Brodgar Downhole Gauge Analysis with Deconvolution

By

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

September 2011
Declaration of Own Work

I declare that this thesis

‘Brodgar Downhole Gauge Analysis with Deconvolution’

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

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Brodgar Downhole Gauge Analysis with Deconvolution

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Abstract
Pressure transient analysis (PTA) has been performed to analyze data acquired from downhole pressure gauges in horizontal and vertical wells in Brodgar, a lean gas condensate reservoir. The main part of the analysis has been done on a horizontal production well, which has been in production for three years, thereby providing a wealth of pressure transient data for analysis. For this reason, deconvolution has been implemented in order to process that data in a way that more of the reservoir could be seen through PTA. The objective was to gain an understanding of water movement in the reservoir which caused water breakthrough in February 2011. Through a combination of conventional, deconvolution and numerical PTA, the aquifer boundary movement has been traced since production began in 2008, and the aquifer is currently 100 ft away from the well. The timing of this is in line with the field production data. In order for the production well data to be valid for deconvolution, the interference effects from the other production well had to be eliminated. Two approaches to eliminate the interference have been implemented in this work; one based on an analytical line source model and the other based on a numerical multi-well simulation model. The results of both methods are in agreement, thus confirming the robustness of the analysis.

Introduction
Pressure transient analysis is used to characterise field static and dynamic performance. It has been used to interpret pressure-rate data acquired from downhole pressure gauges (DPG) fitted to wells in Brodgar, which is a field that is partly owned by ConocoPhillips. Different well models and boundary conditions are investigated with the aim of determining whether reservoir properties are changing with time, and whether water encroachment can be identified from PTA. The core deliverable of the project is a consistent interpretation of Brodgar, and this is presented further down in the report.

Brodgar Field. Brodgar is a lean gas condensate field (CGR 55 bbl/MMscf) located 41 kilometers south-west of the Britannia platform in block 21/3a in the Central North Sea. The field was discovered in 1985 and has been produced by two subsea horizontal production wells since July 2008. The Brodgar field is in the Early Cretaceous Britannia Sandstone formation at a depth of 10,800 ft TVDSS and has an initial pressure / dew point pressure of 4960 psia. ConocoPhillips has a 75% equity in the field, and the rest belongs to Chevron.

The potential for water production in Brodgar has been a significant risk to booked reserves through the life of the field due to the 500 barrels of water per day (bwpd) volumetric handling capacity of the mono-ethylene glycol (MEG) reclamation unit. MEG is continually injected into the Brodgar manifold to inhibit formation of hydrates in the subsea pipeline, and is recovered through the MEG reclamation unit on the platform. Water breakthrough timing has been difficult to predict through the life of the field. It occurred in February 2011, and production had to be drastically reduced in order to minimize water production levels.
Pressure Transient Analysis.

Objective. This project provides an understanding of water breakthrough and reservoir properties in Brodgar using PTA of the DPG data available throughout the life of the field from the H1 production well. The idea is that PTA can provide an understanding of water movement through time in the reservoir, which would be used to QC the reservoir simulation models. In addition, it would provide insight into water movement in the reservoir, and better predict water breakthrough in the third horizontal production well, 21/03-H3, which is currently being planned for drilling in the 'western' sector of Brodgar.

Available Data. Figure 1 shows a map of Brodgar and the types of data available for PTA from each well. Those are also tabulated in Table 1. Figure 2 shows the pressure-rate history of each of the two production wells of Brodgar. Figure 3 is another map of the reservoir showing possible seismic fault locations.

<table>
<thead>
<tr>
<th>Year</th>
<th>Well</th>
<th>Data</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>1985</td>
<td>21/03a-4 (4-Well)</td>
<td>Exploration well (DST)</td>
<td>Two perforated intervals</td>
</tr>
<tr>
<td>2000</td>
<td>21/03a-7 (7-Well)</td>
<td>Appraisal well (DST)</td>
<td>Partial penetration</td>
</tr>
<tr>
<td>2005</td>
<td>21/03a-H1 and 21/03a-H2Y</td>
<td>Production well clean-up</td>
<td>73 hours long each</td>
</tr>
<tr>
<td>2008 – 2011</td>
<td>21/03a-H1</td>
<td>Production data</td>
<td>Three years of data</td>
</tr>
<tr>
<td>2008 – 2009</td>
<td>21/03a-H2Y</td>
<td>Production data</td>
<td>DPG failed in December 2009</td>
</tr>
</tbody>
</table>

Table 1: List of available data for pressure transient analysis.

The above listed datasets have been analysed, and the documentation further down presents the procedure followed, results obtained and conclusions made.
Deconvolution. Deconvolution is a mathematical formulation used to process pressure transient data. It converts pressure data from several flow periods with various production rates into a single unit rate drawdown. The drawdown has the duration of the entire pressure-rate history, which means that its late-time behaviour is considerably longer than that of any of the individual flow periods. This enables the deconvolved derivative to show boundaries to flow that are too far away to be seen on the derivative of any individual flow period. By having a permanent DPG fitted to a production well, years of pressure transient data could be made available for deconvolution, which would provide an increased radius of investigation. Deconvolution is central to the analysis presented in this work, as each of the datasets listed in Table 1 has been analysed both in the conventional manner and using deconvolution. Note that throughout this work, ‘derivative’ refers to the pressure derivative of Bourdet et al. (1983).

Literature Review

Deconvolution of pressure-rate history has been the subject of research by several authors during the last 40 years. The modern use of deconvolution to facilitate the analysis of pressure transient data began in 2001 with the introduction of a formulation based on the logarithm of the response function by von Schroeter et al. (2001). This formulation implemented deconvolution as a nonlinear total least squares problem. These authors also introduced a new error model that takes into account errors in both pressure and production rate data. These authors improved their method in von Schroeter et al. (2002) by incorporating the variable projection algorithm, which by then was standard for minimization of the separable error measure.

Levitan (2003) evaluated von Schroeter et al.’s algorithm for application to real test data. He found that the algorithm fails when applied to inconsistent data; which is the case for most real data, due to changing wellbore storage and rate-dependent skin. However, he suggested using the algorithm for single flow periods (of constant rate) for interpretation. He also suggested comparison of the deconvolved data of several flow periods in order to identify initial reservoir pressure.

Horizontal wells have seen widespread use since the early 1980s due to their high productivity in early-life (Ozkan 1999). Therefore, well test analysis has been extended to enable the interpretation of pressure transient behaviour of horizontal wells, which is different from a vertical well’s behaviour. The main difference is the fact that a horizontal well typically sees two flow stabilizations; radial flow in the vertical plane at early time and pseudo-radial flow in the areal (horizontal) plane at intermediate time. This phenomenon was first expressed analytically by Daviau et al. (1985). Kuchuk et al. (1990) showed the importance of analyzing the build-up after the first drawdown in horizontal wells, highlighting that pressure analysis without rate measurements is insufficient for horizontal well test analysis. Kuchuk et al. (1991) introduced the analysis of horizontal wells using the pressure derivative, where they identified the typical flow regimes. That same year, Malekzadeh and Tiab (1991) introduced dimensionless pressure and pressure derivative type curves for interference testing of horizontal wells with appropriate equations. Then, Ozkan (1999) gave a holistic methodology for interpreting horizontal well responses, and highlighted the strengths and weaknesses of every approach suggested in the previous literature. He also mentioned the benefits that a stable deconvolution algorithm could bring to the analysis of horizontal wells, which was before von Schroeter et al. published their deconvolution algorithm mentioned above.

