Evaluation of the Design of Liner Deployed Inflow/Outflow Control Devices for SAGD Wells

By

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A report submitted in partial fulfilment of the requirements for the MSc and/or the DIC

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DECLARATION OF OWN WORK

I declare that this thesis:

Evaluation of the Design of Liner Deployed Inflow/Outflow Control Devices for SAGD Wells,

is entirely my own work and that where any material could be construed as the work of others, it is fully cited and references, and/or with appropriate acknowledgment given.

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Abstract

Steam assisted gravity drainage (SAGD) is a proven extraction method for the in-situ recovery of bitumen for reservoirs in Canada. To be successful, SAGD projects require low steam–oil ratios and high production rates. These are achieved through controlled steam chamber growth, which is highly dependent on steam distribution along the wellbore and geological heterogeneity. Subcool control in the production well helps to maximize production rate and prevent steam breakthrough.

Inflow control devices (ICDs) are a proven technology for non-thermal well applications to minimize the effect of frictional pressure drop along the wellbore in horizontal wells, leading to high fluid outflux/ influx at the heel. Limited literature is available on the applications of ICDs for SAGD production techniques. Reservoir simulations, based on literature suggests that the application of ICDs to SAGD injectors can control outflux and influx along the wellbore, promoting steam chamber conformity. In the producer well ICDs can maintain a uniform liquid level above the well to prevent steam breakthrough. ICDs have successfully been implemented in SAGD operations by ConocoPhillips at their Surmont field.

In this work, uniformly sized liner-deployed ICDs are evaluated for SAGD injection and production wells, through coupled wellbore/reservoir simulations. To keep the results generic, “strength” is used to compare ICDs for the different simulation scenarios. The higher the strength, the higher the pressure drop across the device. This analysis serves as initial design to assess appropriate pressure drops across the devices, allowing for simple simulation and quick decisions. The thermal effects were neglected and only single phase injection/production was modeled.

A conventional SAGD injector and producer well pair was simulated for comparison to wells completed with liner deployed ICDs. Through simulations, strengths for corresponding heel to toe variations and necessary wellhead and bottom hole pressures were determined. ICDs help to minimize the effect of friction along the liner, effects of heterogeneity, allow for proportional steam placement control and longer horizontal lengths. Despite the difference in operations for SAGD, the results are similar to ‘conventional’ implementation of flow control devices, except that the injected ‘steam’ phase has a lower viscosity than water.
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Inflow control devices (ICDs) are a proven technology for non-thermal well applications to minimize the effect of frictional pressure drop along the wellbore in horizontal wells, leading to high fluid outflux/influx at the heel. Limited literature is available on the applications of ICDs for SAGD production techniques. Reservoir simulations, based on literature suggests that the application of ICDs to SAGD injectors can control outflux and influx along the wellbore, promoting steam chamber conformity. In the producer well ICDs can maintain a uniform liquid level above the well to prevent steam breakthrough. ICDs have successfully been implemented in SAGD operations by ConocoPhillips at their Surmont field.

In this work, uniformly sized liner-deployed ICDs are evaluated for SAGD injection and production wells, through coupled wellbore/reservoir simulations. To keep the results generic, “strength” is used to compare ICDs for the different simulation scenarios. The higher the strength, the higher the pressure drop across the device. This analysis serves as initial design to assess appropriate pressure drops across the devices, allowing for simple simulation and quick decisions. The thermal effects were neglected and only single phase injection/production was modeled.

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Introduction
Steam-assisted gravity drainage (SAGD) is the main commercial in-situ thermal recovery method for hydrocarbons in heavy oil and bitumen reservoirs in Canada. These reservoirs are composed of unconsolidated sands. The oil is immobile at undisturbed reservoir conditions (typically between 7-11 °C) due to its high viscosity and lack of natural drive mechanism.

The viscosity ranges from 100,000 to 1,000,000 cP (Mehrotra and Svrcke, 1986) and when heated to above approximately 80°C becomes mobile. At 80°C the viscosity is between 600 and 1000 cP.

In the conventional SAGD process, two horizontal wells are drilled in the same vertical plane, with the injector 5-10 m above the producer (Butler, 1994; Damas et al., 2009; Edmunds and Gittins, 1993; Henriksen et al., 2006; Komery et al., 1999; Singhal et al., 1998). There is an 80 to 100 m spacing between well pairs, with 8-10 well pairs off each well pad (Butler, 1994; Edmunds and Gittins, 1993; Komery et al., 1999; Singhal et al., 1998). Steam is continuously injected into the injector well to heat the reservoir. This process is highly energy-intensive due to the natural gas and water necessary for steam generation (Deng et al., 2010). As a result, there is a strong motivation to increase recovery and reduce the cumulative steam-to-oil ratio (CSOR).

Controlled steam chamber growth in SAGD operations is important for achieving a larger steam-oil contact area and steam chamber conformance, both of which lead to higher production rates, increased recovery, and greater efficiency of the operation (reduced CSOR). Factors influencing steam chamber growth are reservoir properties, wellbore completion techniques and operating rates, pressures, and energetics of the steam (Gates et al., 2007; Shaw and Bedry, 2011; Wei and
Heat transfer losses and frictional losses can impair the efficiency of steam distribution along the wellbore. Steam conformance along the full length of the wellbore is critical for maximum recovery and is a key factor in process performance and uniform steam chamber growth. Proportional steam distribution helps to maximize economics, recovery and sweep efficiency (Edmunds and Gittins, 1993).

By imposing a pressure drop through a choke, advanced completions help to minimize the effect of friction along the tubing. This aids in creating a uniform/proportional flux along the wellbore to mitigate water or gas breakthrough for conventional production. There are two major types of advanced completions used for non-thermal horizontal wells: inflow control valves (ICV) (Gao et al., 2007) and inflow control devices (ICD) (Al-Khelaifi and Davies, 2007). An ICV has a variable inflow/outflow rate and pressure relationship; for ICDs, the relationship between pressure drop and rate is fixed. ICDs offer similar benefits to ICVs but have increased reliability due to their non-adjustable parts.

ICDs are a proven technology for non-thermal applications. For SAGD applications, the devices offer the potential benefit of proportional steam distribution along the wellbore and allow for longer wellbores. For the producer, a more uniform influx may help to maintain an adequate/uniform liquid level above the production well (steam trap control) to prevent steam breakthrough. This may lead to reducing the CSOR and increasing recovery. Due to the harsh operating environments and high cost, relative to SAGD well costs, ICD applications have been limited in SAGD wells. Inadequate literature is available on the field implementation of ICDs for SAGD applications and for steam injection, with the only shared experience being at the Surmont field consequently, the technology is considered unproven.

In 2012, ConocoPhillips described their success in obtaining uniform steam chamber growth at their Surmont field through the use of liner-deployed inflow control devices (ICDs) called an “Equalizer”, a helical flow channel device (Stalder, 2012). The injector has 7% of its length as open screen, while the producer has 36%. The liner-deployed restrictors were designed to generate a pressure drop of 340 kPa (50 psi) for 550 CWE m²/d of steam for 41 devices at 85% steam quality for the injector. For the producer, the ICDs were designed to give a 28 kPa (4 psi) pressure drop for an emulsion rate of 750 m³/d through 59 devices. Both wells have a 0.17 m base pipe and a horizontal length of 900 m.

ICDs can be deployed along the tubing, located within a slotted casing, or along the liner, with direct reservoir contact. The benefit of liner deployed devices over tubing deployed is that there is no flow in the annulus so the steam can be more controlled and directed into the reservoir, assuming isolation between the devices. For SAGD applications there are no suitable packers or isolation devices successfully applied. Due to the unconsolidated nature of the reservoir, it is assumed that there will be no flow in the liner/open hole annulus as the formation will collapse on the liner.

The SAGD process is carried out in four distinct phases: circulation, ramp-up, SAGD operation (steady state) and blowdown. In the circulation phase, steam is circulated in the injector and producer wells to establish hydraulic communication between the well pair. During ramp-up, steam is injected through the injector well to develop a steam chamber, lasting 6-18 months. In the operational phase, most of the oil is produced. The steam chamber extends laterally depending on reservoir quality, reservoir boundary and heterogeneity, lasting between 16-60 months. For this study, this is referred to as steady state. Blowdown is characterized by a decline in production rate due to the decreased drainage angle and heat loss to the overburden and cessation of injection.

**Objective**

The objective of this study is to simulate the implementation of liner deployed ICDs for SAGD injection and production wells at steady state for initial design to determine appropriate pressure drop necessary through the flow control device. Through coupled wellbore/reservoir simulation, the necessary pressure drop for uniform flow will be evaluated.

The analysis is for steady state operations, it is assumed that the area surrounding the well will be sufficiently heated to prevent any heat transfer and is therefore negligible. The liner deployed devices modeled will be of equal size to allow for generic design and to simplify the completion at site and save time by using a generic device. The purpose of ICDs for SAGD applications are to provide proportional outflux along the horizontal section for the injector well, despite variations in reservoir permeability. For the producer, level/chocked flow may help to provide uniform influx for subcool control. Scenarios for simulations of the injector include: comparison to a conventional SAGD well, heterogeneity along the wellbore, varying height reservoirs and longer wellbores. For the producer, a homogeneous case and heterogeneous case will be evaluated and compared against a conventional SAGD producer well.

**Background**

*Conventional SAGD Well Pair.*

In the SAGD process the injected steam creates an essentially constant-pressure steam chamber in the reservoir growing upwards and sideways as the oil is produced. As the steam condenses, it releases latent heat, heating the oil via thermal...
conduction (Edmunds and Gittins, 1993). This lowers the oil viscosity increasing mobility (Butler, 1994; Butler and Stephens, 1981). The mechanism is further described in Figure 1.

Conventional SAGD injector well design includes injection points at the toe and heel either in a parallel or concentric (tubing string inside of another) tubing configuration (Das, 2005b; Medina and Wat, 2012). The dual tubing strings are installed in a slotted liner with a 0.5-2% open area (Gotawala and Gates, 2009). For the injector, under typical operating conditions, ≥80% of the steam is injected at the heel tubing. Further discussion on the advantages and disadvantages of each well design can be found in work by Das (2005b). A SAGD producer well typically consists of a slotted wellbore, 0.18 m in diameter with a heel string and electrical submersible pump (ESP).

