but appears to be heading towards $K_p = 30$, close to the value found in Case Study #1.

DISCUSSION

Results from this study suggest that a PID controlled injection strategy for dual tubing strings has advantages over maintaining steam injection rates in these tubulars at a constant value. The controllers can quickly adjust these rates such that a subcool target is attained, thereby allowing efficient steam-oil recovery ratios. Additionally, in certain circumstances, these controllers may be able to improve steam chamber conformance along the entire length of the well pair, since the same subcool target is employed in both halves of the well pair. A major benefit of this technology is the ability to reduce the costs of steam injection and water production. A secondary benefit is that recovery factors may be improved. The 'Best' (optimum) production noted earlier consists of both of these benefits.

The control parameters chosen for this work are not complete, but are considered to be the most important in their impact on the objective function NPV. Further work needs to be made to establish if additional control parameters will have as much impact on the objective function as these. Such additional control parameters could include the integral time constant in Eq.(1) and the subcool target. Also, the same set of parameters could be applied at different time periods, for example, one set applied during the first year or two after switchover, then a second set...
Optimization of Subcool in SAGD Bitumen Processes

Figure 15: Case Study #2 Results. All plots have identical x–axes: simulation trials sorted by increasing NPV value. (a): circulation time, $t_{\text{circ}}$ (days), (b): maximum steam injection rate, $Q_{\text{inj}}$ (Sm$^3$/day) in the tubular, (c): water production rate limit, $Q_{\text{wat}}$ (Sm$^3$/day), (d): values of $K_p$.

If a detailed study was carried out of a particular field where more accurate economic parameters were known, then it would make sense to evaluate the applicability of introducing additional control parameters to the problem. It should also be appreciated that if the nature of the objective function were to change – for example with an economically rigorous post-tax RoI, then a different set of control parameters may be more appropriate. In other words, the impact of each of the aforementioned control parameters will possibly differ as the objective function metric changes.

The bursting and oscillatory nature of steam injection in the 'Good' and 'Best' cases was not seen in Stone et al. (2011) and is an unexpected result. This may be a more efficient method of steam injection than the continuous adjustment discussed in that reference and also seen in the 'Better' group case in this work. The reasons for this oscillatory steam injection are the higher maximum steam injection rates and proportionality constants used in this work than were employed in that reference. In response to a measured subcool that is higher than the target, the controller may set a higher steam rate and will do so more quickly due to the higher proportionality constant. This, in turn, will cause the subcool to decrease faster and overshoot, the controller will more quickly reduce the injection rate, and the cycle then repeats itself. In the original work, maximum steam rates and proportionality constants were estimated in order to keep the controllers adjusting the rates continuously and without oscillating. It would be interesting to investigate the impact of including the integral time constant, $T_i$, as an optimization control variable, on this oscillatory behavior.

The Case Study #1 'Good' NPV group permitted a higher maximum injection rate than the 'Best' one, but the economics associated with its recovery were not as good. Although actual injection rates did not reach the maximum, generally the 'Best' steam injection rates were significantly lower than those for the 'Good' scenario, as seen by comparing Figures 13(c) & (d). This suggests that if injection rates reach too high a rate at a particular time, less conformant flow paths can be established that are harder to break than if injection rates are maintained at a lower value. Lower rates allow the controllers to more easily respond to the half of the well pair in need of the greatest rate adjustments. The 'Best' group concentrated on the toe region while the 'Good' group was regulating the heel half of the well pair. Although increasing the proportionality constant can improve the gain of the subcool signal and hence lower the response time of the controller, the
response of the system is limited by many time scales, the most important of these being the time needed for fluids to flow from the outer regions of the steam chamber down to the production well.

If production rates are much greater than their corresponding injection rates, it is also easier for poor flow paths to become irretrievably established. For example, in the 'Poor' NPV group case, where production limits were significantly higher than injection rates, these paths became established at early times after switchover. Steam was exiting the heel of the injector, then flowing to the toe of the producer, and the low maximum rate combined with the low proportionality constant for that case were insufficient to allow the controller to break these paths. Once a flow path is firmly established, it is almost impossible for the PID controllers to break or mollify these paths.

CONCLUSIONS

The following conclusions are drawn from this work:

1. An optimization study was carried out to analyze operating parameters associated with a SAGD process in which injection rates from dual tubing strings were regulated with a PID controller. The controller target was the subcool in the heel and toe halves of the well pair. Producers were configured with either dual tubing strings or with ICDs.

2. The objective function considered was Net Present Value of a bitumen asset with economic parameters gathered from internal and published sources to furnish reasonable values, at the time of writing, for the case studies cited. NPV was very sensitive to water production and steam injection costs.

3. Results suggest that PID control of steam injection from dual tubing strings can achieve better recovery and asset economics than maintaining the steam injection at a constant rate.

4. Some of the most important operating parameters of this injection strategy were analyzed with the help of the optimizer, and practical improved ranges of these parameters were determined.

ACKNOWLEDGMENTS

Conversations with Farrukh Akram and Brian Martz of Schlumberger regarding the economic parameters used in this work are acknowledged and appreciated.

Nomenclature

- \( D \) Diameter (of conduit), m
- \( C_u \) Unit conversion coefficient used in Eqs.(3) & 4
- \( C_v \) Coefficient used in Eqs.(3) & 4
- \( e(t) \) Error term at time \( t \): the difference between the subcool and the stated target temperature, \( ^\circ C \)
- \( f \) Friction factor (given as a function of \( Re_{mix} \)), dimensionless
- \( k_x \) Permeability in the \( x \)-direction, Darcies
- \( K_p \) PID proportionality constant
- \( L \) Length (of conduit), m
- \( \Delta P_{nozzle} \) Pressure drop over constriction (nozzle), Bar
- \( \Delta P_{fr} \) Pressure drop due to friction, Bars
- \( P_{init} \) Initial pressure, Bars
- \( P_{inj} \) Injection pressure, Bars
- \( Q_{inj} \) Steam injection rate, \( \text{Sm}^3/\text{day} \) (CWE)
- \( Q_{inj}/t_{start} \) injection rate when the PID controller is started (or reset), \( \text{Sm}^3/\text{day} \)
- \( Q_{wat} \) Water production rate, \( \text{Sm}^3/\text{day} \)
- \( Re_{mix} \) Mixture Reynolds number, dimensionless
- \( T_d \) PID derivative term constant, \( ^\circ C \)
- \( T_i \) PID controller integral time constant, days
- \( T_{inflow} \) Temperature of fluid inflow, \( ^\circ C \)
- \( T_{offset} \) Specified subcool target temperature, \( ^\circ C \)
- \( T_{sat} \) Saturation temperature, \( ^\circ C \)
- \( t_{circ} \) Circulation time, days
- \( t_{start} \) Start of time, days
- \( t_{end} \) End time, days
- \( v_{nozzle} \) velocity of the mixture through the constriction (nozzle), m/s
- \( v_{pipe} \) velocity of fluid mixture through the conduit (pipe), m/s
- \( \phi \) Porosity, fraction
- \( \rho_{mix} \) Mixture density, kg/m\(^3\)

Acronyms

- BHP Bottom hole pressure, Bar
- CWE Cold Water Equivalent
- DTS Distributed [fiber-optic] temperature sensor
- FOPT Field Oil Production Total, Sm\(^3\)
- FWIT Field Water Injection Total, Sm\(^3\). This represents the CWE of steam injected
- FWPT Field Water Production Total, Sm\(^3\)
- GOR Gas–Oil Ratio, Sm\(^3\)/Sm\(^3\)
- ICD Inflow Control Device
- ID/OD Internal/Outer diameter (of conduit), m
- MSW Multi-Segmented Wellbore
- NPV Net Present Value, stated here in US\$\times10^6
- PID Proportional-Integral-Derivative
- RoI Return on Investment
References