Research Method: Pressure Transient Analysis

PTA makes use of pressure transient data to estimate certain well and reservoir properties (ex. Permeability, thickness, and flow boundaries). This data could be obtained from a dedicated well test (ex. DST) or from data acquired from a DPG over the producing life of the well. The results of any PTA come with a range of uncertainty on each of \( K_{\phi} h, K_{\phi} C, S \) and flow boundary distances (Azi et al. 2008). The aim of doing PTA on Brodgar’s data was to gain an insight into the reservoir’s properties and how they may have changed through time due to water movement in the reservoir, which eventually resulted in water breakthrough. This is important for two reasons:

- Improving the ability to forecast production from Brodgar.
- The insights could be useful for the monitoring of the future 21/3A-H3 production well.

Although data was already available on the permeability of Brodgar, \( K \), from core analysis (Figure 4), this was taken on discrete core plugs, which described small sections of the reservoir, whereas an estimate from PTA would provide a better understanding of the reservoir’s effective permeability. The uncertainty on \( h \) is quite low due to the availability of wireline log data. However, the importance of reservoir thickness comes into play when analysing the production data because it is important to find out if that is showing a reduction in \( h \) through time due to water encroachment, and if so by how much. As for the flow boundaries, these could correspond either to seismic faults, sub-seismic faults (not detected due to the poor resolution of the seismic survey) or any other form of boundary to flow. Seismic interpretations indicate the presence of faults within the vicinity of Brodgar’s production wells, as shown in Figure 3, although they are not believed to be fully sealing. There is uncertainty around the existence, location and degree of weakness of these faults. Flow boundaries can also result in pressure maintenance as opposed to depletion (which results from sealing boundaries). A constant pressure boundary could either be a gas cap or an aquifer. If the aquifer is weak and is moving slowly however, it can act as a sealing boundary by causing apparent depletion at its interface with the gas or oil. This is due to the rapid decrease in gas (or oil) relative permeability caused by the decrease in saturation at the interface.

Single-Phase Gas Pseudo-Pressure. Brodgar is a lean gas condensate field, with a CGR of 55 bbl/MMscf. None of the available pressure transient datasets exhibits composite behaviour. Therefore, it was deemed appropriate to analyse Brodgar as
a single-phase gas reservoir. The condensate flow rates, recorded in bbl/d, have been converted to Mscf/d and then added on to the gas flow rates to give total gas flow rates in Mscf/d. Due to compressibility effects, the pressure transient response of a real gas is not linear; thus it cannot be solved by analytical methods (Al-Hussainy et al. 1966). Therefore, the pressure \( P \) data is converted into pseudo-pressure \( m(P) \) in order to linearize the gas diffusivity equation so that it could be solved analytically. The conversion is done using the following integral:

\[
m(P) = 2 \int_{0}^{t} \frac{P}{\mu(P)z(P)} \, dP
\]

Where the reference pressure \( P_0 \) is an arbitrary constant, and is usually the atmospheric pressure. The pseudo-pressure has the unit of psia/cp. It should be noted that this transformation does not exactly reproduce an equivalent liquid pressure in the case of high change in compressibility. In such a case, like when there is significant pressure depletion due to long prior production, the uncertainty on the value of \( K \) obtained from PTA increases.

**Procedure.** In order to confirm that the PTA models created in this work gave correct interpretations of their respective well/reservoir systems, they have been verified to generate simulated data that matches the following:
- Build-up pseudo-pressure vs. time log-log plot
- Build-up pseudo-pressure derivative vs. time log-log plot
- Build-up pseudo-pressure vs. function of time semi-log plot
- Build-up(s) convolved pseudo-pressure vs. time log-log plot
- Build-up(s) deconvolved pseudo-pressure derivative vs. time log-log plot
- Build-up(s) convolved pseudo-pressure vs. function of time semi-log plot
- Entire pressure history

The steps followed in this work to perform PTA are outlined below:
- Determination of initial reservoir pressure \( P_i \)
- Conventional analysis of each individual build-up
- Deconvolution analysis of each individual build-up
- Deconvolution analysis of a combination of build-ups
- Numerical Analysis to finalize the estimates of distances to flow boundaries

**Well Models.** Two different well models have been used in the PTA interpretations of this project; horizontal and vertical – limited entry. The pressure transient behaviour of horizontal wells is considerably more unpredictable than that of vertical wells. This is because the response is very sensitive to the various assumptions that are made in the analysis of horizontal wells, including:
- Homogeneous horizontal formation of uniform thickness, \( h \)
- Effective production from the entire horizontal section of the well
- Well is a horizontal straight line
- Multi-phase flow behaviour has no effect on the characteristic features of horizontal well response

**Deconvolution.** A brief explanation of the deconvolution algorithm used is given in the following. During variable-rate testing in a linear system, wellbore pressure is given by the following integral:

\[
P(t) = P_i - \int_{0}^{t} q(\tau) \left( \frac{dP}{dr} \right) \, d\tau
\]

Where, \( q(t) \) is the well rate, \( P(t) \) is the well bottomhole pressure, \( P_i \) is the reservoir initial pressure, and \( P_d(t) \) is the rate-normalized pressure response to constant-rate production. The assumption here is that the reservoir is in equilibrium and the pressure is uniform throughout the reservoir. This is known as Duhamel’s integral. It is an expression of the principle of superposition resulting from the system being linear. Deconvolution reconstructs the constant-rate drawdown pressure response \( P_d(t) \) and the initial reservoir pressure \( P_i \) from \( P(t) \) and \( q(t) \) acquired during the test. von Schroeter et al.’s deconvolution algorithm does not solve for the constant rate pressure response \( P_d(t) \), but for the function:

\[
z(\sigma) = \ln \left[ \frac{dP_i(t)}{d\ln t} \right] - \ln \left[ \frac{dP_i(\sigma)}{d\sigma} \right]
\]

Where \( \sigma = \ln(t) \). This reduces the convolution equation (2) to:

\[
P(t) = P_i - \int_{0}^{\infty} q(t - \tau) e^{-\tau} \, d\tau
\]

Selection of \( z(\sigma) \) as a new solution variable ensures that \( dP_d(t)/d\ln t \) is positive.