In SAGD, through gravity, the heated fluid is drained towards the production well. The liquid level above the producer acts as a sump/liquid inventory. The pressure drop induced by the ESP then moves the fluid to the wellhead. There is a potential of steam breakthrough occurring if the fluid removed from the well exceeds the rate of bitumen and condensed water (analogous to water breakthrough (Das 2005b)), or pressure below the steam saturation pressure. To prevent steam breakthrough a liquid level is maintained above the producer. This is monitored through the subcool, the difference between steam saturation temperature and produced fluid temperature. For high subcool there is a high liquid level above the producer, and a greater temperature difference; this can impair oil production. Low subcool, and a corresponding low liquid level may cause steam to bypass to the producer and damage the completion (Das, 2005a).

The major difference between conventional water injector horizontal wells and SAGD injectors is mobility, \( \lambda \), described by Equation 1, and volume rate (steam volume compared to water is much greater for the same weight). Due to the unconsolidated nature of SAGD reservoirs, the average permeability is \( \sim 5000 \) mD. Typical sandstone reservoir permeability is closer to \( \sim 250 \) mD (estimate). With a low injectant viscosity, and the high permeability of SAGD reservoirs, the mobility of steam is high (assuming only single phase flow).

\[
\text{Mobility} = \lambda = \frac{k}{\mu} \tag{1}
\]

The mobility and viscosity of 95% quality steam between 100 ºC and 300 ºC is compared to water at the same temperature and mobility in Figure 2. The mobility of water at 250 mD is also shown. The difference in mobility of steam at 230 ºC (Law et al., 2000) is \( \sim 6.5 \) times that of water for a 5000 mD reservoir and \( \sim 140 \) times that of water for a 250 mD reservoir (the higher the quality of steam, the higher the viscosity of the steam at the same temperature). Oil flow would have a lower mobility than water as it is typically a higher viscosity (not shown). The steam quality will also impact the mobility.

**Influence of Pressure Drop and ICDs**

Due to the frictional pressure difference occurring along the wellbore, and variations in permeability, non-uniform flux occurs with higher rates at the heel (Birchenko et al., 2010; Daneshy et al., 2010; Ouyang and Huang, 2005). The variation in pressure is known as the “toe to heel effect”, as depicted in Figure 3. It is dependent on the fluid mobility, the drawdown pressure and the roughness of the pipe, all influencing friction along the wellbore.

Figure 3: Skewed drawdown for a horizontal well in a homogeneous reservoir. (Addiego-Guevara et al., 2008).
The outflux of steam into the reservoir from the well, and production from the reservoir to/from the wellbore is described by Darcy’s law (or modified Darcy’s law (Butler, 1985)) and wellbore pressure loss. The flow is dependent on the viscosity, permeability variations, and pressure difference between the annulus and reservoir (assuming laminar flow). ICDs installed at regular intervals induce an additional pressure drop to directly control the steam, reducing the impact of wellbore pressure loss. The flow from the reservoir to the well is then a combination of Darcy and choke flow controlled by the flow regime in the wellbore, fluid density, pressure and permeability variations in the reservoirs.

Overview of Inflow Control Devices and Types

The first application of ICDs was at the Troll oil field. Henriksen et al. (2006) and Daneshy et al. (2010) reported that the additional pressure drop provided by the devices helped to delay gas breakthrough and increase oil production. The authors suggested that the logistical advantage of uniformly sized ICDs along the entire length is greater efficiency for implementation. Using tubing deployed devices, having different strengths of ICDs would make inflow control less efficient due to potential leakage in the openhole/liner annulus from the strong to weaker ICDs without effective isolation.

Since their first application, ICDs have successfully been installed as part of well completions to optimize reservoir performance. ICDs evenly distribute flow along the well, reduce early water or gas breakthrough at the heel, and delay water breakthrough at high permeability locations in heterogeneous formations (Al-Khelaiwi and Davies, 2007; Fernandes et al., 2009). There are three basic types of ICDs: channel-type ICDs, helical, orifice/nozzle-type ICDs, and combination hybrid ICDs. Despite the design differences, the basic principle of applying a pressure drop is the same. The principle is based on the Bernoulli equation, Equation 2. ICD types and their differences are further described in work by Al-Khelaiwi et al. (2007).

\[ \Delta P = \frac{1}{2} \rho u^2 \]  

ICD Applications to SAGD

Most of the available literature on the application of ICDs for SAGD reservoirs is of simulation results, with only one field application documented. Simulation results have demonstrated that ICDs for steam management help to provide controlled steam distribution, minimize the effects of reservoir heterogeneity and variable pay, and allow for longer wellbores. In addition, ICDs potentially may help to reduce the CSOR, aiding in preventing steam breakthrough, allow for simpler completions and operating strategy, extend the life of ESPs (less speed variability), and improve well performance and increase recovery. No previous work has looked at liner deployed devices.

Tachet et al. (2009) addressed the impact of friction and heat exchange on steam distribution through multi-segment simulation of SAGD wells completed with SteamSaver™ technology (tubing deployed flow control devices). The SteamSaver™ is a completion device composed of a nozzle and splitter sleeve that controls the flow of steam and aids in enhancing steam quality. Results suggested that frictional pressure drop has a strong influence causing uneven steam distribution in the reservoir. With even steam distribution along the wellbore, there is a greater potential for a more uniform steam chamber. The simulations considered four tubing deployed ICDs placed along the length of the injector well. Through the analysis of simulations including varying proportions of heterogeneity in the reservoir, the authors suggested that reservoirs with significant geological barriers did not necessarily benefit from this technology, as the length scale of the heterogeneity has a larger impact than wellbore distribution on the growth of the steam chamber. For this application the bottom hole pressure (BHP) was held constant, therefore, with higher strength ICDs, there was a lower steam pressure at the well-reservoir interface. Based on the properties of steam, this leads to a lower temperature, which, in turn, affects the produced fluid viscosity and therefore production rate. For this study, the injector wellhead pressure will be considered variable to counteract this problem. For this analysis only the near wellbore heterogeneity is considered, impacting inflow or outflow. Reservoir simulation is necessary to determine the overall effects of reservoir heterogeneity away from the wellbore.

Damas et al. (2009) compared completions with and without tubing deployed ICDs through thermal/compositional numerical simulation. The analysis considered different devices implemented to determine the effects of the completion for the reservoir. Results suggested that tubing deployed ICDs with cross-sectional areas of equal size along the completion display similar effects to slotted liners. The inflow imbalance is dominated by frictional losses and is insensitive to reservoir heterogeneity, suggesting that monotonically increasing the strength of the ICDs from the heel to the toe has the greatest impact on equalizing the pressure distribution. The study did not assess reservoir heterogeneity impacts through different reservoir models. For this analysis, the devices considered are liner deployed and it is assumed no annular flow will occur.

Perdomo et al. (2008) conducted a numerical study of operations in the Orinoco heavy oil belt, and evaluated the application of tubing deployed ICDs for SAGD wells through multi-segment wells. The study addressed the sensitivity of the steam injection rate, heat transfer, horizontal well length, selective steam placement and inter-well vertical spacing on the
SAGD process. The paper did not consider different ICD configurations and lengths; however, the authors suggested there is potential for longer horizontal wells through the use of ICDs and that an increase in oil recovery (8-17%) may be possible.

Reservoir heterogeneity, in most reservoirs, has a negative impact on SAGD as it affects steam distribution and temperature in the reservoir, thus affecting bitumen production rate. The length scale of geological barriers affects steam chamber growth. Based on simulations by Gotawala and Gates (2010), permeability distributions with correlation length scales equal to 135 m or greater, have the greatest influence on steam chamber shape. Reservoir simulation is necessary to evaluate the application of ICDs in reservoirs, and the length scale over which they may neutrally affect steam chamber growth.

The impact of “heat” losses to shale in the reservoir will have an impact on the heat distribution in the reservoir and thus viscosity and production rate of the produced fluid. The higher the shale-sand ratio the higher the CSOR to produce the same amount of oil as in a lower shale-sand ratio system due to the heat loss to the water filled interbedded shale (Boberg, 1966). This effect is not simulated as part of the steady-state analysis.

ICD Strength Relationship
To quantify the relationship between pressure drop and rate through the device, ICDs are typically sized based on strength, \( a_{\text{ICD}} \), or coefficient of drag, \( C_d \) (actual mass rate divided by the theoretical mass rate). For a channel ICD, the relationship is based on pressure (commonly expressed in bars) over flow rate squared. The rate can be inflow or outflow depending on the application. To keep the results generic for this report, strength, \( a_{\text{ICD}} \) (bar/(m^3/day)^2), is calculated using Equation 3 (Birchenko et al., 2010). Based on the relationship suggested, the higher the ICD strength, the higher the pressures drop across the device.

\[
a_{\text{ICD}} = \frac{\text{Average } \Delta p \text{(bar)}}{\text{Average } q^2} \times 1000 \quad (3)
\]

Sample strengths from the Troll field are found in Table 1 (Henriksen et al., 2006). The table refers to a pressure drop when a standard 12 m ICD is exposed to 26 Sm^3/d. To determine the appropriate ICD strength it is advised to use a flow resistance relationship curve provided by the distributor such as Baker Hughes or Schlumberger.

| Table 1 - Channel ICD strengths based on Troll Field (Henriksen et al., 2006) |
|------------------|--------|--------|-------|-------|-------|
| Industrial ‘bar’ rating | 0.2    | 0.4    | 0.8   | 1.6   | 3.2   |
| \( a_{\text{ICD, bar}} \) (Rm^3/day)^2 | 0.00028 | 0.00055 | 0.00095 | 0.0016 | 0.0032 |
| \( a_{\text{ICD, psi}} \) (Rbbl/day)^2 | 0.0076  | 0.0015  | 0.0026  | 0.0044 | 0.0087 |

Methodology
Modelling Approach – Injector and Producer
To evaluate the effectiveness of tubing-deployed ICDs, a conventional injector and producer SAGD well was modelled for comparison. Based on this analysis it is recommended to use the pressure drop across the ICD at the design rate to determine an appropriate ICD, and to further model the design in a reservoir simulator with the appropriate ICD relationship built in.

For the injection and production wells, the simulation setup is similar; however the simulation constraints are different. For the injector the rate was fixed and the wellhead pressure (WHP) variable. For the producer the bottom hole pressure (BHP) was fixed with a variable rate. Each well is modelled in isolation. All rates provided are in reservoir volumes.

For the injector, different strengths of ICDs (different pressure drops across the devices), calculated with Equation 3 were modeled for different wellbore radius to determine the most effective pressure drop for minimizing the “heel-toe” variation of flow along the well. Multiple simulations were completed to establish the relative percent variation and the necessary corresponding reservoir pressure based on the design inputs. The results are compared to the calculated strength of the ConocoPhillips design (Stalder, 2012). For the injector, using a base case well diameter of 0.17 m OD, a heterogeneous case and longer wellbore will be considered. For a varying height reservoir, ICD design for proportional steam distribution is suggested. The objective is to size ICDs appropriately to ensure that reservoir and frictional effects are minimized for proportional fluid distribution along the well. For the production well, the base case wellbore diameter of 0.17 m OD was used for different BHPs for both a homogeneous and heterogeneous reservoir with varying strengths of ICDs.

The relative percent difference in heel-toe rate variation is calculated with Equation 4. A value closer to zero suggests that the flow is more uniformly/evenly distributed.

\[
\% \text{ Relative Difference} = \frac{\text{Max flow rate} - \text{Min flow rate}}{\text{Average}} \times 100 \quad (4)
\]
**Simulation Software - Thermal Wellbore Simulator (TWBS)**

For the completion simulation, Thermal Wellbore Simulator (TWBS) was used produced by Thomas Tan and Associates at PetroStudies Inc. TWBS is a steady state commercial wellbore modeling software program that uses a multi-segment wellbore model coupled to a reservoir cells, commonly used for SAGD design applications. The software uses the Peaceman equation for productivity, Equation 5.

\[
PI = \frac{2\pi kh}{\mu \ln \left( \frac{r_a}{r_w} \right)} \quad (5)
\]

The equivalent radius of the well block, \(r_a\), is calculated through Equation 6, and DX and DY are the grid lengths defined by the user.

\[
r_a = 0.14(DX^2 + DY^2)^{0.5} \quad (6)
\]

The Peaceman equation (Peaceman, 1993), a modified equation of Darcy’s Law for radial flow, is a simple equation used to tie the simulation grid size to a productivity index (PI). The multi-phase flow correlation is from Beggs and Brill (Beggs and Brill, 1973) for calculation the hydraulic performance, based on PVT properties input by the user. The injector model is initialized through rate, quality, and reservoir pressure. For the producer well, the BHP and reservoir pressure is used for initialization (Medina and Wat, 2012; T.T& Associates Inc.; Wang et al., 2010).

**Assumptions**

Within the simulation software, the wellbore is split into 10 m alternating segments of open flow representing an ICD and open joints with blank pipe, separated by packers. The set-up is displayed Figure 4. For an 800 m long well, this equates to 40 ICDs. The packers prevent axial flow which is assumed to exist in the reservoir. The pressure drop across the reservoir, \(\Delta P_{\text{reservoir}}\) is provided by Equation 5. The general equation representing flow across an ICD, \(\Delta P_{\text{ICD}}\), is represented by Equation 7 for channel flow. However, within the program the \(\Delta P_{\text{ICD}}\) is modeled through setting “Transmissibility”, a liner relationship between rate and pressure, Equation 8. Along the well, \(\Delta P_{o}\), based on Beggs and Brill (1973) friction is calculated through Equation 9.

\[
\Delta P_{\text{ICD}} = a_{\text{ICD}} * q^2 \quad (7)
\]

\[
\text{Transmissibility} = \frac{q}{\Delta P} \quad (8)
\]

\[
\Delta P_{f} = \frac{2f_{ICD} q^2 k_{NS} L}{144 \mu L} \quad (9)
\]

Since the pressure drop across the ICD is proportional to rate squared, at high Reynolds numbers (turbulent flow) \(\Delta P_{f}\) is proportional to the flow squared), the simulation should give a constant ratio of \(\Delta P_{\text{ICD}}\) over \(\Delta P_{f}\) for varying flow rates for the same wellbore diameter. Turbulent flow is expected for the injector well due to the low density.

**Base Case Parameters – Injector Well**

For the injector simulation, unless otherwise stated, the reservoir scenario parameters used are shown in Table 4. Based on Statoil operations at the Leismer site, the maximum WHP is 6000 kPa. For the simulation the injection rate is fixed and the WHP is variable below 6000 kPa. The conventional SAGD injection well parameters, modeled for comparison are displayed in Table 2, the schematic is displayed in Figure 5. For the wells with ICD completions, there is an ICD alternated between blank, no flow, pipe segments as shown in Figure 4 in the horizontal section of the well. For example, for an 800 m horizontal length, there are 40 ICDs. The wellbore dimensions are displayed in Table 5. The casing dimensions are the same from the liner to the wellhead at the surface. The surrounding reservoir grid dimensions, DX and DY are set at 50 m to represent what would be a “developed” steam chamber. There was little effect on results when the grid block size was changed. For steam injection in the reservoir, the relative permeability of steam is irrelevant at steady state as it can be assumed that the only fluid in the near wellbore region is steam. Near the wellbore it is assumed that all connate water has been vaporized, heating and displacing the oil.
Base Case Parameters – Production Well

For the producer, due to the limited knowledge of the emulsion behavior in the wellbore and reservoir, water was used as the simulation fluid. This is appropriate for an oil in water emulsion, as the reservoir fluid down hole is subject to debate. Typical water cut from SAGD operations is ~ 80%. Only the horizontal section of the well was modeled for simplicity with a set BHP. The parameters are shown in Table 3. For the production well, the same pipe dimensions for the injector apply to the producer shown in Table 3. An initial fluid temperature of 215 °C for the reservoir ensures conditions above the steam saturation temperature, and produces a 15 °C subcool to prevent steam flashing in the reservoir. The grid dimensions, DX and DY are taken as 10 m, which is more representative of the fluid surrounding the wellbore. The relative permeability of the fluid was taken as 0.2 for the original 5000 mD reservoir. This value is highly uncertain as many combinations provide the same results.

Results – Injection Well

Well Comparison - Homogeneous Reservoir

Simulation rate profile results from TWBS for a homogeneous reservoir with 5000 mD permeability are shown in Figure 6 for a conventional SAGD well and a well with ICDs of different strengths for a 0.17m OD liner. The ideal rate for proportional distribution is also displayed. There is a high out flux of flow at the heel for the conventional SAGD injector, compared to the two cases with ICDs. Figure 7 displays the outflow distribution profile for five different strengths of ICDs.

In Table 6 the percent difference between the maximum and minimum injection rates per meter (calculated using Equation 4), ΔP_{ICD} and necessary WHP are displayed, along with three other different strengths of ICDs.

---

**Table 2 - Conventional SAGD Injection Well Base Case Parameters**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fluid</td>
<td>Steam</td>
</tr>
<tr>
<td>Steam Quality (%)</td>
<td>95</td>
</tr>
<tr>
<td>Maximum WHP (kPa)</td>
<td>6000</td>
</tr>
<tr>
<td>Measured Depth (m)</td>
<td>430</td>
</tr>
<tr>
<td>Well Horizontal Length (m)</td>
<td>800</td>
</tr>
<tr>
<td>Pipe Roughness (m)</td>
<td>0.00004</td>
</tr>
<tr>
<td>DX = DY (m)</td>
<td>50</td>
</tr>
<tr>
<td>Length per Segment (m)</td>
<td>10</td>
</tr>
<tr>
<td>Reservoir Pressure (kPa)</td>
<td>3040</td>
</tr>
<tr>
<td>Reservoir Temperature (ºC)</td>
<td>233.5</td>
</tr>
<tr>
<td>Reservoir Permeability (mD)</td>
<td>5000</td>
</tr>
</tbody>
</table>

**Table 3 - Production Well Base Case Parameters**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fluid</td>
<td>Water</td>
</tr>
<tr>
<td>Measured Depth (m)</td>
<td>430</td>
</tr>
<tr>
<td>Well Horizontal Length (m)</td>
<td>800</td>
</tr>
<tr>
<td>Pipe Roughness (m)</td>
<td>0.00004</td>
</tr>
<tr>
<td>DX = DY (m)</td>
<td>10</td>
</tr>
<tr>
<td>Skin</td>
<td>100</td>
</tr>
<tr>
<td>Reservoir Pressure (kPa)</td>
<td>3040</td>
</tr>
<tr>
<td>Reservoir Temperature (ºC)</td>
<td>215</td>
</tr>
<tr>
<td>Reservoir Permeability (mD)</td>
<td>1000</td>
</tr>
<tr>
<td>Permeability to Fluid (mD)</td>
<td>0.2</td>
</tr>
</tbody>
</table>

**Table 4 - Injection Well Base Case Parameters**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fluid</td>
<td>Steam</td>
</tr>
<tr>
<td>Steam Quality (%)</td>
<td>95</td>
</tr>
<tr>
<td>Maximum WHP (kPa)</td>
<td>6000</td>
</tr>
<tr>
<td>Measured Depth (m)</td>
<td>430</td>
</tr>
<tr>
<td>Well Horizontal Length (m)</td>
<td>800</td>
</tr>
<tr>
<td>Pipe Roughness (m)</td>
<td>0.00004</td>
</tr>
<tr>
<td>DX = DY (m)</td>
<td>50</td>
</tr>
<tr>
<td>Length per Segment (m)</td>
<td>10</td>
</tr>
<tr>
<td>Reservoir Pressure (kPa)</td>
<td>3040</td>
</tr>
<tr>
<td>Reservoir Temperature (ºC)</td>
<td>233.5</td>
</tr>
<tr>
<td>Reservoir Permeability (mD)</td>
<td>5000</td>
</tr>
</tbody>
</table>

**Table 5 - Liner dimensions for Injector and Producer**

<table>
<thead>
<tr>
<th>OD (m)</th>
<th>OD (m)</th>
<th>Weight (lb-ft)</th>
<th>ID (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>7</td>
<td>0.178</td>
<td>26</td>
<td>0.159</td>
</tr>
<tr>
<td>6 5/8</td>
<td>0.168</td>
<td>24</td>
<td>0.150</td>
</tr>
<tr>
<td>5 1/2</td>
<td>0.140</td>
<td>20</td>
<td>0.121</td>
</tr>
</tbody>
</table>

Figure 5: Conventional SAGD well schematic
As the pressure drop across the ICD increases, the lower the heel-toe variation. The penalty is an increased WHP necessary to maintain the reservoir pressure of 3040 kPa and ensure the desired injection rate is maintained. Based on multiple simulations, the relative percent heel-toe variation for each pressure drop across the ICD for the 0.17 m OD liner at an injection rate of 500 CWE m$^3$/d with the necessary WHP is shown in Figure 8. For comparison, the calculated strength (~18 bar/(m$^3$/d)$^2$) for the ICD selected by ConocoPhillips (Stalder, 2012) is also displayed (340 kPa pressure drop across each device for an injection rate of 550 CWE m$^3$/d across 41 devices) in Figure 8.
Heterogeneous Reservoir- Injector Well

The conventional SAGD well, high and low strength ICD cases for the 0.17 m liner, similar to the simulation from Figure 6 were run with random permeability values ranging from 0 to 10,000 mD (for illustrative purposes) for the adjoining reservoir cells, shown in Figure 9, at an injection rate of 500 CWE m³/d. An increase in permeability at the heel will cause a greater variation in flux distribution with more steam injected at the heel and less along the remainder of the well. Less variation between the heel and toe will occur in the case of higher permeability at the toe. For a lower permeability reservoir, the flow profile will be more uniform as the Darcy effect will be less. The conventional SAGD injector well is sensitive to changes in permeability. As the reservoir pressure is the boundary condition for the simulation, with varying permeability along the wellbore, the WHP will increase as shown in Table 6. This is due to the change in distribution of the fluid.