In the presence of measurement errors, the unobserved pressure signal is given by \( \Delta P + \epsilon \), and the unobserved rate signal by \( q + \delta \). \( \epsilon \) is the signal representing the pressure measurement errors and \( \delta \) is that for rate measurement errors. These unobserved signals satisfy Duhamel’s principle:

\[
\Delta P + \epsilon = G(\cdot)(q + \delta)
\]

Where:
- \( z \) is a vector \((z_1, \ldots, z_n)\), which when multiplied by a fixed set of interpolants \((\psi_k, \ k = 1, \ldots, n)\) yields:
\[
z(\sigma) = \sum_{k=1}^{n} z_k \psi_k(\sigma)\]

- \( G(z) \) is the matrix of the set of equations which result from evaluating Equation (2) at times \( t = t_i \):
\[
\Delta P = G(z)\Psi \]

The aim when implementing deconvolution is to arrive at a result in which the vectors \( \epsilon \) and \( \delta \) are small and in which the response \( z \) is sufficiently smooth. The algorithm achieves that through the minimization of the term, \( E \), given below:
\[
E = \|\epsilon\|^2 + \nu \|\delta\|^2 + \lambda \|Dz - k\|^2
\]

Where \( \nu \) is a weight factor which takes into account the rate match and the pressure match, and \( \lambda \) is the weight factor which accounts for curvature (smoothness). The user manipulates these two parameters until he/she arrives at a deconvolved model data only matches DD1 and DD2. Full details of the deconvolution algorithm used in this work can be found in von Schroeter et al. (2001), von Schroeter et al. (2002) and Levitan (2003).

**Preliminary PTA Interpretations**

**21/A-4 DST:** Initially, prior to BU2 indicated on Figures 5 and 6, 20 ft of the well section exposed to the reservoir was perforated; between 11040 and 11060 ft MD. Then prior to BU3 another 20 ft, between 10973 and 10993 ft MD, were perforated. For this reason, the results from each build-up analysis are different. The permeability obtained is \( K_{S2} = 280 \) (from BU2) – 330 (from BU3) mD, which is a range close to the mean obtained from core analysis (Figure 4). The vertical anisotropy ratio has been found to be \( K_v/K_{S2} = 0.02 \) (BU3) - 0.08 (BU2), but due to the lack of early-time data there is uncertainty on this value. Moreover, the analysis shows a single sealing flow boundary somewhere between 670 (BU3) and 800 (BU2) ft away from the well. Figures 5 and 6 show the pressure – rate history of this DST. Figures 7 and 8 demonstrate how the model of BU3 matches both the conventional and convolved/deconvolved data of that build-up. Figures 9 and 10 show the same for the model of BU2. Figures 5 and 6 also show the match between the pressure history, convolved pressure history and model data for BU3 and BU2, respectively. As shown in Figures 5 and 6, due to more of the reservoir-exposed section being perforated during the second half of the DST, the well produced at a higher rate during DD3 than it did during DD2 even though the pressure was drawn down less than half as much during DD3. Therefore, BU3 model data only matches DD3 and DD4. In the same manner, BU2 model data only matches DD1 and DD2.

![Figure 5: BU3 model and convolved pressure data match measured pressure data (4-Well).](image1)

![Figure 6: BU2 model and convolved pressure data match measured pressure data (4-Well).](image2)

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1Personal communication with S. Trin (2011) France: KAPPA Engineering.
21/A-7 DST. Most of the well section exposed to the reservoir was perforated this time around; 88 out of 110 ft. A lower value has been obtained for permeability, with $K_H = 165$ mD and $K_V/K_H = 0.03$. $K_H$ is almost identical to the median from core analysis (Figure 4). Moreover, the availability of early-time data this time makes it possible to see a large degree of limited entry behaviour, which resulted from heterogeneity along the reservoir depth as most of the perforated interval was exposed to the low-$K$ sections. This meant that flow at early-time only came through the thin perforated high-$K$ interval. One model has been obtained this time to match the entire pressure history. Figures 11 - 13, 15 and 16 show the matches achieved between model data and measured data (conventional and convolved/deconvolved). The data in Figure 15 are a result of deconvolution of all BU4 data combined with BU1 late-time data. Figure 14 shows that deconvolution of BU1 failed, which is evidenced by the big mismatch between convolved and original pressure data. Note in Figures 11, 12 and 15 that there was changing wellbore storage (Hegeman et al. 1993) at early-time during BU4 as multi-phase flow turned into single-phase (gas) flow.

It has been possible through deconvolution to see an open rectangle sealing boundary system around the well. One of these boundaries has been seen at 700 ft, thereby indicating that it was possibly a continuation of the one seen by the 4-well, and confirming that the boundary system looked as shown in Figure 17. Note that this is certainly an idealization of what the boundaries would have looked like in reality. As Brodgar’s geology indicates that it is highly unlikely that it has any sealing faults, the best interpretation for the boundaries identified so far is that they were the reservoir’s limits at the time. Beyond these limits was a weak aquifer, the effect of which resembles that of a sealing flow boundary system on all derivatives in this work.
**Figure 13**: Model data matches BU1 pseudo-pressure and derivative data (7-Well).

**Figure 14**: Deconvolution of BU1 failed, which is evidenced by the mismatch between convolved and measured pressure (7-Well).

**Figure 15**: Model data matches convolved/deconvolved response, which is a result of deconvolution of BU4 data combined with BU1 late-time data (7-Well).

**Figure 16**: Model and convolved pressure data match measured pressure data (7-Well).

**Figure 17**: Interpretation of Brodgar based on analysis of the data from DSTs and clean-up periods.

**Table 2**: Model parameters for all interpretations of H1 production pressure build-up data (conventional and deconvolution analyses).

### H2Y Clean-up

The same value for $K_H$ (165 mD) has been found from analyzing this dataset as that from the 7-well DST. $K_v/K_H$ is 0.1 this time. However according to Kuchuk (1995), it is a big assumption to interpret a horizontal well pressure transient as being in a single-layer reservoir when the reality is that the reservoir is a multi-layer formation. This shows that the uncertainty on $K_v/K_H$ from this analysis is higher than the uncertainty on the 7-well DST value. Moreover, a sealing flow boundary is seen at 700 ft. As shown Figure 17, this is more likely to have corresponded to the north-eastern reservoir limit. Figures 18, 19 and 22 show the match between model and data. Note from Figure 18 that intermediate-time linear flow, characteristic of horizontal wells (Kuchuk et al. 1991), did not take place here or during H1 clean-up (Figure 20). This is evidenced by the absence of a ½ unit slope on the derivative in between the two stabilizations. The reason is that the condition for this linear flow to occur is that the length of the horizontal section should satisfy (Ozkan 1999):

$$L \geq \frac{100n}{K_v} \sqrt{K_H}$$

Note that for Brodgar, the right-hand side of the above equation is equal to 34,785 ft; clearly much greater than $L$ for both H2Y and H1. Because the above condition is not satisfied, 3D flow ensues instead.
**H1 Clean-up.** The same value for $K_H$ (165 mD) has been found from analyzing this dataset as that from the H2Y clean-up and the 7-well DST. $K_v/K_H$ has been found again to be 0.1. A sealing flow boundary has been seen at 1000 ft distance. Looking at Figure 17, it is most likely that this boundary corresponded to the south-western reservoir limit (H1 being slightly further away from that limit than 7-well was). Figures 20, 21 and 23 show the match between model and data.