![Figure 9: Rate per meter for conventional SAGD injector and wells with ICDs for random near wellbore permeability variations, for an injection rate of 500 CWE m³/d.](image)

The 0.17 m liner with varying ICD strengths was then applied to a heterogeneous reservoir with random permeability (same permeability profile as in Figure 9). Table 6 displays the WHP, ΔP_{ICD}, ΔP_{friction}, and magnitude of pressure drop across the ICD to frictional losses for the heterogeneous cases. The pressure drop across the ICD changed, as expected, due the effect of Darcy flow into the reservoir and the change in distribution of flow as there are several “no flow zones”.

Injector ICD Results Summary

Overall there is not a large difference in percent variation between the homogeneous and heterogeneous cases for the wells with ICDs. There is a large difference between the homogeneous and heterogeneous cases for the conventional SAGD injection well. This demonstrates the benefits of the ICDs for reducing outflow distribution sensitivity to permeability. The pressure drop in the liner of the conventional SAGD well is small in comparison as most of the fluid is injected at the heel of the well (less fluid transported down the annular space between the heel tubing and casing).

<table>
<thead>
<tr>
<th>Conventional (no ICDs)</th>
<th>Homogeneous (5000 mD)</th>
<th>Heterogeneous (0 – 10,000 mD)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>ΔP_{ICD} (kPa)</td>
<td>WHP (kPa)</td>
</tr>
<tr>
<td>a_{ICD} = 14</td>
<td>-</td>
<td>4375</td>
</tr>
<tr>
<td>a_{ICD} = 20</td>
<td>212</td>
<td>3540</td>
</tr>
<tr>
<td>a_{ICD} = 24</td>
<td>310</td>
<td>3630</td>
</tr>
<tr>
<td>a_{ICD} = 30</td>
<td>380</td>
<td>3690</td>
</tr>
<tr>
<td>a_{ICD} = 80</td>
<td>460</td>
<td>3760</td>
</tr>
</tbody>
</table>

Effect of Liner deployed ICDs for SAGD Injector Well – Homogeneous Reservoir

The magnitude of the pressure drop across the ICDs is greater than the frictional losses in the horizontal well bore. Based on the friction equation, Equation 9, the larger the diameter of the liner, the smaller the frictional pressure losses. Figure 10...
displays the frictional pressure losses along the wellbore for 3 different liner diameters equipped with ICDs for a heel toe variation of less than 10%. The pipe OD and ID dimensions are found in Table 5.

![Graph](image)

Figure 10: Frictional losses across the horizontal section of the injector well for a rate of 500 CWE m³/d, in a homogenous reservoir.

For the three diameters the WHP, ΔP_{ICD}, a_{ICD}, and the magnitude of pressure drop across the ICD to frictional losses are shown in Table 7. For the 0.14 m OD diameter liner it is important to recognize that for a heel-toe variation less than 10% the WHP is above the recommended maximum operating pressure of 6000 kPa (highlighted in red). As the frictional pressure drop along the liner increases, a larger in magnitude pressure drop across the ICD is necessary to compensate for the liner frictional losses. The frictional losses along the liner are different due to the different BHP pressure, affecting steam density. At a higher pressure the steam will have a higher density, causing an increase in frictional losses. As the reservoir pressure is constant at 3040 kPa the BHP is increased to compensate for a higher strength ICD.

<table>
<thead>
<tr>
<th>Outer Diameter (m)</th>
<th>Average ΔP_{ICD} (kPa)</th>
<th>Strength, a_{ICD} (bar/(m³/d)²)</th>
<th>WHP (kPa)</th>
<th>P_i (kPa)</th>
<th>ΔP_{ICD}/ΔP_i</th>
<th>% Heel-toe variation (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.14</td>
<td>3420</td>
<td>220</td>
<td>6970</td>
<td>220</td>
<td>15</td>
<td>9.7</td>
</tr>
<tr>
<td>0.17</td>
<td>1240</td>
<td>80</td>
<td>4475</td>
<td>95</td>
<td>13</td>
<td>9.3</td>
</tr>
<tr>
<td>0.18</td>
<td>890</td>
<td>58</td>
<td>4070</td>
<td>75</td>
<td>12</td>
<td>9.6</td>
</tr>
</tbody>
</table>

**Longer Wellbore – Injector Well**

Typical SAGD operations are limited by the length of the wellbore due to frictional losses causing high variations in sand face pressures and consequently outflow distribution. ICDs reduce the effect of friction, allowing for longer wellbores. Simulations were conducted for horizontal well lengths of 1000 m and 1200 m at injection rates of 600 and 800 CWE m³/d for a liner OD of 0.17 m. For a longer wellbore and higher rate, due to the higher frictional pressure drop, a large ICD is needed to minimize heel toe variation. This theoretical case is highly dependent on ideal reservoir characteristics (laterally extensive) and the length of the production well. Results of the simulation and recommended strength across the ICD are shown in Table 8.

<table>
<thead>
<tr>
<th>Length (m)</th>
<th>Rate (CWE m³/d)</th>
<th>WHP (kPa)</th>
<th>ΔP_{ICD} (kPa)</th>
<th>a_{ICD} (bar/(m³/d)²)</th>
<th>P_i (kPa)</th>
<th>ΔP_{ICD}/ΔP_i</th>
<th>% Max/Min Variation (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1000 (50 ICDs)</td>
<td>600</td>
<td>4575</td>
<td>1180</td>
<td>82</td>
<td>165</td>
<td>7.1</td>
<td>17.1</td>
</tr>
<tr>
<td>Conventional</td>
<td></td>
<td>4860</td>
<td>-</td>
<td>12</td>
<td>-</td>
<td>-</td>
<td>191</td>
</tr>
<tr>
<td>1200 (60 ICDs)</td>
<td>800</td>
<td>5445</td>
<td>1840</td>
<td>72</td>
<td>250</td>
<td>7.3</td>
<td>17.8</td>
</tr>
<tr>
<td>Conventional</td>
<td></td>
<td>5910</td>
<td>-</td>
<td>18</td>
<td>-</td>
<td>-</td>
<td>193</td>
</tr>
</tbody>
</table>

**Proportional Steam Distribution for Increasing Thickness Reservoirs**

Uniform steam distribution is ideal for a reservoir of uniform height. However, for a reservoir with increasing net pay thickness towards the toe, visible from seismic interpretation, a proportional height-to-rate ratio may be considered in the design. As expected, to deliver steam at the toe, a higher strength ICD at the heel and lower at the toe is necessary to choke the flow. For this simulation the wellbore was divided into three segments, with a target height ratio, target total flow, and
injection rate through each ICD. The required pressure drop across the ICD for the target rate is shown for each segment, in Table 9. The design may also be modified for variations in permeability along the liner.

| Table 9 - Target rate for varying pay thickness reservoir, Q = 500 CWE m³/d |
|---------------------------------|----|----|----|
| Segment                        | 1  | 2  | 3  |
| Length (m)                     | 260| 260| 280|
| Number of ICDs                 | 13 | 13 | 14 |
| "Higher" Segment Heights       | 10 | 15 | 20 |
| % Flow to each segment          | 20 | 35 | 45 |
| Target Segment rate (CWE m³/d/m)| 0.4| 0.6| 0.8|
| Flow through each ICD (CWE m³/d)| 8.4| 12.8| 15.9|
| ΔP₁ (kPa)                      | 95 | 45 | 9  |
| ΔP_{ICD} (kPa)                 | 350| 275| 250|
| ΔP_{ICD}/ΔP₁                   | 4  | 6  | 27 |
| a_{ICD} (bar/(m³/d)²)          | 80 | 18 | 10 |

The flow rate per meter and reservoir height for the varying height reservoir along the length of the wellbore are shown in Figure 11.

![Figure 11: Rate per meter along the horizontal section of the liner for a varying height reservoir split into three segments. The target rates and strength a_{ICD} of each segment are found in Table 9. Segment 1 is the left segment, 2 the middle and 3 the right.](image)

**Results - Production Well**

**ICD Strength vs. Rate Relationship**

For simplification, simulations for the production well were conducted with TWBS; however as a SAGD production well is equipped with a variable-speed ESP, only the horizontal section of the well was modeled with a target BHP. Four BHP values were selected, above the saturation pressure of steam at 215 °C (which is ~2450 kPa). At the specified BHP pressure for a 1000 mD homogeneous reservoir (relative permeability of 0.2 applied to a 5000 mD), the average rate per meter and pressure variation for varying “strength” is displayed in Figure 12. The strength (~1.7 bar/(m³/d)²), 28 kPa pressure drop for a 750 m³/d production rate across 59 devices ) and corresponding rate per length (.83 m³/d/m) for the ConocoPhillips (Stalder, 2012) field example, is also displayed on the graph for reference. For design, the rate is selected and ideal heel-toe variation to determine the necessary ICD strength and pump to provide the necessary BHP.
Evaluation of the Design of Liner Deployed Inflow/Outflow Control Devices for SAGD Wells

Figure 12: Strength and corresponding rate per meter, and heel-toe variation for a SAGD producer well for four difference BHPs

Production Well - Homogeneous Reservoir

Similar to the injection well scenario, a conventional open hole SAGD well with an OD of 0.17 m was simulated for comparison. The profile for a conventional SAGD well and two different strength ICDs completions for similar rates are shown in Figure 13. The production rate is approximately 710 m$^3$/d. More information on the simulation results are shown in Table 10. Taking into account the assumptions of low permeability, compared to injector, and high skin (Skin = 100), the rates along the wellbore are relatively uniform. However, if the pressure drop from the skin was substantially less, there would be a much less uniform profile. The frictional effect in the horizontal section of the well is quite minimal along the length of the liner.

Table 10 - Production Well Flux Comparison - Homogeneous Reservoir (5000 mD)

<table>
<thead>
<tr>
<th></th>
<th>BHP (kPa)</th>
<th>Rate (m$^3$/d)</th>
<th>$\Delta P_{ICD}$ (kPa)</th>
<th>$P_f$ (kPa)</th>
<th>$\Delta P_{ICD} / P_f$</th>
<th>%Heel Toe variation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional SAGD well</td>
<td>3015</td>
<td>713</td>
<td>-</td>
<td>3.0</td>
<td>-</td>
<td>11.2</td>
</tr>
<tr>
<td>$a_{ICD} = 0.40$</td>
<td>2975</td>
<td>707</td>
<td>12.4</td>
<td>3.4</td>
<td>3.7</td>
<td>5.4</td>
</tr>
<tr>
<td>$a_{ICD} = 2.0$</td>
<td>2925</td>
<td>710</td>
<td>62.2</td>
<td>3.3</td>
<td>18.6</td>
<td>3.0</td>
</tr>
</tbody>
</table>

Production Well – Heterogeneous Reservoir

The same permeability variation as the injector profile in Figure 9 was run for the producer cases - with a relative permeability multiplier of 0.2 for the reservoir fluid (water). The flux profile per meter of the three wells is shown in Figure 14 for a production rate of approximately 525 m$^3$/d. The higher the strength of the ICD, the smaller the influx variation from the reservoir. It should be noted that to match the production rates, the BHP was adjusted (a higher BHP will provide a higher production rate). The results are summarized in Table 11.
Discussion

Based on simulations reported from previous authors (Damas et al., 2009; Perdomo et al., 2008; Tachet et al., 2009) and steady-state simulations from this analysis, ICDs are shown to be an effective completion for SAGD wells to reduce the impact of frictional losses along the liner. No available literature has looked at liner deployed devices however this analysis proves the effectiveness of the device as a completion method. This analysis serves as a basis for initial design of necessary pressure drops across the devices for specified rates. Higher strength ICDs are more effective in eliminating the sensitivity to variations in permeability. The results are similar to what is expected for a conventional well analysis. This is based on the simplification of input parameters and single phase fluids modeled. However, for SAGD it is important to note that operating conditions of the reservoir are highly influenced by the wellbore design, such as steam injection pressure controlling the reservoir pressure and subcool control. The operating parameters are used as a mechanism of reservoir control.

There are very limited applications of ICDs for steam injection documented. It is apparent that even with a low strength ICD there is a more uniform distribution of steam compared to conventional heel and toe injection to achieve balanced flow. For a conventional SAGD well with injection at the heel and toe, reservoir effects dominate the distribution due to the high mobility of steam and low density. For an injection well, ICDs help to provide more uniform flow, however the penalty is a higher WHP. This may have economical and safety implications. For a highly heterogeneous reservoir the heel-toe variation increases, however for well with ICDs, the distribution will remain relatively uniform as the steam flow is controlled in the liner. This analysis only looked at ICDs with strengths above 14 for the injector. Further simulations are recommended to assess the impact of lower strength ICDs.

The simulations only considered wells with uniform strength devices along the wellbore. Potentially, a more effective ICD design may be to monotonically decrease the ICD strength towards the toe of the well. As well, ICDs may be designed for local variations of permeability- ideal if areas of no flow, such as low permeable zones (i.e., finer grained intervals), are found from well logs. Proportional steam distribution with ICDs for reservoirs with varying heights has also been shown to be a design possibility. ICDs can be useful for proportional and controlled steam placement, for example avoiding an aquifer or for placing steam in bitumen containing areas. Alternatively, to provide more control, ICDs may be incorporated with ICVs which have a dynamic pressure rate relationship.

The direct benefits are slightly less obvious in a production well as there is a tradeoff between productivity and inflow equalization with a higher strength. With a higher strength device, a higher BHP is necessary for a given production rate. Subcool is variable reflecting how close the hot produced water is to the saturation state. The height of the liquid level above the wellbore can be inferred based on the subcool value. It is used to control the production rate from the reservoir with a higher choke. The pressure in the well cannot exceed the fluid saturation pressure or flashing will occur in the well or near
wellbore area. For example for production fluid temperatures at 215 °C, the saturation pressure is about 2000 kPa, at 225°C the saturation pressure is 2550 kPa, limiting the available drawdown.

The length of SAGD wells is limited due to high frictional losses in the injector as well as the difficulty in regulating subcool over long well lengths. ICDs may be effective in maintaining a liquid level, allowing for longer wellbores with a higher strength ICDs used to provide more control. Ideally, with longer wellbores there is the potential of requiring fewer pads for the same reservoir area, therefore limiting land surface usage and reclamation. Installing ICDs will allow for the removal of the tubing string, as steam can be distributed through only the liner. This may decrease the size of the wellbore which may lead to a decreased capital cost with smaller liners and hole dimensions. However, with a smaller wellbore there are greater frictional losses thus a higher strength ICD is recommended to compensate.

At the Troll oil field ICDs with an industrial strength of 3.2 bar (converted to \( a_{ICD} = 3.2 \text{ bar/(m}^3\text{d})^2 \)) are installed along the length of the wellbore for a production well with a horizontal length of 2500 m (Henriksen et al., 2006). This is a higher strength than what was used for the simulations for the homogeneous reservoirs for this study at 0.4 and 2.0. SAGD wells are only 800-1000 m long; therefore there are less frictional losses along the liner. ConocoPhillips (Stalder, 2012) at their Surmont field, used an ICD strength of 1.7 bar for slightly higher rates and longer well design.

There is a lack of literature available on the modeling of SAGD production wells. The input parameters used in this study are based on a Leismer field data for a sandface pressure drop of ~200 kPa for 600 m/d, for water inflow. Many possible variations of permeability and skin provide the same results. Flow control is much less challenging due to the lower pressure drop along the wellbore (pressure drop across horizontal section ~3 kPa). Further simulation will aid in evaluating different multiphase flow effects from emulsion production and different mobility and frictional effects. The high skin value of 100 acts as a choke from the reservoir to the well causing the reservoir influx to be quite uniform. Subcool control highly influences the rate influx, and is difficult to model as it is variable with time and pump speed. Within the program the reservoir and liquid level and not able to be modeled.

Based on the need to adjust steam rates entering the reservoir over time for SAGD wells, subcritical devices are recommended. Further review of the selected device over the range of operational phases is recommended to ensure the devices are suitable over a range of varying conditions is necessary. As ICDs would be operating in relatively high temperature environments, it is necessary that the long-term integrity and performance of the flow elements are considered through hydraulic and mechanical tests under varying flow conditions and steam properties. Manufacturer’s designs may limit the suitability of the devices. Erosion and wear affects should be modeled through numerical analysis, and physical testing performed to identify appropriate devices.

The benefit of liner deployed devices over tubing deployed is that there is no flow in the liner/tubing annulus. No method for isolation in SAGD wells has been made available yet. Axial flow in the annulus between the open wellbore and liner is considered negligible as the sand is assumed to collapse around the liner. Heat transfer was ignored as the operation is assumed to be in steady state. Heat transfer will affect steam properties (quality, density etc.). A drawback of a liner-deployed system is that it is non-retrievable. Another potential problem with ICDs and unconsolidated reservoirs is sand plugging of the devices; this decreases the effectiveness of the completion. With incorrect design and operations, erosion may be a problem if high velocities occur. For the producer a nozzle-type ICD is recommended, as it is nearly independent of viscosity. For the injector a device independent of density is recommended.

Coupled steady state models provide an initial step for design and allow for quick decision making. This is ideal for initial design when selecting the type and ICD size, as there are few input parameters, and little reservoir information necessary. In TWBS, due to the nature of the calculation of the pressure drop for the ICD relationship, different rates cannot be modeled for the same model configuration. The limitations of the software do not allow for accurate modeling of ICD relationships, but rather the software provides suggested pressure drops based on injection rates for particular steam qualities and production rates.

In order to justify the economics of ICDs, reservoir simulation with a multi-segment well model is suggested for assessing the appropriateness of the ICDs over time (transient solution results) due to the set response to dynamic conditions, appropriate liner diameters, locations along the well and potential well placement in the reservoir (well spacing, etc.). Reservoir simulation is necessary for ICD spacing to ensure that oil recovery is not compromised and to model the effects of devices installed in both the injector and producer. As the impact of varying length scales of heterogeneity away from the wellbore cannot be modeled in the steady state simulator, simulations are necessary for assessing the impact of ICDs and for proving their suitability in the reservoir. The presence of shale in the reservoir will also have an effect on the heating provided by the steam. Going forward models can be history matched against measured data to predict future production for the operating scenarios.
**Conclusion**

ICDs function in a similar way in SAGD as conventional operations; however, there are differences in operations that must be considered. The model is similar to conventional implementation except that the injected steam phase has a lower viscosity than water, increasing. This analysis neglected thermal effects and modeled only single phase injection/production. Although there are benefits with installing ICDs, the penalty is a higher WHP or lower BHP for a given injection or production rate.

Using TWBS software, steady-state simulations allow for an initial overview of necessary strengths with little reservoir information necessary. The scenarios were for an injector and producer well with liner deployed uniform devices. To keep results generic, a “strength” value was calculated to relate the pressure drop and flow rate through each device. ICDs prove to reduce the impact of geological heterogeneity as well as frictional losses along the liner. Generic design allows for design despite variations in permeability along the wellbore. Based on this analysis it is recommended to use the pressure drop across the ICD at the design rate to determine an appropriate ICD, and to further model the design in a completion simulator with the appropriate ICD relationship built in.

The higher the strength, the smaller the heel-toe variation for the influx or outflux. This may have economical as well as environmental implications if higher pressure steam is required to maintain the ideal reservoir pressure (a higher WHP is necessary). For modeling the ICDs for the injector the WHP was variable and rate fixed. Even with a lower strength ICD, the proportional stream distribution along the length of the wellbore improved compared to a conventional SAGD well. The greatest impact was shown in heterogeneous reservoirs. When implementing an injector design it is important to consider that a lower pressure reservoir will mean lower steam saturation temperature and drainage rate due to a higher bitumen viscosity.

For the production well, only the horizontal section of the well was simulated. For the producer the BHP was fixed and rate variable. Due to the lack of available information on SAGD production wells, there is uncertainty on permeability and skin values in the near wellbore region. As well, subcool used to control the wells is variable. There is also high uncertainty on the emulsion properties down hole. For this reason only water was used in the simulations. More simulation on the production well is necessary to further understand the effect of temperature (subcool), skin and permeability. Modeling with a different fluid will have different reservoir mobility and wellbore frictional affects along the wellbore.