**Elimination of Interference Effects in H1 Bottomhole Pressure**

Both production wells, H1 and H2Y, started production in July 2008. So from the onset, each well’s production has been causing interference and depletion in the bottomhole pressure of the other, as shown in Figure 24. This complicates PTA on the pressure data of these wells as the depletion in well bottom-hole pressure could be mistaken for depletion in the reservoir and misinterpreted as flow boundaries. Furthermore, interference makes deconvolution impossible with the current version of the algorithm, which does not incorporate Levitan’s multi-well extension (Levitan 2006). Therefore, the interference effect had to be eliminated in order to be able to make realistic interpretations of the available pressure transient data. Figure 25 shows that the two wells are close together, their centres being 2280 ft apart.
The DPG of H2Y well failed in December 2009 (Figure 2), whereas H1 well’s DPG is still functioning. Therefore H1 data has been chosen for analysis. The interference effects from the acquired pressure data of H1 have been eliminated by two different methods:


Note that in reality the interference effect would still be there, especially where H2Y was flowed while H1 was shut-in.

**Method I: Analytical Line Source Model (ALSM).** This method consisted of the following steps, (see Figure 26):

- Based on the reservoir boundaries identified in the 7-well DST interpretation, a line source model has been created from an interference test which combined the pressure of H1 (observation well) and the rates of H2Y (active well).
- The line source model has been used to generate a simulated pressure history.
- This has been subtracted from initial pressure \( P_i \) to obtain \( \Delta P \) data which were purely a result of interference.
- These \( \Delta P \) have been added to the original pressure history.

Figure 26: Elimination of interference effects in H1 pressure using analytical line source model (ALSM) method.

\( Pi \) was taken as the pre-production pressure observed on the data (4900 psia). \( K_H, h \) and \( \Phi \) were taken as those of the active well, H2Y (Guillonneau 2004). This method is based on the assumption that the effect of production from one horizontal well on the BHP of another follows a line source solution. Figure 27 compares data during BU1 (the first shut-in period post-production). H2Y production data (active well) is compared to ALSM data, which is assumed to be purely a result of interference from H2Y in H1. Figure 27 shows that the IARF stabilization of the active well does not line up with that of the line source model, which leads to the conclusion that the line source approximation is not accurate. That is probably due to the wells being relatively close together, as shown in Figure 25.

It is worth noting that the analytical line source solution does not take into account permeability anisotropy, which has been shown by Houali et al. (2005) to have a big impact on the behaviour of the pressure and pressure derivative, and would thus impact the results of interference test analysis.

Another essential input to the model was the well spacing. Saphir treats a horizontal observation well as an observation point, the location of which is at the centre of the well. This assumption on the location of the observation point is not an accurate one according to Al-Khamis et al. (2005). Moreover, the same paper states that it is only suitable to represent a horizontal observation well by an observation point if the wells are parallel and sufficiently far apart; \( \Delta y/L \) should be greater than 3, where \( \Delta y \) is the inter-well distance component perpendicular to \( L \) measured from the heels of the two wells. The reason for this latter condition is that if the wells are too close together, the geometries of the wells cannot be ignored due to elliptical flow around them. H1 and H2Y are not parallel and \( \Delta y/L \) is of negligible value, so it is certainly less than 3.
Based on the above discussion, there are four contributors to the uncertainty around the results of the ALSM method. The effects of these factors will be shown to be non-negligible further down in the text.

**Method II: Multi-Well Numerical Simulation Using a Voronoi Grid.** This method consisted of the steps below (also see Figure 28):

- A numerical model which incorporated the pressure response of H1 and the rate histories of both H1 and H2Y has been generated using the Saphir numerical multi-well simulator on a Voronoi grid. The only criterion for this model was that it produced a simulated pressure signal that matched the original pressure history of H1.
- Once this model had been identified, H2Y rates were removed and the model re-run as a single-well numerical simulation in order to produce another pressure signal.
- The difference between the two simulated pressure signals was calculated as ΔP and then added to the original pressure history.

Each well has been constructed as a horizontal straight line on the grid (shown in Figure 29), with horizontal section length \( L \) and vertical distance from reservoir bottom \( Z_w \) as inputs. The trajectories of the two wells along their horizontal lengths are very close, so it was assumed that they both shared the same axis in that direction. As mentioned earlier, the distance between the centres of the two wells is roughly 2280 ft (Figure 25). Note on Figure 29 that the boundary system used here was also an open rectangle of sealing flow boundaries, albeit with different distances from H1.

![Figure 28: Elimination of interference effects in H1 pressure using numerical multi-well simulation (NMWS) method.](image)

![Figure 29: Voronoi grid used for numerical simulation in order to eliminate interference effects in H1 BHP using NMWS. The grid includes an open rectangle boundary and both horizontal wells.](image)

![Figure 30: Comparison of pressure datasets resulting from two methods of interference removal and original pressure history.](image)

**Comparison I.** Figure 30 shows the results from Methods I and II, and clearly the two corrected signals do not match. Based on the discussion above regarding uncertainty around Method I (ALSM), the dataset from Method II (NMWS) is the one that is more accurate. Nevertheless, the analyses of both datasets are presented in the following section. Note that the measured rate data from H2Y only extends until end of March 2011, due to failure of the venturi for rate measurement during that time. Therefore, the elimination of interference beyond the end of the available rate data is less accurate.

**Interpretation of H1 Production Data**

**Conventional Analysis.** Figure 30 shows the five shut-in periods which have been analysed, and Figure 31 compares the data of four of those from the original H1 pressure dataset on a log-log plot. In order to QC the interference correction of both methods, the parameters from 7-well’s DST interpretation have been input to see if they generated a match with BU1 of both datasets, since very little was expected to have changed in the reservoir prior to and during this flow period. Figures 32 and 33
show the comparison. It can be seen that the intermediate-time and late-time data is matched reasonably well by the ALSM data, whereas the early-time data is not matched due to changes in the well. The NMWS data only matches at intermediate-time, indicating that this build-up has not been corrected properly using this method. The difference between the model and corrected data in both cases is a qualitative indicator of the residual effects of interference on H1’s BHP, which is still not fully eliminated by either method. Figures 34 and 35 show comparisons of BU2-BU5 from ALSM and NMWS, respectively.

Table 2 shows the parameter values used in all interpretations from this point onwards. It is clear from the pressure derivatives that all build-ups see only three boundaries, as shown in Figures 36-43. The late-time dips in BU2 and BU3 (Figures 36, 37, 40 and 41) are a result of interference when H2Y was flowed while H1 was still shut-in, an effect which is only partially corrected. Moreover, the derivative of BU4 (NMWS) has end-effects, as shown in Figure 42. The open rectangle systems were sufficient to match the derivatives, however pressure support had to be added to each build-up’s model in order to make up for interference and match the pseudo-pressure data. There is no evidence on either dataset however of the existence of a constant pressure boundary; otherwise there would not have been any depletion. Deconvolution analysis combined with numerical simulation below showed that manipulating the boundary geometry on the grid eliminated the need to add a constant pressure boundary in order to make up for depletion.