Better steam distribution means there is a higher potential for oil recovery. ICDs help to homogenize the pressure distribution across the well to achieve balanced inflow or outflow by reducing the impact of frictional pressure loss in the injector and the producer. There is an economic balance for the WHP, BHP, flow rates, desired variation and therefore corresponding ICD strengths for the injector and producer wells. With uniform steam distribution the steam chamber will potentially be more uniform allowing for high rates and reduced CSOR. By maintaining a uniform liquid level above the producer the ultimate goal is to decrease the BHP for higher production rates reducing the concern for having steam breakthrough. Installing ICDs allows for the possibility of removing the toe string (for the injector) allowing for cheaper wells, potentially reducing the diameter of the current liner, increasing the length of SAGD wells beyond the typical lengths of 800-1000 m and providing proportional steam distribution.

**Nomenclature**

- $\Delta P_{ICD}$: Pressure across the ICD
- $a_{ICD}$: Strength of ICD
- BHP: Bottom hole pressure
- CSOR: Cumulative steam to oil ratio
- CWE: Cold water equivalent
- D: inside pipe diameter
- DX: Segment width in the x-direction
- DY: Segment width in the y-direction
- $f_p$: two phase friction factor
- $G$: conversion factor
- $h$: segment length
- ICD: Inflow Control Device
- ICV: Inflow Control Valve
- ID: Inner diameter
- OD: Outer Diameter

**Subscripts and Greek**

- $k$: permeability
- $L$: length of pipe
- $P_r$: Reservoir pressure
- PVT: Pressure, volume, temperature properties
- $q_o$: Oil rate m³/d
- $r_o$: Equivalent radius of the well block
- $r_w$: wellbore radius
- $v$: velocity
- WHP: Wellhead Pressure

**References**


## Critical Literature Review

<table>
<thead>
<tr>
<th>Paper</th>
<th>Year</th>
<th>Title</th>
<th>Authors</th>
<th>Contribution</th>
</tr>
</thead>
<tbody>
<tr>
<td>SPE/PS-CIM/CHOA 97922</td>
<td>2005</td>
<td>Wellbore Hydraulics in a SAGD Well Pair</td>
<td>S. Das</td>
<td>Information on SAGD well injector and producer wells. Information provided on sub cool control to prevent steam breakthrough.</td>
</tr>
<tr>
<td>CJPT 2005-116</td>
<td>2005</td>
<td>Investigation of Key Parameters in SAGD Wellbore Design and Operation</td>
<td>P. Vander Valk, P. Yang</td>
<td>Simulation to model different design conditions and their impact on CSOR (cumulative steam oil ratio) and CDOR (bitumen production rate).</td>
</tr>
<tr>
<td>International Oil Conference and Exhibition 108700</td>
<td>2007</td>
<td>Inflow Control Devices: Application and Value Quantification of a Developing Technology</td>
<td>F.T. Al-Khelaiwi, D. Davies</td>
<td>Overview of different types of ICD devices and their suitable applications. Paper discusses sand control options, their application with Artificial Lift and modelling the well design in a reservoir simulator to optimize the well profile influx.</td>
</tr>
<tr>
<td>WHO 2008-450</td>
<td>2008</td>
<td>The Impact of Steam Placement Control on SAGD Performance: A Numerical Study from the Orinoco Heavy Oil Belt</td>
<td>L. Perdomo, C.P. Daman, E.F. Ricon</td>
<td>Simulation study to undersatange the impact of univorm steam distribution, through a sensitivity analysis on well placement etc. and the implementation of ICDs (incorporation of heat transfer effects and hydraulics). Results indicate that ICDS increase oil recovery.</td>
</tr>
<tr>
<td>WHO 2009-332</td>
<td>2009</td>
<td>Improve steam distribution in Canadian reservoirs during SAGD operations through completion solutions</td>
<td>E. Tachet, J. Alvestad, R. Wat, K. Keogh</td>
<td>Evaluation of outflow control devices for uniform steam chamber growth. The study is aimed at quantifying the effect of friction and heat exchange and the use of ICDs to reduce the effects of pressure and temperature drops. Results indicated that the reservoir heterogeneity as well as frictional pressure losses have a significant impact on the recovery and optimal design. Depending however on the length scale of the heterogeneity, ICDs may have no impact.</td>
</tr>
<tr>
<td>Paper</td>
<td>Year</td>
<td>Title</td>
<td>Authors</td>
<td>Contribution</td>
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<tr>
<td>WHO 2009.-392</td>
<td>2009</td>
<td>Improving productivity and steam conformance in SAGD wells</td>
<td>C.P. Damas, M. Nukhaev, D. Rudenko</td>
<td>Through dynamic thermal simulation with a multi segment well model for advanced completions, results indicated there is a potential to improve economic efficiency, improve steam conformance and prevent steam breakthrough. Possible configurations include uniform strength ICDs as well as monotonically increasing in cross section area along the wellbore.</td>
</tr>
<tr>
<td>SPE 124677</td>
<td>2009</td>
<td>Understanding the Roles of Inflow-Control Devices in Optimizing Horizontal-Well Performance</td>
<td>P. Fernandes, Z. Li, and D. Zhu, Texas A&amp;M University</td>
<td>Paper provides overview of ICD technology and the procedure to predict horizontal well performance with ICD's.                                                                periability, porosity, gamma ray and oil saturation suggesting pressure and geology are important aspects of design.</td>
</tr>
<tr>
<td>SPE 129694</td>
<td>2010</td>
<td>On the Relationship between Completion Design, Reservoir Characteristics, and Steam Conformance Achieved in Steam-based Recovery Processes such as SAGD</td>
<td>W. Wei and I. D. Gates</td>
<td>to obtain high efficiency, steam conformance along the wellbore is necessary. Analysis of SAGD Surmont data. Wellbore completion design criteria for uniform steam conformance: 1. Nature of the steam flow 2. Injection strategy 3. Mechanical strength and capability of the design Paper summarized a correlation for steam conformance based on operating pressure, horizontal permeability, porosity, gamma ray and oil saturation suggesting pressure and geology are important aspects of design.</td>
</tr>
<tr>
<td>CSUG/SPE 147543 SPE-150497</td>
<td>2011</td>
<td>Using a New Intelligent Completion Strategy to Increase Thermal EOR Recoveries–SAGD Field Trial</td>
<td>J. Shaw and M. Bedry</td>
<td>Evaluation of ICD and valves for use in SAGD reservoirs. For SAGD reservoirs ICDs are useful to prevent steam breakthrough, allow for steam conformance and uniform steam injection and chamber growth. Benefits of ICV over ICD are that an ICV can be opened or closed to assist with steam chamber growth which is based off of down hole temperature and pressure measurements</td>
</tr>
<tr>
<td>SPE 153706</td>
<td>2012</td>
<td>Test of SAGD Flow Distribution Control Liner System, Surmont Field, Alberta, Canada</td>
<td>J. L. Stalder</td>
<td>First field application of flow distribution control built into the horizontal liners for both the injection well and the production well.</td>
</tr>
</tbody>
</table>
**JCTP June 1993**  
**Effective Application of Steam Assisted Gravity Drainage to Long Horizontal Well Pairs**

**Authors:** N. Edmunds and S.D. Gittins

**Contribution:** Overview of design parameters to ensure conductive heating and reducing adverse pressure such as interwell spacing, liner and tubing diameters, and tubing completion design.

**Objectives:** Conditions necessary to initiate drainage along the well pair. Results stress the importance of steam entry and its impact on production. Impact on the circulation phase, wellbore pressure gradients, optimum lengths and wellbore sinuosity.

**Methodology used:** Numerical simulation in 2D and 3D. Incorporation of operating parameters used at UTF testing facility.

**Conclusions:** Necessary to operate wells to ensure pressure gradients are imposed in the reservoir to prevent liquid accumulation. Well length is dictated by the reservoir quality and hydraulics.

**Comments:** Very commonly referenced paper. Economics evaluation of SAGD projects is a multidisciplinary activity. Suggests that Limited Entry is not an appropriate method for uniform steam distribution once drainage is initiates due to heterogeneities in the reservoir and pressure fluctuations, as well poses potential sand control issues.
Investigation of SAGD Steam Trap Control in Two and Three Dimensions

Authors: N. Edmunds

Contribution: First paper to compare 2D and 3D models for steam trap production control (maintaining the BHT just below the boiling point and to ensure liquid does not build up in the producer)

Objectives of the paper: Effect of production subcool, reservoir state, and economic performance for an Athabasca reservoir. Subcool is used as a means to control steam flow into the reservoir.

Methodology used: Wellbore simulation in 2D and 3D along with the analysis of field data.

Conclusions: Economic optimum steam trap recommended to be between 20-30 °C. Difficult to control the inflow temperature of specific segments.

Comments: Very commonly referenced paper. ICDs not considered in the analysis. Control/impact will have an impact on subcool control which is measured.
SPE/PS-CIM/CHOA 97922 (2005)
Wellbore Hydraulics in a SAGD Well Pair

Authors: S. Das, ConocoPhillips

Contribution: Assessment of issues present in SAGD wellbore design such as: steam breakthrough in one segment of the well, buildup of liquid level between the wells, uniform steam distribution with heat transfer (injection well), and tubular design.

Objective of the paper: Wellbore design, producer and injection design, and startup conditions for optimum steam chamber. Wellbores must be designed with the fluid rate within the well

Methodology used: Simulation software to determine a base-type well factoring in liquid level maintenance to prevent steam breakthrough. The effect of deviation and frictional losses effect tubular friction/diameter. Operating pressures and facility pressure dictate possible flow and steam quality. Evaluation of concentric design, with easier intervention (long string for toe injection/production, annular region for heel injection/production) and parallel design (long (toe) and short (heel) tubing strings for injection/production).

Conclusions:
1. Injector design is critical to prevent early steam breakthrough, design to mitigate
2. Circulation (startup phase) of steam is critical for uniform steam chamber growth
3. Steam production at the surface during startup phase does not indicate presence of live steam along the length of the well.
4. With the lack of temperature data in the wellbore it is difficult to determine the vapour quality at the surface due to counter current heat transfer of excess steam in horizontal section
5. Comments: Objective paper, very commonly references in literature.
**JCTP 2005**  
**Investigation of Key Parameters in SAGD Wellbore Design and Operation**

**Authors:** P. Vander Valk, P. Yang, Nexen

**Contribution:** Assessment and sensitivity analysis of critical factors that affect SAGD such as wellbore pressure drop and subcool control.

**Objectives:** Impact on steam chamber conformance, productivity and SOR at various operating pressures due to wellbore pressure drops. Impact of:
- Smaller Injection Tubing
- Larger Injection Liner
- Smaller Production Tubing
- Mid-sized Injection Liner
- Low Pressure Base Case
- Low Pressure Large Injection Liner
- Variable Slot Density on Injection Liner
- Alternate Completion Methods with Q-Flow

**Methodology used:** Numerical reservoir simulation to analyse steam chamber growth and wellbore simulation to assess the impact of completion design.

**Conclusions:** Cumulative bitumen production is sensitive to subcool for designs with high frictional pressure drop. Design wells for an even fluid level, steam trap over the well pair. The wellbore hydraulics impact artificial lift requirements and operating conditions.

**Comments:** Impact only assessed based on production not through NPV which would affect implementation.
SPE 1080700 (2007)
Inflow Control Devices: Application and Value Quantification of a Developing Technology

Authors: F.T. Al-Khelaiwi, SPE, Heriot-Watt University and Saudi Aramco, and D.R. Davies, SPE, Heriot-Watt University

Contribution: Overview of ICD literature, ICD types, methods to establish the value they add and limitations of available software

Objectives: Technical paper to cover the basics of ICD design and case studies through examples. Provide a simple technique to model and optimize ICD completion configuration.

Methodology used: Wellbore modeling software in conjunction with reservoir simulation.

Conclusions: ICDs are effective to optimize well inflow for a wide range of reservoir environment. There is a lack of ICD modeling programs that adequately account for both annular flow and time dependent effects simultaneously.

Comments: The paper was written in 2007. ICD modeling has come a long way since then. This paper provides a simple overview of the devices and methods to model. Steady state and transient results are included.
The Impact of Steam Placement Control on SAGD Performance: A Numerical Study from the Orinoco Heavy Oil Belt

Authors: L. Perdomo, PDVSA, C.P. Damas and E.F. Rincon, Schlumberger

Contribution: Through simulation assess the impact of pressure and heat transfer losses along the horizontal section of SAGD wells. Sensitivity analysis of inter-well spacing, placement and evaluation of ICDs for steam placement control.

Objectives: Sensitivity analysis to evaluate the impact of steam injection rate, horizontal well length and tubing deployed ICD placement and inter-well spacing. Evaluation of software speed and performance

Methodology used: Multi-segment wellbore simulation in simulation grid (ECLIPSE).

Conclusions: Simulation successfully modeled wellbore hydraulics and heat transfer effects and is necessary for effective simulation. ICDs helped to increase recovery from 8% to 17%.

Comments: Basic cases and set up. Sensitivity considered different placements of ICDs. Results indicate that the impact of heat transfer may affect steam distribution and change the properties of steam. Results more qualitative than quantitative.
**WHOC 2009 -332**  
**Improve steam distribution in Canadian reservoir during SAGD operating through completion solutions**

Authors: E. Tachet, J. Alvestad, R.Wat, K. Keogh

**Contribution:** Simulation of ICDs through multi-segment wells for SAGD well pairs for injection wells.

**Objectives:** Use of multi-segment well coupled with reservoir modeling to evaluate different strengths of ICDs for different reservoirs. Simulations look at tubing deployed devices, with four ICDs along the well.

**Methodology used:** Reservoir modeling with multi-segments well option in Eclipse 300™.

**Conclusions:** With a BHP held constant, with higher strength ICDs, there is a lower steam pressure at the well-reservoir interface. Based on the properties of steam, this leads to a lower temperature, which, in turn, affects the produced fluid viscosity and therefore production rate. As well depending on the length scales of heterogeneity ICDs may not be effective in establishing a uniform steam chamber.

**Comments:** Work does not cover sensitivities on different OCD strengths, placements and number along the well according to geology.
WHOC 2009-392 (2009)
Improving productivity and steam conformance in SAGD wells

Authors: C.P. Damas, M. Nukhaev, and D. Rudenko, Schlumberger

Contribution: Simulation of ICDs for SAGD injector and producer wells based on typical Venezuelan reservoir characteristics. A conventional SAGD well pair was compared against wells completed with advanced screen and liner deployed ICDs.

Objectives: Highlight the impact of well completion design to improve SAGD efficiency.

Methodology used: Multisegment reservoir simulation to compare different operating scenarios.

Conclusions: ICDs are effective for balancing inflow for both the injector and producer. For the producer they are effective for preventing steam breakthrough and the injector in controlling steam distribution.

Comments: Results indicate that ICDs can be an effective application to improve SAGD efficiency. No other simulation study addresses the producer well. No data was provided on suggested pressure drop through the devices as the devices were set through nozzle diameters.
SPE 124677 (2009)
Understanding the Roles of Inflow-Control Devices in Optimizing Horizontal-Well Performance

Authors: Zhuoyi Li, SPE, Schlumberger; Preston Fernandes, SPE, Chevron; and D. Zhu, SPE, Texas A&M University

Contribution: Integrated analysis method between the inflow (reservoir) and outflow (wellbore) to generate a flow profile and appropriate applications of ICDs.

Objectives: Addresses when ICDs should be used and methodology to predict horizontal well performance.

Methodology used: Wellbore simulator coupled with a reservoir model to evaluate the flow rates and pressure distribution relationship. Analysis conducted for a highly permeable formation, a heterogeneous reservoir, a bottom water drive and gas-cap drive in thin formations.

Conclusions: ICD function is based on the pressure ratio of wellbore fraction to reservoir drawdown, if the frictional pressure drop is not significant ICDs could restrict oil flow. Overall an effective technology: uncertainty in the placement of ICD due to heterogeneity may have an insignificant impact on the production with an increase in cost.

Comments: ICDs have limited response to dynamic downhole conditions. Changes in the reservoir will occur with time, which are important to consider when incorporating into completion.
SPE 129694 (2010)
On the Relationship between Completion Design, Reservoir Characteristics, and Steam Conformance Achieved in Steam-based Recovery Processes such as SAGD

Authors: Wei Wei, SPE, and Ian D. Gates, SPE, Department of Chemical and Petroleum Engineering, Schulich School of Engineering, University of Calgary

Contribution: Analysis of the impact on completion design, operating pressure and reservoir geology on steam conformance.

Objectives: Address well completions design impacts on steam conformance such as nature of the steam flow in the injector, design of the injection strategy and mechanical strength of the completion design. Correlation to link operating pressure and oil saturation.

Methodology used: Use of down hole thermocouples data to track steam distribution.

Conclusions: Uniform steam conformance based on the relationship between well pressure and steam flow in the injector dynamics and reservoir heterogeneity. Design wells to offset variable flow distribution.

Comments: As the steam chamber grows, the effects of heterogeneity will change with time. Design completion for time-varying heterogeneity along the wellpair.
Reduction of the horizontal well’s heel-toe effect with inflow control devices

Authors: V.M. Birchenko, K.M. Muradov and D.R. Davies

Contribution: Quantitative analysis of ICDs applications to horizontal wells through analytical equations and Troll oil field analysis.

Objectives: Mathematical equations to allow for quick screening of ICDs for production wells.

Methodology used: Wellbore simulation and analytical equations from previous work

Conclusions: Equations require many parameters to effectively quantify the benefits of ICDs for the heel-toe effect and impact on the inflow performance relationship.

Comments: Interesting paper with complex math. Ideal for conventional production well, lots of variables are necessary for the calculations. Does not consider possible heat effects or many reservoir conditions.
CSUG/SPE 147543, SPE 150497 (2011)
Using a New Intelligent Completion Strategy to Increase Thermal EOR Recoveries—SAGD Field Trial

Authors: Joel Shaw and Mark Bedry, Halliburton

Contribution: Overview of an intelligent completions strategy for SAGD wells that incorporates interval control valves (ICVs), well segmentation, and instrumentation. Provides results from initial field trials.

Objectives of the paper: Description of the problem with traditional SAGD systems for steam chamber development. Through the use of pressure and temperature measurements injection and production are controlled through ICV’s.

Methodology used: Analysis of actual data through sliding sleeve ICVs.

Conclusions: Benefits of ICVs include: Transient pressure and temperature at shut-in, used for estimating steam chamber characteristics over time, injection into specific zones and preventing steam breakthrough. Reliable technology for use at 260°C.

Comments: Clear background on issues with traditional SAGD and how the incorporation of ICVs have helped with uniform steam distribution along the wellbore.
SPE 153706 (2012)
Test of SAGD Flow Distribution Control Liner System, Surmont Field, Alberta Canada

Authors: J. L. Stalder

Contribution: First paper to share success of liner deployed ICDs for SAGD injector and producer wells implemented at the field. Results are provided through 4D seismic and reduction in SOR. Evaluation of ICDs for steam placement control.

Objectives of the paper: Basic design values were provided from the injector and producer. The liner-deployed restrictors were designed to generate a pressure drop of 340 kPa (50 psi) for 550 m$^3$/d of steam for 41 devices at 85% steam quality for the injector. For the producer the ICDs were designed to give 28 kPa (4 psi) pressure drop for an emulsion rate of 750 m$^3$/d for 59 devices. Both wells were 6-5/8” base pipe and has a horizontal length of 900 m.

Methodology used: Field implementation at Surmont for injector and producer. Results quantified by 4D seismic.

Conclusions: Results indicated that the flow devices were successful in providing uniform steam distribution.

Comments: Background to project and modeling of injector and producer wells to determine a design method for ICD sizing. Results from the analysis are compared against the data provided from this analysis.
Appendix B  Parameters Affecting SAGD Operations

Reservoir Properties Affecting Steam Chamber Growth.
Geological influences on steam chamber growth include permeability, porosity, anisotropy, reservoir stress, thickness, and geometry. The fluid saturation and local variation will also impact the production rate. Additionally, the presence of thief zones and proximity to water can also have a negative impact (Das, 2005a; Singhal et al., 1998).

Wellbore Hydraulics Affecting Steam Chamber Growth.
The maximum length of SAGD well pairs depends on the reservoir quality and the hydraulic capacity, injector/producer spacing, design of the injection strategy, and mechanical strength ([Valk and Yang, 2005; Wei and Gates, 2010]. With a longer well, there is increased potential for non-uniform steam chamber growth due to greater matrix permeability and high mobility of steam (Parappilly and Zhao, 2009). Even distribution along the wellbore is a critical factor affecting steam chamber growth, with temperature variations along the well having an adverse effect (McCormack, 1997; Valk and Yang, 2005).

As with non-thermal horizontal wells, the impact of friction along the wellbore will affect the production and injection profiles. Other factors affecting production and steam distribution include: the completion configuration, wellbore profile (multiphase flow regime affected by undulations and sinuosity), and near wellbore effects. Annular pressure drop and steam quality distribution in the horizontal section are important design criteria for SAGD steam injection wells (McCormack, 2002). The pressure profile of the SAGD well pair is displayed in Figure B-1.

Operating Conditions Affecting Steam Chamber Growth.
There are three phases associated with SAGD operations: start-up or circulation, SAGD operation, and wind down. In the first phase, heating primarily occurs through convection as steam is circulated in both wells to establish ‘hydraulic communication’ of the fluid between the well pair ([Edmunds and Gittins, 1993; Edmunds et al., 1994]).