As mentioned earlier, the boundaries seen on the derivatives are interpreted as being the reservoir’s boundaries with a weak aquifer. Figures 38, 39, 42 and 43 show that the southern boundary (which could very well be the northern one instead) was at 200 ft away from the well during BU4 and then reached 100 ft during BU5. This is confirmed by both datasets and is inline with field production data, which indicated that water broke through in February 2011 (around the time of BU4).

The following important observations are made from the analyses of both datasets:

- No-flow boundaries (i.e. the aquifer) moved closer to the wells with time, but not at the same rate in all directions.
- The ‘South’ boundary was very close to the well in February 2011 when water broke through, and was 100 ft away in March 2011.
- Mobility did not change in the reservoir, hence there was no sign of:
  ○ Condensate banking.
  ○ Decrease in h; water only moved horizontally.
  ○ Water coning in multiple directions; although water coning must have taken place, numerous cones would have reduced gas and condensate saturations around the wellbore, thereby reducing their combined relative permeability and raising the IARF stabilization level at intermediate-times.

Figure 32: Quality check of both corrected-for-interference datasets against 7-Well DST model (log-log).

Figure 33: Quality check of both corrected-for-interference datasets against 7-Well DST model (semi-log).

Figure 34: Build-ups 2 – 5 overlaid (corrected using ALSM).

Figure 35: Build-ups 2 – 5 overlaid (corrected using NMWS).
Interference Effects Eliminated Using Analytical Line Source Model

Figure 36: BU2 data and model (ALSM).

Figure 37: BU3 data and model (ALSM).

Figure 38: BU4 data and model (ALSM).

Figure 39: BU5 data and model (ALSM).

Interference Effects Eliminated Using Numerical Multi-Well Simulation

Figure 40: BU2 data and model (NMWS).

Figure 41: BU3 data and model (NMWS).

Figure 42: BU4 data and model (NMWS).

Figure 43: BU5 data and model (NMWS).
Deconvolution Analysis. Moving on, each build-up from Figures 34 and 35 has been deconvolved individually at the same $P_i$ of 4900.65 psia and smoothing of 1.2. The results of deconvolution are shown in Figures 44-53. The findings of conventional analysis concerning mobility and the locations of the boundaries within the vicinity of the well during each build-up have been honoured by both convolved/deconvolved datasets. However, the late-time behaviour on the deconvolved derivatives was not honoured by the boundary distances obtained analytically through conventional analysis. The slope can be seen to decrease at late-times beyond those seen on the conventional data. This could not be pseudo-radial flow stabilization, assuming of course that the interference effects have been correctly eliminated by either of the two methods mentioned above. The reason is that infinite pseudo-radial flow at such late times would not make sense given the significant depletion evident on the pressure data (both corrected and uncorrected), the implications such an interpretation would have on the size of Brodgar, and aquifer encroachment (otherwise water would have not broken through). Therefore, this points to the semi-channel, formed by the ‘North’ and ‘South’ boundaries, having expanded towards the west (or north-west to be precise) away from the well and the ‘East’ boundary. In order to obtain results that would give a rough estimate of the evolution of the boundary system, the numerical Voronoi grid simulator has been used to generate simplified grid maps of Brodgar (shown with dimensions in Figures 46-53). Each grid map was used as part of a separate numerical simulation from which data that matched a build-up was generated. Thereby, each build-up was matched individually by a numerical model with a unique set of boundaries. The matches obtained are shown in Figures 46-53 (all dimensions in feet). The findings of deconvolution analysis, in addition to those mentioned above, are as follows:

- Wellbore storage and skin parameters used are the same for each numerical model as those resulting from its corresponding analytical model from conventional analysis. This is the reason for the poor matches at early-times.

- None of the deconvolved derivatives sees a fourth boundary; sealing or constant pressure. The radius of investigation of BU6 is 72,800 ft.

- The reservoir has not been drained equally in all directions, and is clearly larger towards the ‘west’ than it is where the two production wells have been drilled.

- The simulated data is very close to the convolved pressure at each build-up despite the absence of a constant pressure boundary (contrary to the conventional analysis above). This reveals that the reason for the need to add a constant pressure boundary in the conventional analysis was in fact due to the limitations of analytical pressure transient analysis when it comes to modelling relatively complex reservoir geometries. Certainly, optimization of the boundary system on the numerical grid would have resulted in a better match. This however would have only been necessary if sizing Brodgar through time was an aim of this project.

![Figure 44: Convolved/Deconvolved Build-ups 2 – 5 overlaid (corrected using ALSM).](image)

![Figure 45: Convolved/Deconvolved Build-ups 2 – 5 (corrected overlaid (corrected using NMWS).](image)

![Figure 46: BU2 convolved/deconvolved data and model (ALSM). Grid map is shown and dimensions are given in ft.](image)

![Figure 47: BU3 convolved/deconvolved data and model (ALSM). Grid map is shown and dimensions are given in ft.](image)
Comparison II. The shortcomings observed in the previous section of each method are explained:

Weaknesses of the NMWS Method:

- The data from NMWS is noisier than that of ALSM, as shown in Figure 32.
- BU1 from NMWS did not match the 7-Well DST model as well as BU1 from ALSM did.
- Although the same values of $P_i$ and smoothing have been used for the deconvolution of all the build-ups from both datasets, the resulting derivative of BU2 from NMWS is not in line with the others as shown in Figure 45. This certainly could have been corrected by increasing the smoothing for BU2 of NMWS, but the values of $P_i$ and smoothing have been kept the same for all build-ups for the sake of consistency.

Weaknesses of the ALSM Method (apart from the points discussed earlier):

- Boundaries during BU2 of ALSM were further away from those of 7-well DST compared to boundaries during BU2 of NMWS.
- Boundaries moved more quickly according to the ALSM method. The aquifer is expected to move slowly if it is to act as a sealing boundary.

Conclusions and Further Work
Pressure transient analysis (PTA) has been undertaken to interpret data acquired during production from Brodgar. Due to the interference between the field’s two horizontal production wells, the problem could not be tackled directly. Therefore, data acquired during the exploration, appraisal and pre-production stages of development have been analyzed first in order to get an understanding of the pressure transient behaviour without any interference. Then, two methods have been followed in order to eliminate the interference in the pressure history of one of the wells:
- Method I: Based on use of an analytical line source model which incorporated results obtained from analyses of data acquired prior to production (PTA and core analysis).
- Method II: Based on use of numerical multi-well simulation, which comprised a grid map with the two production wells and a flow boundary geometry surrounding them.

This was a vital step in order to facilitate the analysis of the production pressure data, and to make it valid for deconvolution. The results from both methods have been discussed, and although each had its qualities and weaknesses, they both pointed to an aquifer encroaching horizontally through time. Both analyses indicated that the aquifer was 100 ft away from the well in March 2011, which explains the advent of water breakthrough around that time. Moreover, no change of mobility has been seen on either corrected pressure transient, which indicates that:
- Water coning must have taken place locally (i.e. only one ‘cone’).
- Reservoir thickness has not changed, meaning that the aquifer has not moved vertically.
- There has been no condensate banking.

Deconvolution has made it possible to get a better insight into the movement of the aquifer within the reservoir by providing a larger scale view of the changes in reservoir/aquifer interface locations through time. This was because deconvolution provided a view of greater extent towards the north-west of the reservoir by increasing the radius of investigation of each deconvolved flow period. Moreover, numerical analysis of the deconvolved data enabled the identification of a relatively intricate sequence of boundary movement through time. It has been found that the reservoir was not drained evenly, and that the north-western sector is larger than the south-eastern sector where both production wells had been drilled.

The analytical line source approximation has been shown to be inaccurate, which is probably due to the two horizontal production wells being so close together. This was further evidenced by the mismatch between the two corrected pressure datasets, and by the results of analysing those datasets; the data corrected using Method II gave more realistic results. Method II is a clear winner out of the two, and a good means of eliminating interference effects in the absence of a software package that incorporates a multi-well deconvolution algorithm. A good alternative could be a method based on Method I, but which uses the correct source function for a horizontal well instead of a line source approximation. One advantage that Method II would retain over such a method is the ability to correct the interference without having to use additional datasets or go through an iterative process.

There are several steps that shall be taken as a follow-up to this work. First, a QC shall be done on the reservoir simulation model by checking that it reproduces the aquifer movement sequence obtained from PTA. Second, the same methodology followed in this work shall be implemented in order to analyze the August 2011 build-up data. This would provide a more up-to-date view of what has happened in the reservoir, which is particularly important given that production has been significantly reduced in 2011 in order to better manage water production. Finally, the lessons and methodology learnt from this work will be applied to the interpretation of the future infill well pressure transient data. This would improve the chances of successfully predicting water breakthrough from that well.

Nomenclature

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>ALSM</td>
<td>Analytical Line Source Model,</td>
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<tr>
<td>Bbl</td>
<td>Stock tank barrels,</td>
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<tr>
<td>BHP</td>
<td>Bottom-Hole Pressure</td>
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<tr>
<td>BU</td>
<td>Build-up,</td>
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<tr>
<td>Bwpd</td>
<td>Barrels of Water per Day,</td>
</tr>
<tr>
<td>C</td>
<td>Wellbore Storage (bbl/psi)</td>
</tr>
<tr>
<td>C&lt;sub&gt;f&lt;/sub&gt;</td>
<td>Final C (changing wellbore storage) (bbl/psi)</td>
</tr>
<tr>
<td>CGR</td>
<td>Condensate Gas Ratio (bbl/MMscf),</td>
</tr>
<tr>
<td>C&lt;sub&gt;i&lt;/sub&gt;</td>
<td>Initial C (changing wellbore storage) (bbl/psi)</td>
</tr>
<tr>
<td>cp</td>
<td>Centipoise,</td>
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<tr>
<td>DD</td>
<td>Drawdown</td>
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<tr>
<td>DPG</td>
<td>Downhole Pressure Gauge,</td>
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<tr>
<td>DST</td>
<td>Drill-Stem Test,</td>
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</table>
\( \Phi \) = Porosity (\%),
\( h \) = Formation thickness (ft),
hr = hour
H1 = Horizontal production well,
H2Y = Horizontal production well,
IARF = Infinite Acting Radial Flow
K = Permeability (mD),
\( K_h \) = Horizontal permeability (mD)
\( K_{sh}h \) = Permeability – thickness product (mD ft)
\( K_v/K_h \) = Ratio of vertical permeability to horizontal permeability (anisotropy ratio),
L = Length of well horizontal section (ft),
MD = Measured Depth
mD = milli-Darcy
MEG = Mono-Ethylene Glycol,
NMWS = Numerical Multi-Well Simulation,
\( \Delta P \) = Difference in pressure (psi),
\( P_i \) = Initial reservoir pressure (psia),
psi(a) = Pounds-force per Square Inch (Absolute)
PTA = Pressure Transient Analysis,
S = Skin (dimensionless),
Sclf/d = Standard Cubic Feet per Day
\( \Delta t \) = Time of wellbore storage change (hr)
TVDSS = True Vertical Depth Sub Sea
\( \Delta y \) = Inter-well distance component perpendicular to length (ft),
\( Z_w \) = Vertical distance from reservoir bottom (ft)

References
- Ecrin Saphir V4.12.04, Dynamic Flow Analysis
- Voronoi, G.: “Nouvelles applications des paramètres continus à la théorie des formes quadratiques,” Journal für die reine und angewandte Mathematik (1908) 134 198
## APPENDIX A: Critical Literature Review

### MILESTONES IN DECONVOLUTION AND GAS CONDENSATE PRESSURE TRANSIENT ANALYSIS

#### TABLE OF CONTENTS

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<tr>
<th>SPE Paper n°</th>
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<th>Title</th>
<th>Authors</th>
<th>Contribution</th>
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<tbody>
<tr>
<td>71574</td>
<td>2001</td>
<td>“Deconvolution of Well Test Data as a Nonlinear Total Least Squares Problem”</td>
<td>T. von Schroeter, F. Hollaender, A. C. Gringarten</td>
<td>These authors introduced a new method that reformulated deconvolution as a nonlinear Total Least Squares problem.</td>
</tr>
<tr>
<td>77688</td>
<td>2002</td>
<td>“Analysis of Well Test Data From Permanent Downhole Gauges by Deconvolution”</td>
<td>T. von Schroeter, F. Hollaender, A. C. Gringarten</td>
<td>Reported a number of improvements to the algorithm of SPE 71574, and derived error bounds for rate and response estimates in the presence of uncertainties in the data, for which the authors assumed simple Gaussian models.</td>
</tr>
<tr>
<td>84290</td>
<td>2003</td>
<td>“ Practical Application of Pressure-Rate Deconvolution to Analysis of Real Well Tests”</td>
<td>M. M. Levitan</td>
<td>Independent evaluation of the algorithm developed in SPE 71574 and 77688, which found that it works well on consistent sets of data. The author also proposed enhancements of the algorithm that allow it to be used reliably with real test data.</td>
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<tbody>
<tr>
<td>14251</td>
<td>1985</td>
<td>“Pressure Analysis for Horizontal Wells”</td>
<td>F. Daviau, G. Mouronval, G. Bourdarot, P. Curutchet</td>
<td>First to present the rule that a horizontal well typically sees two flow stabilizations.</td>
</tr>
<tr>
<td>18300</td>
<td>1990</td>
<td>“Pressure-Transient Analysis for Horizontal Wells”</td>
<td>F. J. Kuchuk, P. A. Goode, B. W. Brice, D. W. Sherrard, R. K. M. Thambynayagam</td>
<td>Provided a standard approach for analyzing horizontal well pressure data: analysis of the build-up following the first drawdown in the dataset.</td>
</tr>
<tr>
<td>22733</td>
<td>1991</td>
<td>“Interference Testing of Horizontal Wells”</td>
<td>D. Malikzadeh, D. Tiab</td>
<td>Introduced dimensionless pressure and pressure derivative type curves for interference testing of horizontal wells with appropriate equations.</td>
</tr>
<tr>
<td>52199</td>
<td>1999</td>
<td>“Analysis of Horizontal-Well Responses: Contemporary vs. Conventional”</td>
<td>E. Ozkan</td>
<td>Gave a holistic methodology for interpreting horizontal well responses, and highlighted the strengths and weaknesses of every approach suggested in the previous literature.</td>
</tr>
</tbody>
</table>
Title: Deconvolution of Well Test Data as a Nonlinear Total Least Squares Problem.

Author(s): T. von Schroeter, F. Hollaender, A. C. Gringarten

Contribution to understanding of Deconvolution for Pressure Transient Analysis
These authors introduced a new method that reformulated deconvolution as a nonlinear Total Least Squares problem.

Objective(s) of the paper:
- Find a good algorithm for the deconvolution of real pressure and flow rate data.

Methodology used:
- Duhamel’s principle which states that the pressure drop is the convolution of the flow rate q and the reservoir impulse response.
- Formulation for deconvolution based on the natural logarithm of the response function, which implicitly imposes a positive sign constraint.
- Error reduction model which takes relative weights of pressure and rate data in order to calculate the distance of the solution from the actual data.

Conclusions reached:
- Introduced a new method which reformulates the long-standing problem of deconvolution as a nonlinear total least squares problem.
- Eliminated the need for explicit sign constraints by solving for the natural logarithm of time.
- Introduced an error model which accounts for errors in both pressure and rate data.
- At this stage, this new method was valid for rate errors of up to 10%.
Title: Analysis of Well Test Data From Permanent Downhole Gauges by Deconvolution.

Author(s): T. von Schroeter, F. Hollaender, A. C. Gringarten

Contribution to understanding of Deconvolution for Pressure Transient Analysis

These authors improved their method in SPE 71574 by incorporating the variable projection algorithm, which is now standard for the minimization of the separable error measure.

Objective(s) of the paper:
- Improve the nonlinear total least squares algorithm.
- Derive error bounds for rate and response estimates in the presence of uncertainties in the data.
- Discuss practical aspects of application of the algorithm to interpret large reservoir examples.

Methodology used:
- Deconvolution for well test analysis.
- Derivation of analytic expressions for the expected bias vector and covariance matrix of the estimated parameter set based on simple Gaussian models for the measurement of errors in pressure and rate signals.
- Regularization of deconvolved data by imposing a penalty on curvature, making that another parameter in the error function alongside pressure and rate.

Conclusions reached:
- The user can now control the degree of smoothness while avoiding the flattening of slopes associated with derivative regularization.
- The method gives estimates of bias and confidence intervals of the parameters.
- Unlike multi-rate derivative analysis, deconvolution does not suffer from any bias due to implicit model assumptions.
- The method has no restrictions in terms of choice of pressure window.
- The method handles measurement error in a more sensible way.
- An issue is still unresolved. There needs to be less subjective criteria for the selection of error weight and regularization parameter.
SPE 84290 (2003)

Title: Practical Application of Pressure-Rate Deconvolution to Analysis of Real Well Tests.

Author(s): M. M. Levitan

Contribution to understanding of Deconvolution for Pressure Transient Analysis
Completed an independent evaluation of the algorithm developed in SPE 71574 and 77688, which found that it works well on consistent sets of data. The author also proposed enhancements of the algorithm that allow it to be used reliably with real test data.

Objective(s) of the paper:
- Describe the enhancements of the deconvolution algorithm that allow it to be used reliably with real test data.
- Demonstrate application of the pressure-rate deconvolution analysis to several real test examples.
- Discuss practical aspects of application of the algorithm to interpret large reservoir examples.

Methodology used:
- Pressure-rate deconvolution.
- Encoding of the solution: natural logarithm of time.
- Regularization by curvature.
- Unconstrained nonlinear total least squares formulation:
  - An algorithm for unconstrained minimization.
  - Use of an objective function for least square minimization.

Conclusions reached:
- The algorithm fails when applied to inconsistent data; which is the case for most real data, due to changing wellbore storage and rate-dependent skin.
- Recommended using the algorithm for single flow periods (of constant rate) for interpretation.
- Introduced the method of comparing the deconvolved data of several flow periods in order to identify initial pressure and correct inconsistent rate data. The method handles measurement error in a more sensible way.
- An issue is still unresolved. There needs to be less subjective criteria for the selection of error weight and regularization parameter.
- The algorithm is capable of minimizing rate errors of up to an order of magnitude and initial pressure errors of hundreds of psi, thereby converging to the correct solution.
- The algorithm is sensitive to the number of model parameters, therefore, they need to be tailored to the test data being deconvolved.

Comments:
Levitan’s implementation differed from that of Schroeter et al. in the use of an algorithm for unconstrained minimization, and in the definition of the objective function and its parameters for least square minimization.
Title: Pressure Analysis for Horizontal Wells.

Author(s): F. Daviau, G. Mouronval, G. Bourdarot, P. Curutchet

Contribution to understanding of Pressure Transient Analysis of Horizontal Wells

These authors were the first to characterize horizontal well pressure transient behaviour. They established that a horizontal well typically sees two flow stabilizations.

Objective(s) of the paper:

- Develop analytical solutions using semi-log and log-log analysis to aid horizontal well test design and interpretation.
- Provide a way to decide whether a test has to be made.
- Provide a way to optimize test time.

Methodology used:

- An analytical solution which relates to the transient behaviour of a well with no wellbore storage or skin, and with uniform flow.
- An analytical solution which incorporates wellbore storage and skin, the effect of reservoir boundaries.

Conclusions reached:

- Developed an analytical model for horizontal well test design and interpretation.
- Identified two flow regimes: vertical radial flow and horizontal pseudo-radial flow.
- Provided means to determine the start and end times of each flow regime.
Title: Pressure-Transient Analysis for Horizontal Wells.


Contribution to understanding of Pressure Transient Analysis of Horizontal Wells
These authors provided a standard approach for analyzing horizontal well pressure data: analysis of the build-up following the first drawdown in the dataset.

Objective(s) of the paper:
- Provide a method for the interpretation of well-test data from horizontal wells.

Methodology used:
- An analytical solution for a horizontal well in a reservoir with a constant pressure boundary and without.
- Validation against synthetic and field data.
- Deconvolution of measured pressure (downhole) and pressure derivative using flow rate data.

Conclusions reached:
- The measurement of downhole flow rate is crucial for system identification as well as parameter estimation, especially in the presence of a constant pressure boundary and/or wellbore storage.
- Drawdown and build-up data tend to provide similar reservoir information at early times. They may compliment each other however when their late-times are analyzed.
- A drawdown test followed by a build-up test will produce satisfactory results for the estimation of reservoir parameters for horizontal wells if downhole flow-rate and pressure are measured.
Title: Pressure-Transient Behaviour of Horizontal Wells With and Without Gas Cap or Aquifer.

Author(s): F. J. Kuchuk, P. A. Goode, D. J. Wilkinson R. K. M. Thambynayagam

Contribution to understanding of Pressure Transient Analysis of Horizontal Wells
These authors introduced the analysis of horizontal wells using the pressure derivative.

Objective(s) of the paper:
- To extend the work of previous authors to obtain new analytic solutions for horizontal wells with and without the effects of a gas cap or aquifer.

Methodology used:
- Analytic solutions are presented in real time and as Laplace transforms bounded by the top and bottom by horizontal planes.
- Solutions based on the uniform flux line source solution with pressure averaging technique to approximate the infinite conductivity solution.
- Use of the correct value for equivalent wellbore radius for an anisotropic formation, which would guarantee that elliptical flow effects near the well are treated correctly at late times.

Conclusions reached:
- Pressure averaging along the well length is better than using an equivalent pressure point.
- Identified the correct equivalent wellbore radius to be used in the case of an anisotropic formation.
- Observed that the flow regime equivalent to infinite acting radial flow in a vertical well can be seen on a horizontal well, but in many cases does not develop.
- Laplace domain form of solutions produced in this work can be used to obtain solutions that include wellbore storage and skin effects.
- It is recommended to use non-linear least squares estimation methods to analyze horizontal well test data.
Title: Interference Testing of Horizontal Wells.

Author(s): D. Malikzadeh, D. Tiab

Contribution to understanding of Pressure Transient Analysis of Horizontal Wells

These authors introduced dimensionless pressure and pressure derivative type curves for interference testing of horizontal wells with appropriate equations.

Objective(s) of the paper:

- Solve the problem of interference testing of horizontal-to-horizontal and horizontal-to-vertical wells.
- Produce type curves with equations that enable the calculation of transmissibility and wellbore storage.

Methodology used:

- Instantaneous source functions together with the Newman product method.

Conclusions reached:

- The dimensionless pressure and dimensionless pressure derivative type curves for interference testing of horizontal wells reveal the magnitude of the pressure drop and time rate of change of pressure for various dimensionless distances of an observation well from active horizontal wells.
- Used a dimensionless function of reservoir height and horizontal well half-length in order to calculate vertical permeability.
Title: Analysis of Horizontal-Well Responses: Contemporary vs. Conventional.

Author(s): E. Ozkan

Contribution to understanding of Pressure Transient Analysis of Horizontal Wells
This author gave a holistic methodology for interpreting horizontal well responses, and highlighted the strengths and weaknesses of every approach suggested in the previous literature.

Objective(s) of the paper:
- Understand When should contemporary models be used instead of conventional, simplified models.
- Quantify the error made by using the conventional models.

Methodology used:
- Dimensionless pressure, time and distance formulations in order to infer well and reservoir characteristics through simple computations.
- Contemporary analytic equations that quantify more complex parameters of horizontal wells.

Conclusions reached:
- Provided discussions and results for use as guidelines to decide on the use of contemporary analysis procedures on horizontal wells.
- It is difficult to detect the unconventional features of horizontal wells on transient pressure responses because they are usually masked by the wellbore-storage effects and the stabilized flow period do not reveal any specific information.
- Conventional type-curve matching and straight-line analysis can yield considerable errors in cases of long, high-flow rate horizontal wells and/or non-uniform skin affect.
- The equivalent well length concept cannot be used for the analysis of selectively completed or multi-lateral well responses.
- The best approach would be to begin with an attempt to uncover the simple underlying response of a horizontal well by applying advanced convolution/deconvolution techniques.
APPENDIX B: Brodgar PVT Data Used for Single-Phase Gas Pseudo-Pressure Transform

H2Y-020R2  1093A  Tuned*11,EOS= PR78

PVT table created with PVTsim software to replicate experimental data.

Viscosity Correlation: Lorenz-Bray-Clark

Properties: Average of gas and condensate

Temperature = 240.0 °F

<table>
<thead>
<tr>
<th>Pressure (psi)</th>
<th>Viscosity (cP)</th>
<th>Z-factor</th>
<th>Cg (1/psi)</th>
</tr>
</thead>
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<tr>
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<td>1.24E+00</td>
<td>7.15E-05</td>
</tr>
</tbody>
</table>

Table B-1: PVT data used to transform pressure into gas pseudo-pressure.
Brodgar Field: well 21/03a-4

- Brodgar Field discovery well
- Drilled by Sovereign Oil & Gas in 1985
- 128’ TVT HC column
- 558’ core cut (555.5’ recovered)
- 2 x DST, fluid samples & pressures
- Net to Gross 97.6%
- Average Porosity 20.7%
- Average Sg 76.3%
- -11000’ TVDSS GOC
- -11013’ TVDSS OWC

Figure C-1: 4-Well Data.

Figure C-2: Rate history of 4-Well DST indicating stages of completion.
APPENDIX D: Additional Information on 21/03a-7 Appraisal Well

Figure D-1: 7-Well Data.
APPENDIX E: Models Used at Interference Removal Stage

This section lists the parameters of the two models used to generate the simulated pressure data from which $\Delta P$ was calculated and then added to the original pressure history to eliminate the effects of interference. Table E-1 lists the parameters of the analytical line source model and Table E-2 lists the parameters of the numerical multi-well model.

<table>
<thead>
<tr>
<th>Analytical Line Source Model Parameters</th>
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</tr>
<tr>
<td>$\Phi$</td>
</tr>
<tr>
<td>$h$</td>
</tr>
<tr>
<td>$K_h$</td>
</tr>
<tr>
<td>$K_p \cdot h$</td>
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<tr>
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</tr>
<tr>
<td>$d_{East}$</td>
</tr>
<tr>
<td>$d_{North}$</td>
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</table>

Table E-1: Analytical line source model parameters.

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<th>Multi-Well Numerical Model Parameters</th>
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<td>Input Data</td>
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<tr>
<td>Well Model</td>
</tr>
<tr>
<td>Wellbore</td>
</tr>
<tr>
<td>$r_w$</td>
</tr>
<tr>
<td>$L$</td>
</tr>
<tr>
<td>$Z_W$</td>
</tr>
<tr>
<td>$C$</td>
</tr>
<tr>
<td>$C_i/C_f$</td>
</tr>
<tr>
<td>$\Delta t$</td>
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<td>$S_{drainage}$</td>
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<td>$S_{total}$</td>
</tr>
<tr>
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<tr>
<td>$h$</td>
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<tr>
<td>$K_p \cdot h$</td>
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<tr>
<td>$K_v/K_h$</td>
</tr>
<tr>
<td>$\Phi$</td>
</tr>
<tr>
<td>$d_{South}$</td>
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<tr>
<td>$d_{East}$</td>
</tr>
<tr>
<td>$d_{North}$</td>
</tr>
</tbody>
</table>

Table E-2: Numerical Multi-Well Model Parameters.