During the production phase, the lower well is converted to a production well. Drawdown on the well is responsible for oil rate and steam trap control The suggested steam injection rate is one that will maintain the desired steam chamber pressure by replacing the condensed steam (Edmunds et al., 1994). Thermocouples along the wellbore provide information to ensure optimal operational conditions.

A key variable for SAGD control is subcool, the temperature difference between the injected steam and produced fluids (Edmunds, 2000; Gates and Leskiw, 2008; Ito and Suzuki, 1996) This parameter is used for steam trap control, which is maintaining the BHT to just below the boiling point of water to prevent steam breakthrough.

Steam breakthrough may cause movement of sands and fines, leading to eventual erosion of the liner, as well as decrease the efficiency of the operations (Das, 2005a). The operating pressure plays a significant role in the rate of recovery. Authors Edmund and Chinna (2001) through simulation proposed optimum operating pressures for operations, based on reservoir type.
Appendix C  TWBS Inputs

Within the software the configurations of the injector and producer are shown in Figure C-2 and Figure C-1.

![Figure C-2: Injection Well schematic. Fluid will travel in the green pipe. Black segments, packers, indicate no flow](image1)

![Figure C-1: Production well schematic. Fluid will travel in the green pipe. Black segments, packers, indicate no flow.](image2)

The injector wellbore trajectory is shown in Figure C-3.

![Figure C-3: Injection well trajectory](image3)

The PVT properties of the water/steam for the injector and producer wells are in Table C-1 and Table C-2.

| Table C-1 - Temperature - Viscosity Relationship for water |
|---------------------------------|-----------------|
| Temperature (°C) | Viscosity (cp) |
| 0 | 1.79 |
| 6.8 | 1.44 |
| 26.8 | 0.857 |
| 46.8 | 0.579 |
| 66.8 | 0.423 |
| 86.8 | 0.32 |
| 100 | 0.282 |
| 126.8 | 0.219 |
| 176.8 | 0.153 |
| 226.8 | 0.118 |
| 276.8 | 0.095 |
| 326.8 | 0.076 |

| Table C-2 - PVT Properties of Water |
|----------------------------------|-----------------|
| Molecular Weight (kg/mol) | 18.02 |
| Pc (kPa) | 22105 |
| Tc (degK) | 647.2 |
| Density (kg/m3) | 1000 |
| Specific Gravity | 1 |
| Heat capacity | 0 |
| Compressibility | 5.8E-07 |
| CT 1 | 0.00072 |
| CT 2 | 0 |
Appendix D  Frictional Losses for different Liner Diameters- Injector
Table D-1 displays the frictional pressure losses along the wellbore at 3 different rates for 3 different diameters. Each well is completed with ICDs and have a heel-toe variation of less than 10%.

<table>
<thead>
<tr>
<th>Outer Diameter (m)</th>
<th>Rate = 400 m$^3$/d CWE</th>
<th>Rate = 500 m$^3$/d CWE</th>
<th>Rate = 600 m$^3$/d CWE</th>
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<tbody>
<tr>
<td>0.14</td>
<td>175</td>
<td>265</td>
<td>400</td>
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<td>0.17</td>
<td>65</td>
<td>95</td>
<td>130</td>
</tr>
<tr>
<td>0.18</td>
<td>50</td>
<td>72</td>
<td>105</td>
</tr>
</tbody>
</table>

Appendix E  Pressure drop across different strength ICDs.
The pressure drop across the ICDs along the wellbore are shown in Table D-1 for 5 strengths of ICD.

Figure E-1: Pressure drop across the "ICD" along the well for 4 different strength ICDs. Rate of 500 m$^3$/d and OD of 0.17 m
Appendix F  
**Sensitivity analysis of conventional SAGD well**

The sensitivity of the parameters for the conventional SAGD well are displayed in a tornado chart, Figure F-1. The greatest sensitivity is due to the permeability and roughness (frictional effects). The lower the permeability, the smaller the heel toe variation. The input parameters for the sensitivity analysis are shown in Table F-1.

<table>
<thead>
<tr>
<th>Table F-1 - SAGD Sensitivity Parameters</th>
</tr>
</thead>
<tbody>
<tr>
<td>Roughness (m)</td>
</tr>
<tr>
<td>Rate (CWE, m³/d)</td>
</tr>
<tr>
<td>K (mD)</td>
</tr>
<tr>
<td>Quality (%)</td>
</tr>
<tr>
<td>P, ± 10%</td>
</tr>
</tbody>
</table>

Figure F-1: Tornado chart of SAGD Injector well sensitivities.

Appendix G  
**Impact of increasing grid size - Injector**

In order to simulate steam chamber growth, the cell size in the y-direction was increased. However, doing so produced only a minimal effect on the rate. As the transmissibility was kept constant within the model (ΔP/q), the only effect on the flow was Darcy flow into the reservoir. The injectivity index (II), based on Peaceman is shown in Table G-1 for ranging grid sizes, along with the wellhead pressures and average pressure across the sand face and % heel-toe variance.

<table>
<thead>
<tr>
<th>Table G-1 - Effect of Increasing grid size</th>
</tr>
</thead>
<tbody>
<tr>
<td>DX</td>
</tr>
<tr>
<td>-----------------------------</td>
</tr>
<tr>
<td>BASE CASE</td>
</tr>
<tr>
<td>50</td>
</tr>
<tr>
<td>50</td>
</tr>
<tr>
<td>50</td>
</tr>
<tr>
<td>50</td>
</tr>
<tr>
<td>50</td>
</tr>
<tr>
<td>50</td>
</tr>
</tbody>
</table>
Appendix H  Subcritical vs. Critical Flow devices

The difference between Limited Entry Perforations (LEP) and ICDs is critical vs. subcritical flow. In LEP, the design is such that the size of the opening limits the flow rate into a zone at any pressure (Boone et al., 1998). The diameter is selected so that the flow is choked or at critical conditions. This is often used in cyclic steam cycling (CCS) production. Based on Chein (Chien, 1993) critical flow occurs when \( P_r < 0.61 \) \( P_w \). This is not ideal for SAGD wells as there is often a range of operating conditions the well will undergo, and rather than just place steam in a particular zone, uniform steam distribution is desired.

Using the Bernoulli equation to give an area of choke size is not ideal in this case as there is both a multiphase and turbulent flow of the steam. Instead, iterations were done to determine the appropriate choke diameter based on a steam quality of 95% for the base case well. The calculated area of the choke is in the subcritical range. Further analysis is necessary for proper design to ensure the critical erosional velocity is not met which will cause damage to the equipment, as well as implementation in thermal conditions.

Suggested Diameters

Sizing an appropriately sized ICD for steam distribution depends on the quality, inlet and outlet pressures, length of the choke and the quantity along the wellbore. Using a correlation for steam such as Chien’s correlation for “Critical Flow of Wet Steam through Chokes” (Chien, 1990) iterations to find the appropriate sized nozzle diameter for the steam quality. However the effect of steam quality will greatly impact the performance of the ICD. The properties of the steam highly depend on the inlet and outlet pressures. As the proposed design (for ICDs) calls for sub critical chokes, it is important to design for unchoked flow for all operating conditions. This calculation was done in a standalone spreadsheet. Please see Chein; for more information on the calculation.

Based on the base well, at 500 m³/d with an OD of 6.625”, for a steam quality of 95% the necessary choke diameters are in Table H-1 for a nozzle length of 19.8 mm.

<table>
<thead>
<tr>
<th>Table H-1 - Necessary Nozzle Diameter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diameter (mm)</td>
</tr>
<tr>
<td>--------------</td>
</tr>
<tr>
<td>5.7</td>
</tr>
</tbody>
</table>

Devices provided by service companies may not fit these ideal specifications due to material properties. Thus further simulation may be required to model the device flow behavior.
Appendix I  Additional case – Varying Height Reservoir

An additional case has been simulated for an increasing in height reservoir. The design parameters are found in Table I-1

<table>
<thead>
<tr>
<th>Table I-1 - Target rate for varying height reservoir</th>
</tr>
</thead>
<tbody>
<tr>
<td>Segment</td>
</tr>
<tr>
<td>Number of ICDs</td>
</tr>
<tr>
<td>Segment Height (m)</td>
</tr>
<tr>
<td>% Flow to each segment</td>
</tr>
<tr>
<td>Target Segment rate (QT=500) (CWE m3/d)</td>
</tr>
<tr>
<td>Flow through each ICD (CWE m3/d)</td>
</tr>
<tr>
<td>ΔP_{ICD} (kPa)</td>
</tr>
<tr>
<td>$a_{ICD}$</td>
</tr>
</tbody>
</table>

**Lower Height**  \( P_{wh} = 3620 \text{ kPa} \)

| Segment | 1 | 2 | 3 |
| Number of ICDs | 13 | 13 | 14 |
| Segment Height (m) | 4 | 10 | 16 |
| % Flow to each segment | 13 | 33 | 54 |
| Target Segment rate (QT=500) (CWE m3/d) | 62.5 | 166 | 271.5 |
| Flow through each ICD (CWE m3/d) | 4.8 | 13.1 | 18.9 |
| ΔP_{ICD} (kPa) | 330 | 240 | 200 |
| $a_{ICD}$ | 142 | 15 | 5.2 |

**Higher Height**  \( P_{wh} = 3635 \text{ kPa} \)

| Segment | 1 | 2 | 3 |
| Number of ICDs | 13 | 13 | 14 |
| Segment Height (m) | 4 | 10 | 16 |
| % Flow to each segment | 13 | 33 | 54 |
| Target Segment rate (QT=500) (CWE m3/d) | 62.5 | 166 | 271.5 |
| Flow through each ICD (CWE m3/d) | 4.8 | 13.1 | 18.9 |
| ΔP_{ICD} (kPa) | 330 | 240 | 200 |
| $a_{ICD}$ | 142 | 15 | 5.2 |

The flow rates along the length of the wellbore are shown in Figure I-1.

![Figure I-1](image-url)  
Figure I-1: Rate flux along the horizontal section for a varying height reservoir split into three segments. The target rates and strength \( a_{ICD} \) of each segment are found in Figure I-1. Segment 1 is the left segment, 2 the middle and 3 the right.
Appendix J References for Appendix


Wei, W. and Gates, I.D. 2010. On the Relationship between Completion Design, Reservoir Characteristics, and Steam Conformance Achieved in Steam-based Recovery Processes such as SAGD. SPE-129694-MS presented at SPE Improved Oil Recovery Symposium, Tulsa, Oklahoma, USA, 24-28 April 2010. 10.2118/129694-ms: