IMPERIAL COLLEGE LONDON

Department of Earth Science and Engineering

Centre for Petroleum Studies

Assessment and Evaluation of Sand Control Methods for a North Sea Field

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 *Assessment and Evaluation of Sand Control Methods for a North Sea Field* 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.

Signature:..

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Robert Zimmerman, Imperial College

CONFIDENTIALITY AGREEMENT

In accordance with the data confidentiality agreement, the actual field and well names are treated as confidential. For the purpose of reporting, the field would be referred to as “Case Study”, the reservoirs as “Sand 1 and Sand 2” and the wells as “I1 and I2” for Water Injectors in Sand 1 and Sand 2, respectively.

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Assessment and Evaluation of Sand Control Methods for a North Sea Field

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Abstract

It is not uncommon for wells to require sand control, with thousands of them worldwide having been fitted with this equipment. To do so, service companies and sand control experts have over the years developed a range of guidelines, along with published and proprietary sand control selection methodologies. Unfortunately, many of the methodologies highlight a range of design criteria that are specific or complex; resulting in sand control selection being too time-consuming or difficult. The industry knows that there is no 'silver bullet' in choosing a sand control method. Consequently, a study has been conducted with the purpose of explaining a new sand control selection methodology that is concise and simple to understand. Furthermore, every sand control method can be assessed and evaluated as long as performance, reliability and cost are safely and economically justified.

Guiding the engineer to the most appropriate sand control technique, the study consolidates best practice from many published methodologies, and integrates them with the operator's sand management guidelines. Consisting of two flowcharts that end with a sand control equipment, the methodology also supplements each technical choice with a sand control selection table. This is where risks and concerns are outlined, assuming that the engineer has chosen the sand control resulting from the flowcharts.

Establishing a sand control selection is required in a North Sea field for its proposed water injectors. The water injectors are planned for injection under both matrix and fracture regimes into two reservoirs; called here Sand 1 and Sand 2. Sand in these reservoirs will fail as a result of fracture injection, and the produced sand may backflow into the wellbore once the well is shut-in. Using the new methodology, openhole premium-type Stand Alone Screen (SAS) is recommended for both reservoirs. Naturally, the flowchart's recommendation of premium-type SAS raises concerns, and is outlined in the sand control selection table. It is found that formation heterogeneity in both Sands 1 and 2 may dampen the performance of the premium-type SAS injectors. Using the methodology again, the flowchart also suggests the use of blank pipes and packers to isolate the impermeable shale sections. Inflow control valves are sized and positioned in the completions to counteract the non-uniform water flux caused by large permeability variation.

Now that a sand control is conceptually selected for the water injectors, the engineer can easily compare the recommended sand control with other techniques; as part of the overall selection process. Ultimately, this recommendation validates the use of the new methodology for future sand control selections.

Introduction

For over seventy years, the oil and gas industry has continually developed and used sand control completions in reservoirs to control sand production. This technology has played a pivotal role, and will continue to do so, as well demands are more challenging and performance expectations are greater. With high operating and well intervention costs, the impact of sand production cannot be ignored. The effect of formation sand in a well may lead to loss of integrity, and consequently cause the wellbore to collapse. It is absolutely crucial for the industry to manage sand actively.

Design and selection criteria for sand control methods vary among operators and location. Choice is influenced by local experience, case studies and service company recommendations. To date, several design methodologies have been published. For instance, Price-Smith *et al.* (2003) and Farrow *et al.* (2004) have published guidelines and selection matrices that have been widely used by the industry.

The main objective of this paper is to present a simple and easy to understand sand control selection methodology. The intention is not to reinvent the wheel, but to improve on existing sand control selections. The proposed methodology is built by consolidating the operator's sand management guidelines with relevant published papers. Consolidation is then integrated into a new methodology based on technical experience, laboratory testing and field case studies. The methodology is separated into two sections – flowcharts, and a 'traffic light' design matrix. These flowcharts are subdivided into parts A and B. Flowchart A is used as a 'first pass' selection criterion. It is used to guide the engineer to the most appropriate sand control option. Flowchart B focuses on the 'screen and gravel size' selection, and should be used in conjunction with Flowchart A. Then, 'traffic light' design matrix is used as further guidance once a sand control technique has been selected from the flowcharts.

The ‘traffic light’ concept (ranked by colour) refers to the effectiveness of the selected sand control technique in managing sand under a variety of wellbore and reservoir conditions. It is important to note that flowcharts and the ‘traffic light’ design matrix are merely guidelines for the engineer. The engineer is advised to use technical experience, rationality and in-house/service sand control experts as part of the overall selection process. Further explanation of the new methodology will be discussed later in this paper.

Study of rock mechanics and sand production prediction are important criteria in determining the most appropriate sand control. However, due to the limited size imposed on this paper, these topics will only be discussed briefly; focusing on how and why the sand may fail.

The second objective of this paper is to assess and evaluate suitable sand control methods for water injectors. These water injectors are part of a Field Development Plan (FDP) and have yet to be completed. The FDP is targeting oil accumulation in two sandstone reservoirs. Base case development is to drill a number of water injectors with a reservoir trajectory that will give optimum connectivity between the wellbore and formation. Injection of water into the reservoir will have a design capacity that is able to accommodate both matrix and formation fracture injection pressures. This is to ensure injectivity is not lost over time due to formation plugging. Water injection for this field is critical, and has three objectives. Firstly, to dispose produced water back into the reservoir. Secondly, to optimise sweep efficiency to improve oil recovery; and thirdly to ensure reservoir pressure is maintained. For wellbore stability, pressure maintenance of the reservoir is important to prevent compaction/subsidence of the formation and sand production.

Sand control is required to counter sand failure caused by production and operational issues. These issues can lead to several failure mechanisms. The failure mechanisms are water hammer, well backflow, reservoir cross flow and erosion (Santarelli *et al.*, 2000). These effects, if not accounted for, will cause a significant drop in injectivity over time. Inflow control technology will be modelled using NETool^{TM} as part of the selection to ensure uniform injectivity across all intervals.

In this case study, the sand control equipment is selected based on the outcome of flowcharts A and B. The ‘traffic light’ design matrix is then used to highlight the concerns and risks associated with the chosen sand control method. As long as the concerns and risks are accounted for, recommending the sand control based on the methodology can easily be justified. The outcome of this new methodology is an attempt to improve the selection consistency across the industry.

Methodology: Sand Control Selection

The proposed methodology for sand control concept selection using flowcharts is illustrated in Figures 1 and 2. The workflow in these illustrations focuses more on sand control for openhole completions. Sand control for cased hole completion is also outlined in Flowchart A. The flowcharts are supplemented by a sand control selection table highlighting risks and concerns of each technique-presented in Table D-1 to D-4 in Appendix D.

Flowchart A – ‘First Pass’ Selection Criteria

Flowchart A is an identification process to guide the engineer to the most appropriate sand control option. The start of this flowchart assumes that sand production will occur and sand control is required. The decision for an openhole or cased hole completion depends on rock geomechanics, wellbore stability and reservoir strategy. An openhole completion is favoured where high production rates are required and if the formation intervals are allowed to commingle. It is not a recommended completion if wellbore stability is poor and a large amount of fine sand is present. Fines are produced from the formation matrix as a result of increased stress and fluid movement. Cased hole completion is an alternative to openhole. It gives stability to wellbore integrity and provides isolation for productive intervals from unwanted gas and water. Most importantly, cased hole completion allows selective and oriented perforating that can delay or eliminate sand production.

Assuming openhole completion is defined, the next design criterion is the sand size analysis. This analysis is based on the methodology proposed by Tiffin *et al.* (1998). The study is used as a screening process in Flowchart A and further evaluated in Flowchart B. For example, if the formation has uniformity coefficients (D40/D90) of <5, D10 grain sizes >175μm, and mobile fines of less than 5%, the methodology recommends Standalone Screen (SAS) or Expandable Sand Screen (ESS).

After the study of sand size analysis, the presence and condition of shale in the formation must be studied. If a large slab of shale (greater than 30 ft) is present and unstable, it will require isolation. To achieve this, openhole packers and blank pipes are used across these sections. This is to prevent weakened shale from producing fines that can be detrimental to the sand control. Additionally, openhole packers can reduce annular flow and shut-off unwanted water or gas formations.

A large variation in reservoir permeability will require the use of inflow control technology in conjunction with sand control. Inflow Control Devices (ICD) or Inflow Control Valves (ICV) can control the amount of liquid flow and provide a more uniform distribution profile between the wellbore and reservoir zones. Controlling the flow will also reduce the annular flow velocity, preventing the formation of ‘hot spots’ that is a concern for sand control screen. The use of ICD is more applicable for horizontal wells to counteract the ‘heel-to-toe’ effect (Khalil *et al.* 2010). The ‘heel-to-toe’ effect causes a higher influx of liquid at the heel of the horizontal completion. To summarise, not accounting for permeability heterogeneity in the selection process may lead to water or gas breakthrough at an early stage of recovery.

ESS is recommended for reservoirs with similar permeability or when zonal isolation is not required. The advantage of using ESS is that it provides a larger inflow area and reduces pressure loss across the completion. It also eliminates annular flow between the screen annulus and wellbore. However, ESS is not recommended if the formation contains reactive shale.

Unstable shale can lead to breakouts or clay swelling, thus complicating its installation and use. This is because ESS has lower material strength than a conventional SAS.

If D40/D90>5, D10<175μm and mobile fines are greater than 5%, Openhole Gravel Packing (OHGP) is recommended instead. Two types of OHGP are commonly used – Slurry Pack with Alternate Path and Water Pack; shown in Flowchart A. Water Pack can be applied for low and high deviated wells. The technique uses a non-damaging brine to transport, circulate and pack low concentrations of gravel into the annulus between the screen and the wellbore. For wells with reservoir trajectory below 65^o, Flowchart A recommends Low Angle Water Pack (LAWP). This technique relies on gravity and flow rate to transport the gravel. Due to a low viscosity and density of the water carrier fluid, it cannot transport the gravel efficiently. LAWP will first transport the gravel to the bottom of the well and then pack the annular space from bottom to top. High Angle Water Pack (HAWP) is recommended for wells with reservoir trajectory above 65^o and the gravel-packing technique is called the Alpha/Beta design. As gravel slurry enters the screen via the openhole annulus, it settles and forms a dune (Tolan *et al.* 2009) at the heel of the horizontal well section. This is called the alpha wave. As more gravel is pumped, the alpha wave progresses from the heel to the toe of the horizontal well, overcoming the dune and depositing gravel on the backside of the openhole well. Once the alpha wave reaches the toe-end of the well, the beta wave starts to circulate backwards towards the heel, packing the open space on the topside of the horizontal well section. Circulating HAWP is not recommended if the formation shale is sensitive to brine. This is because the reaction between shale and brine can cause clay swelling and the shale may become unstable. Consequently, shale will collapse and obstruct the wellbore. This blockage will only allow the alpha wave to pack the completion interval from the obstruction back to the top of the screen. As beta wave propagates back towards the heel of the well, the blockage could cause friction pressure to increase due to fluid being continuously pumped over a lengthy distance. This can cause fluid losses (leak-offs) to the formation, preventing an effective placement of gravel. The HAWP technique is therefore only recommended for short openhole intervals (typically less than 1000 ft).

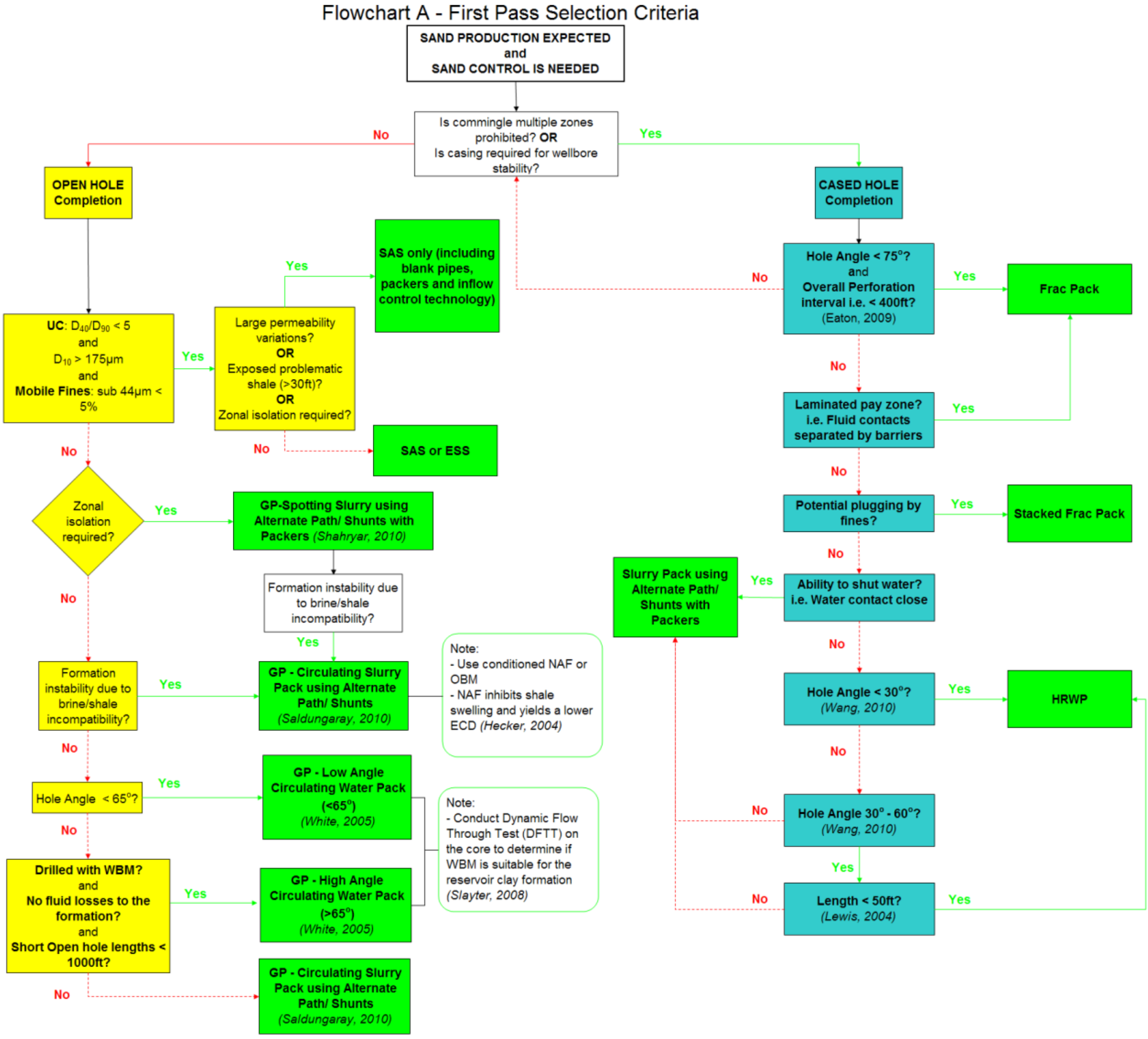

Figure 1: Flowchart A is used as 'First Pass Selection Criteria' for both openhole and cased hole wells.

Slurry Pack is another OHGP technique that uses a more viscous carrier fluid than the carrier fluid used for water pack. It stabilises the formation while ensuring well productivity is not compromised. The technique is suitable for formations with brine-sensitive shale, low fracture gradients (i.e. high fluid losses) and large variations in permeability. In other words, it is suitable for well conditions when LAWP or HAWP are not recommended. Slurry pack uses alternate path or nozzle-type shunt tubes to circulate the slurry down the openhole via the screen annulus; packing it from the toe and back to the heel of the horizontal well section. When a bridge forms in the annulus as a result of high leak-offs, the annulus packs only from the formed bridge back to the top of the screen. As the sand covers the top of the screen, diverting the slurry via the shunt tubes instead creates sufficient pressure. The slurry exits the shunt tubes below the formed bridge and packs any remaining voids in the screen annulus. Circulating slurry is recommended for long openhole intervals (>1000 ft).

Flowchart B – 'Screen and Gravel Size' Selection Criteria.

The proposed flowchart is illustrated in Figure 2. This section of the methodology analyses the sampling, grain sizing and fines identification of formation sand. The analysis requires samples that accurately define the formation, and full core sampling is the best method to achieve this. Sidewall core sampling is another source that is also acceptable. It is important to use Flowchart B to compare results with the outcome sand control selection from Flowchart A.

Rock mineralogy study is required to identify clay and fines, which can exist in the sandstone matrix and in the shale. Should the need arise, Optical Microscopy (OM) can be used to identify the presence of clay and fines while X-Ray Diffraction (XRD) and Scanning Electron Microscope (SEM) are other techniques that can assess the mobility and swelling of clay in a formation. Further work can be conducted using the Cation Exchange Capacity (CEC) (Slayter *et al.* 2008). This laboratory technique measures the reactivity of shale. Understanding clay swelling will enable the engineer to foresee risks and concerns when evaluating various sand control options. This study will also assist the engineer in selecting a suitable drilling mud that is compatible to both the formation and sand control completion. For example, the presence of unstable shale raises concerns if LAWP/HAWP or ESS is recommended. The concerns for various sand control techniques are highlighted in Table D1 to D4 (Appendix D).

The next step in Flowchart B is sand size analysis. This section of the methodology recommends the use of Dry Sieve Analysis (DSA) and Laser Particle Size Analysis (LPSA) to evaluate Particle Size Distribution (PSD). An example of a PSD study is illustrated on a semi-log plot; shown in Figure D-1 (Appendix D). The example in Figure D-1 shows 40% of the sand is coarser than D40 (247 μm) and 90% is coarser than D90 (94 μm). The D50 (214 μm) is used to represent the median grain size in the PSD study (Saucier *et al.* 1974). However, D50 is not applied in the flowchart as it is proven insensitive to the degree of sorting (Xiang *et al.*, 2003). This is because formation sands can have identical grain size but different size distributions. The D10 (Coberly *et al.* 1937) is used as a criterion instead for formation grain size. It is also used to design sand screen opening and gravel sizing. The smallest standalone screen opening is 125 μm but to date, 75 μm is now available (Franklin et al. 2011). Conventionally, if D10 <175 μm, the methodology does not recommend SAS or ESS.

Sorting is a measurement of uniformity. It is quantified in terms of the Uniformity (Uc) and Sorting (Sc) coefficients defined as D40/D90 and D10/D95, respectively. The former is defined by Schwartz *et al.* (1969), and the latter by Tiffin *et al.* (1998). Schwartz *et al.* (1969) classified four Uc categories: [Uc < 3: uniform], [3 < Uc < 5: moderately uniform], [5 < Uc < 10: non-uniform] and [Uc > 10: extremely non-uniform]. For 0<Uc<5, SAS is favourable. For Uc>5, OHGP is recommended.

DSA is limited to a minimum of 44μm (325-mesh) grain size. Therefore, sand particles with a diameter less than 44 μm are defined as "mobile fines" (Byrne *et al.* 2008). Mobile fines tend to stick to the larger grains or pass through the 325-mesh during DSA. Field experience and lab testing shows fines exceeding 5% have a tendency to cause screen plugging. LPSA can measure sand particles below 44μm and reflects the finer end of the PSD more accurately. Use both DSA and LPSA techniques to conduct PSD study. If the results of both techniques are incomparable, use DSA for sand control design. SAS is recommended for formation sample with fines less than 5%. For fines between 5-10%, OHGP should be used. If the fines are above 10%, increase the contact between the wellbore and formation (Tiffin *et al.* 1998).

Sand Control Selection Table.

Flowcharts A and B are supplemented by a sand control selection table. The table highlights design requirements and concerns for each sand control technique. These factors are illustrated in Tables D-1 to D-4 (Appendix D) and use a traffic light design matrix. The matrix system is presented based on colour and each colour refers to the effectiveness of a sand control technique in managing wellbore, reservoir and operational risks. The traffic light rating is based on the following: Green = preferred, yellow = acceptable, orange = use with caution and red = not recommended. This concept is similar to the methodology published by Farrow *et al.* (2004). The difference with the proposed methodology compared to Farrow *et al.* is the table is referred to after a sand control equipment is selected. For example, SAS Pre-Packed and SAS Wire Wrapped Screen (WWS) is red (not recommended) if the reservoir is prone to the effects of fines migration. This is highlighted in Table D-1. Another example is using SAS with the presence of impermeable shale streaks inside an oil bearing zone. In this scenario, Table D-1 indicates orange (use with caution). Caution is needed because a high degree of reservoir lamination can potentially allow shale to embed onto the screen. It can cause plugging and consequently screen damage. To mitigate the risk, SAS should be installed with blank pipes and/or packers to isolate impermeable shale sections. In summary, the user can either proceed using the recommended equipment or re-visit the flowcharts if the risks and concerns are unmanageable.

A range of sand control options has been documented in the methodology. Below are some sand control options (illustrated in Flowcharts A and B) that will be assessed and evaluated for a case study; discussed in the next section:

- **Openhole Standalone Screen (OHSAS)**
  - Wire-wrapped, Pre-packed and Premium
- **Expandable Sand Screen (ESS)**
- **Openhole Gravel Pack (OHGP)**
  - Low Angle Circulating Water Pack
  - High Angle Circulating Water Pack (Alpha/Beta Design)
  - Slurry Pack with Alternate Path/ Shunt Tubes

Flowchart B - Screen and Gravel Size Selection

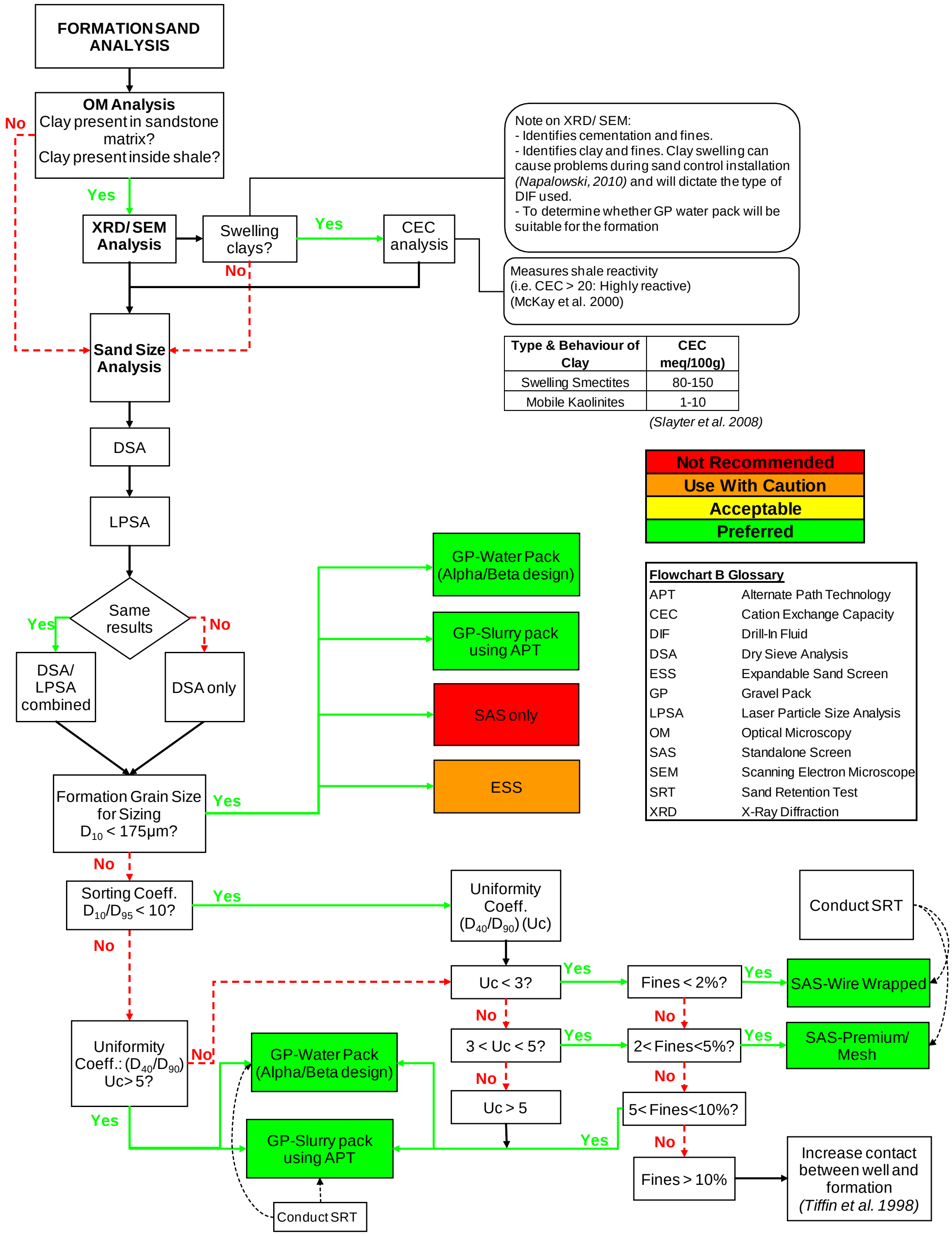

Figure 2: Flowchart B represents 'Screen and Gravel Size Selection'.

Results: Verification of Methodology

Case Study – North Sea Field, UK

Background. The North Sea field was initially discovered in 2006. It lies in the UK sector of the North Sea at a water depth of 370 ft. There are two turbidite reservoirs of interest located in two sandstone reservoirs. For this case study, these reservoirs are called Sand 1 and Sand 2 – the former is divided into five zones and the latter divided into three zones. Figure E-1 in Appendix E shows the vertical subdivision of the reservoirs. Sand 2 has some support from an aquifer but Sand 1 has little natural pressure support. Both reservoirs are separated by shale, and it is uncertain whether or not Sands 1 and 2 are in communication.

Sand 1 is highly heterogeneous. It contains thinly bedded sand and shale streaks (1-2 ft) embedded inside the sandstone matrix. The porosity ranges between 14-20%, permeability in the order of 0.2–0.7 D, and net-to-gross between 33-83%. On the other hand, Sand 2 is more homogeneous with little shale content. It consists of clean quality sandstone with a thick intra-bedded shale formation (15-20 ft) separating the upper and lower zones. It has porosity in the range of 18-24% and permeability in the order of 0.7-1.4 D.

Available data is obtained from several appraisal wells (Table E-1). Study of the appraisal cores and wireline logs shows sand failure will occur and sand control is required when completing these wells.

Injection Strategy. The overall objectives of the water injectors are to dispose produced water back into the reservoir, optimise sweep efficiency to improve oil recovery and provide reservoir pressure maintenance. Initially, the water will be injected under the matrix regime. Over time, injectivity losses may occur as a result of the failed sand plugging the formation. To mitigate this, the design of water injectors will have the capacity to maintain and increase injection pressures to levels resulting in formation fracturing. Therefore, this requires a well trajectory that will give the maximum connectivity between the wellbore and formation. To achieve this, the orientation of the in-situ stress for the field must be determined in order to predict the orientation of the induced fractures. Cold Low Sulphate Seawater (LSSW) and produced formation water will be used as the injection fluids. This will enhance the creation of induced fractures by thermally reducing the fracture pressure (Perkins and Gonzales *et al.* 1984, Svendsen *et al.* 1991).

The design capacity of the water injectors is shown in Table E-2. The water injectors will be drilled in the oil and water leg of Sands 1 and 2 respectively. One out of the six water injectors will commingle and provide injection support into both reservoirs. The initial reservoir pressure (P_i) for both reservoirs varies from 3191 to 3335 psia. Stimulation shows with water injection support, the maximum depletion (ΔP) for both reservoirs are expected to drop between 400-500 psia, which is still above the bubble point pressure (P_b). To achieve this, stimulation shows the injections are required from 10, 000 to 28, 000 stbw/d for Sand 1 and 14, 000 to 35, 000 stbw/d for Sand 2.

The design of the water injectors will have the capacity to accommodate injection rates in the range of 40, 000 to 50, 000 stbw/d. Figure E-2 shows the reservoir simulation of the water injectors for the first 11 years. The water injectors labelled I1 and I2 represent wells in Sands 1 and 2, respectively. Well I1/I2 means the water injector injects into both reservoirs.

Rock Mechanics and In-Situ Stresses.

The load on a rock depends on in-situ stresses, reservoir pressure and drawdown. Understanding the evolution of formation in-situ stresses is an important step in rock mechanics. Sources of these stresses are vertical (σ_v), horizontal maximum (σ_H) and horizontal minimum (σ_h). The magnitude and orientation of these stresses are critical parameters especially when injecting water in the fracture regime. The wellbore should be accurately oriented along an azimuth parallel to σ_H (White *et al.* 2011). A good connectivity between the wellbore and formation fractures will optimise injectivity into the reservoir.

For this case study, σ_v is approximated by a gradient of 0.97 psi/ft using Equation F-1 in Appendix F. The σ_v reflects the weight of the earth above the depth of interest. The σ_h stress gradient is approximated at 0.75 psi/ft using Equation F-2 (below). The equation was determined from previous Leak-Off Tests (LOT) and Formation Integrity Tests (FIT). Applying Equation F-2, σ_h=5378 psi at 7150 ft TVDSS. The σ_h is similar to the outcome of injectivity test from a nearby appraisal well (Well D), where the fracture opening pressure (P_{frac}) was 5450 psia (Figure F-1 in Appendix F). The similarity proves σ_h gradient is valid for this case study.

The magnitude of σ_H is difficult to calculate. In most cases, all of the in-situ stresses are not required as the σ_v and σ_h are the key parameters in predicting sand production. Using North Sea anisotropy (σ_H/σ_h) of 1.08, σ_H can be calculated. Here, σ_v (0.97 psi/ft) is larger than σ_H and σ_h (0.81 psi/ft and 0.75 psi/ft) (σ_v>σ_H>σ_h). This is common but may not true be for active-tectonic areas; where σ_v can be the intermediate or smallest stress.

The orientation of σ_h can be determined from caliper or by examining drilling-induced fractures using Formation Image (FMI) logs. Figure 3 below shows there is no evidence of borehole breakouts or drilling-induced fractures in both the caliper and FMI logs. Figure F-2 in Appendix F shows the same result through a shale section in Well D.

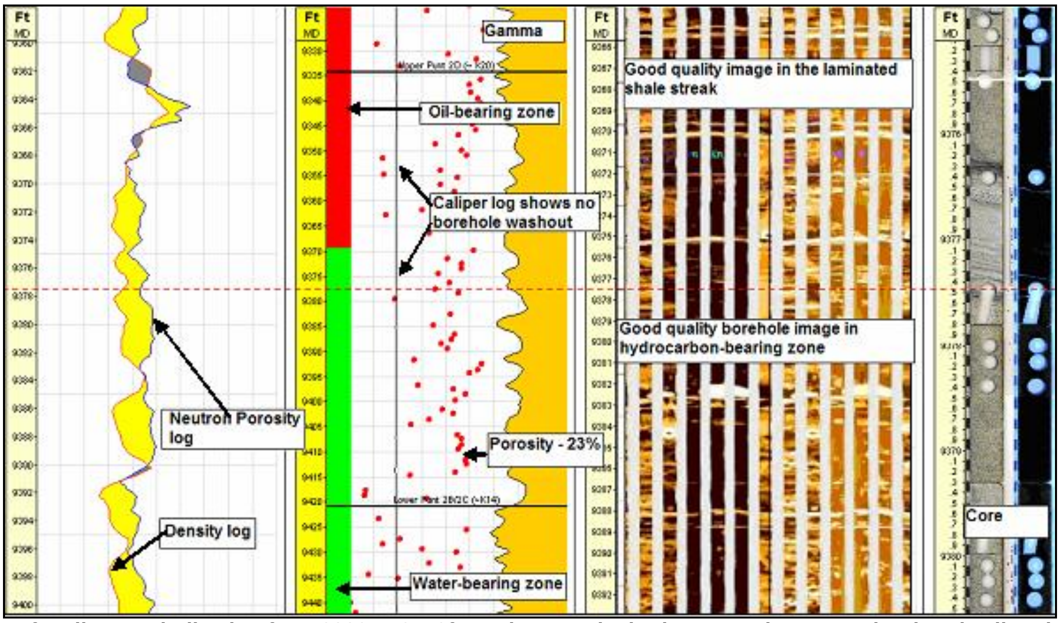

Figure 3: Section of Well Est1 wireline log from 9330 to 9440ft MD (Reservoir 1). The Formation Image (FMI) and caliper logs show no evidence of borehole breakouts and washouts respectively.

Absence of borehole breakouts in the appraisal wells suggests that σ_H and σ_h may have little anisotropy in the horizontal plane ($\sigma_V > \sigma_H \sim \sigma_h$). A geomechanical study from a nearby field show that σ_H and σ_h have magnitudes similar to each other (i.e. almost isotropic) (Persaud *et al.* 2009).

The uncertainty in determining the in-situ stresses orientations remains large. The World Stress Map (WSM) is a useful starting point to reduce this uncertainty. Figure F-3 shows a schematic of the North Sea regional stresses, revealing that σ_H has a generalised NNW-SSE trend. However, the scale of the North Sea regional stress may be erroneous because the local stress orientation varies from one fault block to another (Yale *et al.* 1994). The regional trend from WSM, however, is fairly consistent with the local stress regimes of two nearby fields; where σ_H direction is 095^o to 275^o (±20^o) (almost W-E trend).

Existing faults in the reservoir will give a clue of σ_H and σ_h orientations. Induced fractures tend to orient themselves in the same direction as the existing faults or along the azimuth of σ_H direction (Gorden *et al.* 2011). This assumption is not valid if the horizontal stress regime of the reservoir has changed between the time the faults were created and now, which is unlikely. Figure F-4 and Table F-1 in Appendix 4 shows the location and the expected fracture orientation of the water injectors. The uncertainties in σ_H/σ_h anisotropy limit the deviations of injectors to less than 30^o (near vertical) across the reservoir interval. This is to ensure efficient fracture connectivity is achieved regardless of the orientation of σ_H.

Particle Size Distribution (PSD).

Core data from the appraisal wells are available for study. These data were used to determine the D10 formation grain size, Sc, Uc and fines. DSA and LPSA techniques are used in combination to ensure the fines portions are accurately quantified. Figures 4 and 5 shows there are large differences of fines portion in Sands 1 and 2 when comparing DSA and LPSA techniques. The large difference is expected because DSA measures larger fines (>44 µm) and LPSA is more accurate for measuring fines below 44 µm. Fines with grain sizes below 44 µm tend to disappear as 'dust' and also adhere to coarser particles during sieving (Slayter *et al.*, 2008). LPSA is therefore used to represent the finer end of the particles in Sands 1 and 2. PSD for Sands 1 and 2 are shown in Figure 6 and Figure 7 respectively.

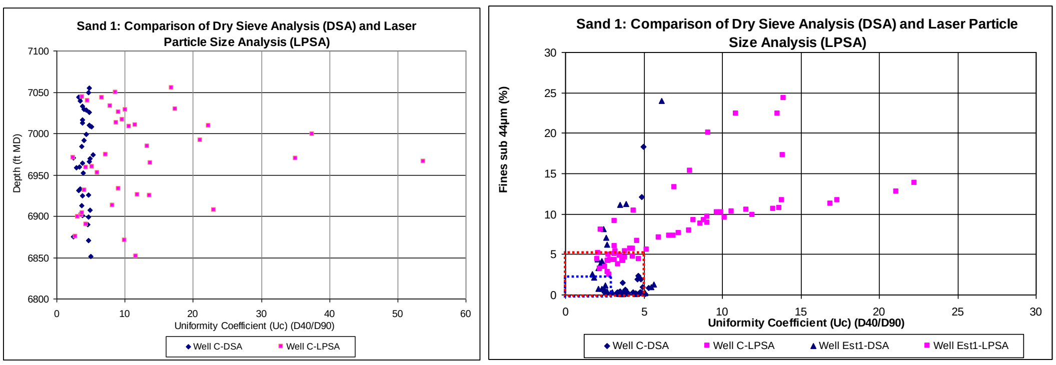

Figure 4: Large variation in fines for Sand 1 show LPSA gives accurate measurement of fines below 44µm.

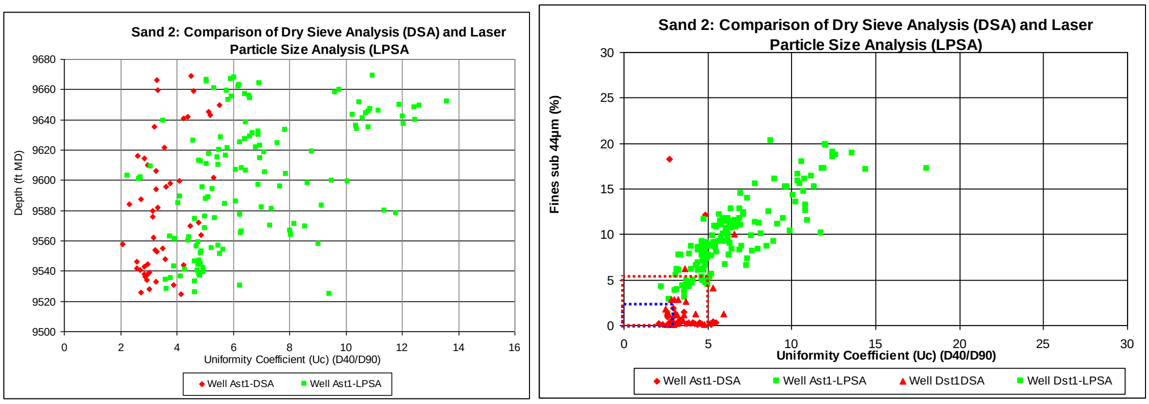

Figure 5: Large variation in fines for Sand 2 show LPSA gives accurate measurement of fines below 44μm.

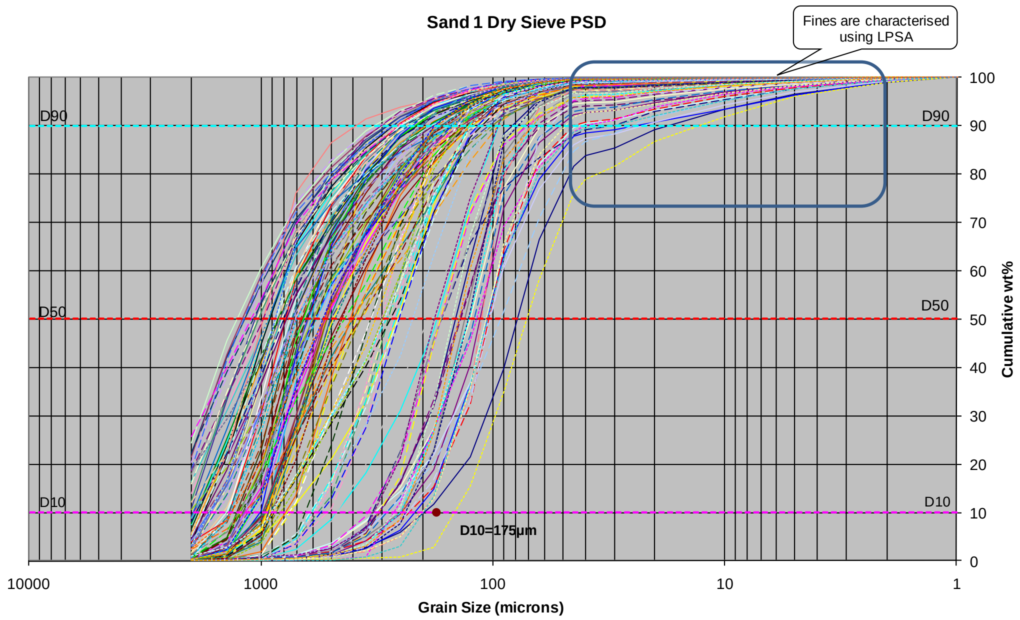

Figure 6: Particle Size Distribution (PSD) of Sand 1 using DSA and LPSA combined (Beesley *et al*. 2011).

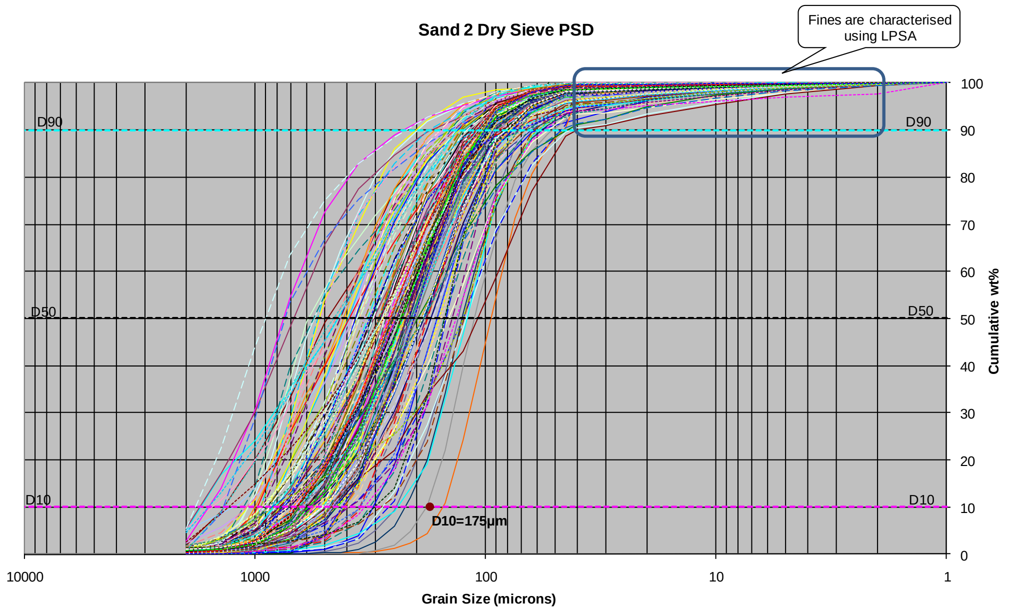

Figure 7: Particle Size Distribution (PSD) of Sand 2 using DSA and LPSA combined (Beesley *et al.* 2011).

***Sand 1.* (Figures and tables in Appendix G, unless stated)**. The D50 median grain size varies widely as shown in Figure G-1. It varies from very coarse (1083 µm) to very fine sand (105 µm) and has a mean size of 515 µm. Figure G-1 shows a range of D50 values obtained from DSA. The large variation in D50 across the samples indicates Sand 1 may be more heterogeneous than Sand 2. D10 varies from 242 to 2137 µm (

Table G-2) with a mean value of 1124 µm. Only one value in Well Est1 (at 9230 ft mD) has a D10 of 149 µm.

Figure G-3 shows 43% of Sc is greater than 10 and that the remaining 57% is less than 10. Figure G-4 shows most of the core samples from Well C, Dst1 and Est1 have Uc values between 2 and 5. This shows the sand is moderately uniform. The percentage of fines is less than 5% and is illustrated in Figure G-5. Based on the selection in Flowchart B, the recommendation is either WWS or Premium/Mesh-type screens. To determine the type of screen, Figure 8 shows a plot of Uc versus fines for Sand 1. It demonstrates most of the fines in Sand 1 lie within the boundaries of a Premium/Mesh-type screen.

***Sand 2*. (Figures and tables in Appendix G, unless stated).** The D50 varies from coarse (609 µm) to fine sand (140 µm) and has a mean value of 286 µm. This is consistent with geological description, where Sand 2 is cleaner and less heterogeneous than Sand 1. Table G-4 shows a range of D50 values obtained from DSA. D10 varies from 283 µm to 1425 µm respectively with an average value of 684 µm. This is illustrated in Table G-5. All D10 values in Sand 2 are greater than 175 µm.

The sand is moderately uniform (2<Uc<5) and fines are below 5%. Using Flowchart B, the methodology also proposes either WWS or Premium/Mesh-type screens. A similar plot is applied to determine the type of SAS. Figure 9 below shows Premium/Mesh-type screen is the recommended sand control option for Sand 2. The methodology is also applied to each formation zone; where Premium/Mesh-type screens are preferred. This is illustrated in Table G-7.

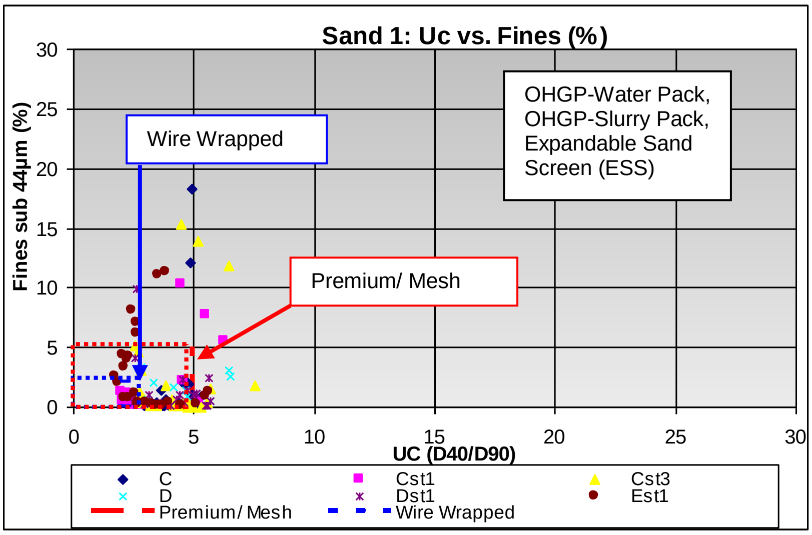

Figure 8: Schematic showing Uc and Fines of Sand 1 within the methodology boundaries to use SAS.

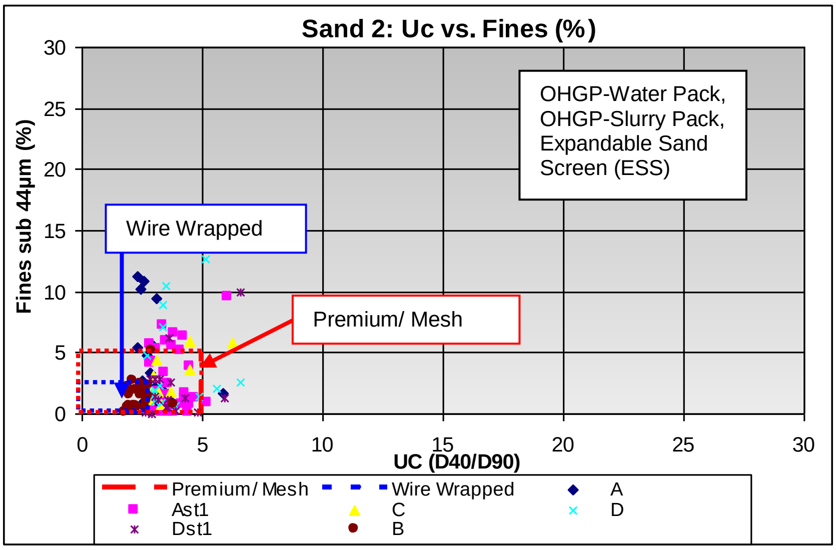

Figure 9: Schematic showing Uc and Fines of Sand 2 also within the methodology boundaries to use SAS.

Formation Heterogeneity.

Shale and Zonal Isolation. Openhole completions provide the greatest opportunity to maximise reservoir flow potential. However, the presence and condition of shale in a productive formation must be investigated, as it may prove problematic. Earlier PSD studies suggest OHSAS is favoured sand control option. This means that the mineralogy study of shale is not essential; it is more useful for OHGP. Mineralogy study of clay swelling helps to determine the compatibility of the gravel pack carrier fluid to shale. If the study shows clay swelling is not critical, a less costly gravel pack carrier fluid can be used over a more sophisticated and expensive option such as lower-viscosity carrier fluid. A significant cost saving can therefore be achieved.

The uppermost zone in Sand 1 (i.e. Sand 1E) is more heterogeneous than the lower zones. Across Sand 1, all five zones contain thin beds of sand and shale with thicknesses of less than 2 ft. Zonal isolation in Sand 1 is difficult. It is also unfavourable to isolate thin shale sections; risking isolating potential pay zones as well. The uncertainty of isolating shale in Sand 1 will be reduced after a well is drilled and logged. For estimation purposes, the thickness of shale layers in the reservoir is determined from the case study appraisal wells. The thickness of shale layers in Sands 1 and 2 are based on shale cut-offs (V_{sh}) of 0.4 and 0.5. This is illustrated in Table H-1 and Table H-2. Using V_{sh} cut-offs of 0.4 and 0.5, it calculates an average and maximum shale thickness of 6 ft and 25 ft respectively. These values are then used to estimate the length of blank pipes and packers.

Sand 2 consists of three zones – Sand 2A, Shale 2B and Sand 2C. Sands 2A and 2C are fairly homogeneous and considered excellent quality sand. It contains low siltstone and mudstone content. Shale 2B is an impermeable zone; separating Sand 2A from Sand 2C. Its thickness varies from 2-36 ft laterally across the reservoir with an average thickness of 11 ft (Table H-3). Flowchart A recommends isolation of shale intervals with thicknesses greater than 30 ft by using a combination of blank pipes and packers.

Permeability Variation. The permeability (k) of Sand 1 varies from 0.2 to 0.7 D and Sand 2 from 0.7 to 1.4 D. Figure 10 and Figure 11 illustrates permeability-porosity (k-ϕ) relationship with porosity cut-offs for Sand 1 and Sand 2 respectively. The left plot on Figure 10 shows Sand 1 has a wider k-ϕ distribution and lower R^2 values compared to Sand 2 (Figure 11). This is another indication that Sand 2 is cleaner and less heterogeneous than Sand 1.

The R^2 values are obtained by applying a best fit regression of the k-ϕ relationship. The higher the R^2, the less heterogeneous the formation is. Table H-4 in Appendix H summarised the regressed R^2 values for all the appraisal wells. The average R^2 values are therefore 0.78 and 0.83 for Sand 1 and Sand 2 respectively. However, the R^2 needs to be verified because the value is also dependant on sorting. This is conducted by plotting the Rock Quality Index (RQI) versus Sc. This is illustrated in Figure H-1 and Figure H-2 for Sands 1 and 2 respectively. Figure H-1 shows a wider RQI and Sc distribution (i.e. less sorted) compared to Figure H-2. In short, this concludes that a more sorted formation is less heterogeneous (Sand 2) and a less sorted formation is more heterogeneous (Sand 1); validating the use of R^2 to represent heterogeneity in this study.

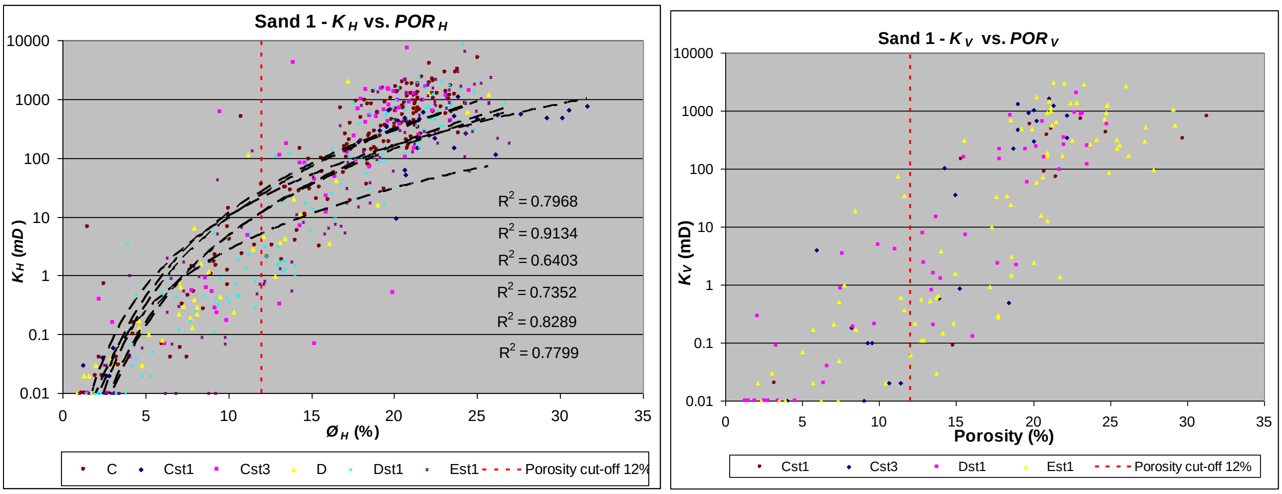

Figure 10: Permeability and porosity relationship of Sand 1 in the horizontal and vertical direction.

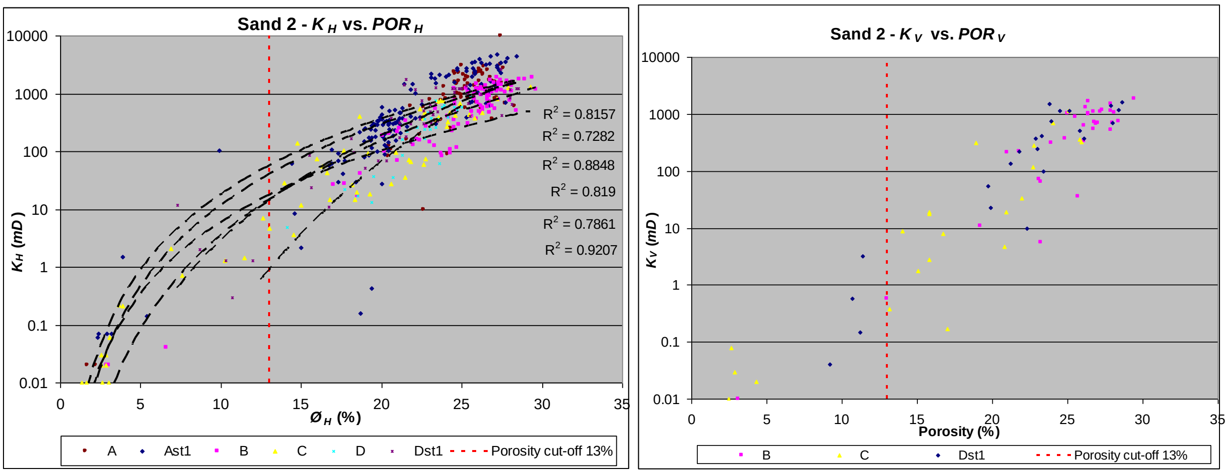

Figure 11: Permeability and porosity relationship of Sand 2 in the horizontal and vertical direction.

Uncertainty in determining permeability variation in a pre-drilled injector is large. However, study of nearby appraisal wells suggests there is a large variation in permeability; especially in Sand 1. Figure 12 shows Sand 1 has anisotropic vertical (k_V) and horizontal (k_H) permeabilities, with a vertical-horizontal permeability ratio (k_V/k_H) ranging from 0.001 to 100. Following that, Figure 13 shows Sand 2 is less anisotropic compared to Sand 1. More k_V/k_H plots for Sands 1 and 2 are illustrated in Figure H-3 in Appendix H. Flowchart A recommends the use of blank pipes, packers and inflow control technology to counteract the effects of permeability variation in Sands 1 and 2. Large permeability variation can result in several aforementioned failure mechanisms that are common in water injectors.

Split Injection Rate and Annular Flow

As the need for inflow control technology to be integrated with SAS has been established, a study on how to design and optimise this integrated completion is required. Inflow-control technology will help to optimise sweep efficiency in highly heterogeneous Sand 1 and provide pressure support in Sand 2. It will also help to avoid formation fractures in the high permeability zones by controlling the amount of water intake. 'Active' ICV and 'Passive' ICD (Birchenko *et al.* 2008) helps to improve equalisation and distribution of water evenly across each pay zone. The base design is to position one ICV combined with openhole packers per zone. ICV is preferred because it is surface-controlled and does not require well intervention. ICD however is more suited to counteract the 'heel-to-toe' effect seen in horizontal wells (Birchenko *et al.* 2008).

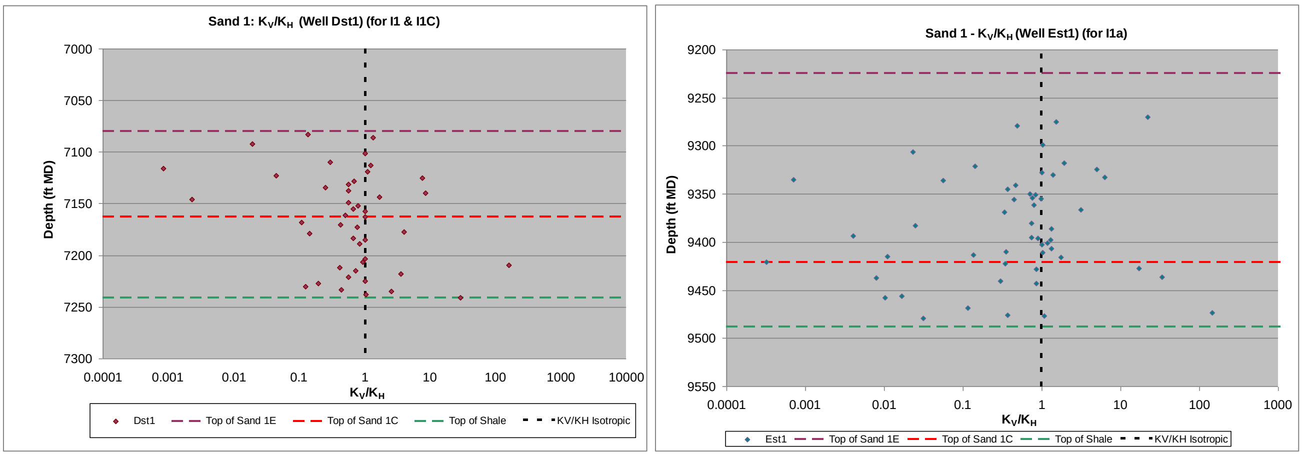

Figure 12: Vertical-to-horizontal permeability ratio (K_V/K_H) in Sand 1 is more anisotropic than Sand 2.

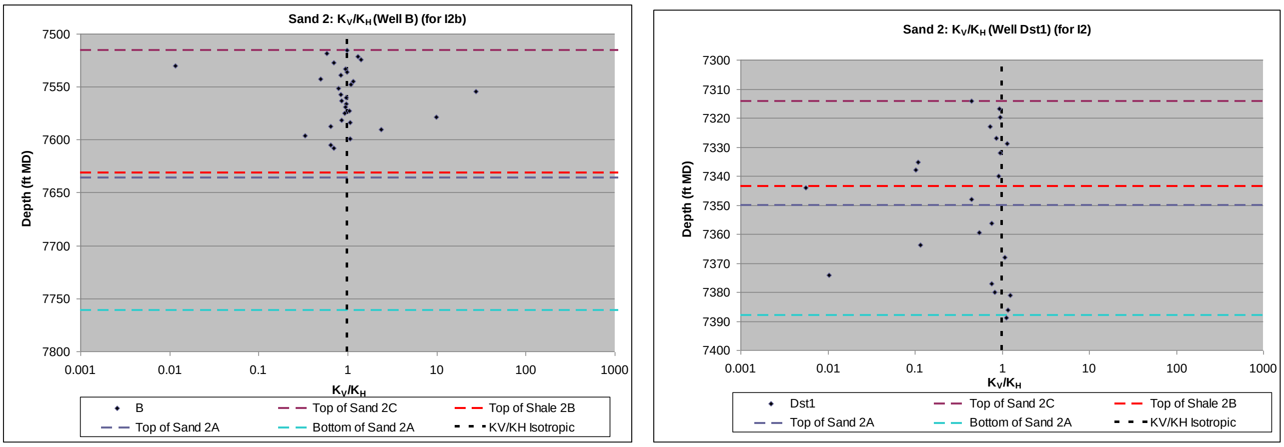

Figure 13: Schematic shows the K_V/K_H in Sand 2 is less anisotropic compared to Sand 1.

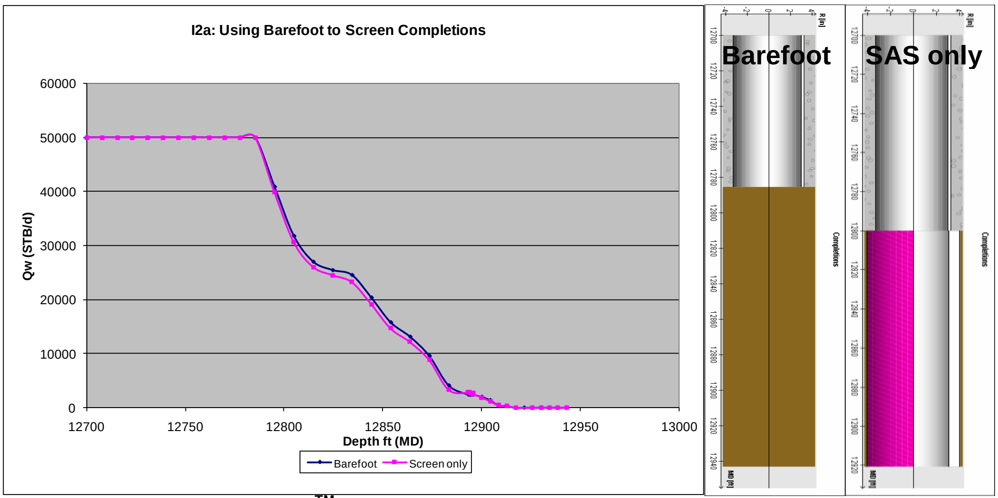

Figure 14: NETool™ shows Barefoot and SAS completions matches.

NETool™ wellbore simulation is used to model the injection profile in SAS with integrated ICV. It simulates the volume of water injection into each pay zone based on the position and settings of ICVs. For instance, if a high permeability pay zone takes more water, optimising the ICV aperture in NETool™ can control the increased injection. This will improve water distribution meaning better pressure support and an efficient drainage of water into all zones. A workflow explaining the process of NETool™ simulator is explained further in Appendix K. NETool™ has one limitation – the software cannot simulate the injection profile when SAS is modelled with ICV. This is because an ICV is installed within the SAS. Therefore, the simulation can only model openhole (barefoot) completion with ICV, assuming it as SAS with ICV. To validate this assumption, injection profiles with barefoot- and SAS-only completion are stimulated, and highlighted in . Both injection profiles in matches, which means barefoot with ICV can be used as a model to resemble SAS with ICV.

Average permeability-thickness (*kh*) in Sands 1 and 2 are used to calculate the injection allocations (i.e. split ratio) of each zone. The objective of determining the allocations each zone is to tailor the ICV settings. In doing this, water injection can be optimised for each zone according to the calculated allocations. Table I-1 to Table I-4 in Appendix I summarises the injection allocations for all water injectors in Sands 1 and 2.

For this case study, I1 and I2 represent the water injectors in Sand 1 and Sand 2 respectively. I1b is used as an example for this case study and illustrated in Figure 15. Design capacity for this well is 40, 000 stbw/d; which is in the fracture injection regime. I1b has reservoir drainage of 220 ft. Its *kh* split ratio is 52% (Upper Sand 1) and 48% (Lower Sand 1). This means the design injection rates are 20, 700 stbw/d and 19, 500 stbw/d for Upper Sand 1 and Lower Sand 1 respectively. Simulation was initially conducted with SAS-only completion. The injection profile in SAS-only completion shows 77% of water will be injected into Upper Sand 1. This creates an uneven distribution of water; meaning ICV will be required to balance the injection profile. Optimisation of SAS completed with various ICV apertures is sensitised. The outcome of the sensitivity analysis is an optimised ICV configuration that matches the injection allocations. The results show that both ICVs in I1b with a 5% opening will give injection rates of 20, 800 stbw/d and 19, 200 stbw/d into Upper Sand 1 and Lower Sand 1, respectively. This shows injection into Upper Sand 1 can be reduced to 52% of the total injection rate compared to 77% for an SAS-only completion. This means less water injection into Upper Sand 1 and more water injection into Lower Sand 1. Figure 16 shows the water flux profile for SAS-only and SAS-ICV completions. The plot shows an improved fluid flow across Sand 1 when ICVs are used.

The injection rates based on the optimised ICV for all water injectors are highlighted from Table I-5 to I-7 and the ICV settings are summarised in Table I-8. Plots to compare injection allocations, water flux profiles and completions for the other five injectors are in Figure I-1 to I-10.

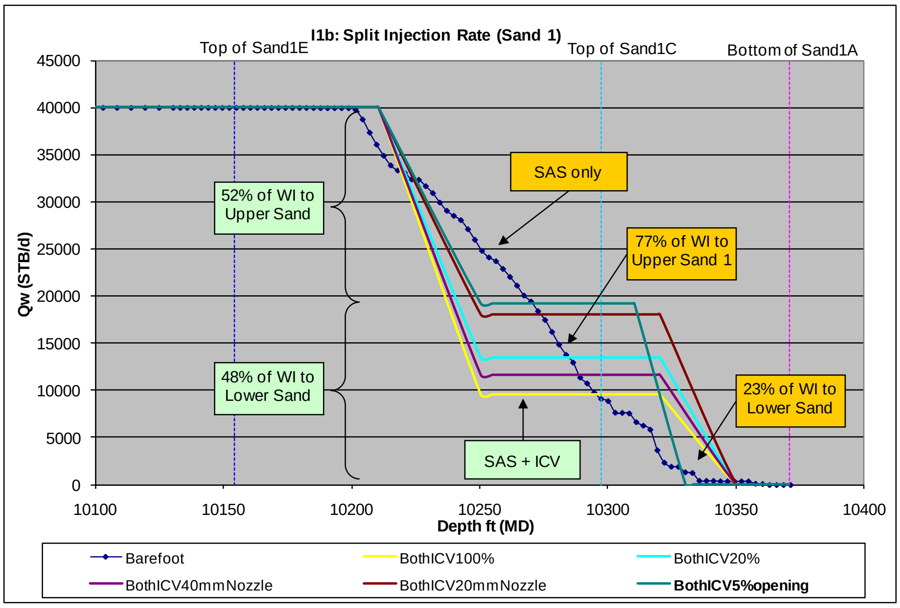

Figure 15: Split design injection rate into the Upper & Lower Sand 1 for I1b.

In SAS-ICV injectors (Figure 17), water will flow out of the well (blue arrow) and into the annulus (red arrow). Most of the water will flow into the reservoir whilst the remaining water will flow in the annulus. Sensitivity analysis with water injection rates at every ten thousand barrels from 10, 000 to 50, 000 stbw/d shows there is some fluid velocity in the space between the SAS annulus and openhole wellbore.

The annular velocity profile of I1b injector in Figure 18 shows the topmost screen joint (i.e. the heel) is potentially the weakest point in the completion and the screen is expected to fail first as a result of hot spotting. This effect causes screen plugging and erosion if the annular fluid velocity exceeds the erosion (threshold) velocity (V_e). The V_e varies among operators and is controlled by solids content of the injected fluid, fluid particles size and SAS selection (Cameron *et al.* 2007). Several references suggested the safe limits of annular flow velocity for WWS and Premium screens are 1 ft/s and 2 ft/s respectively (Wong *et al.* 2003).

The maximum annular flow velocity in Figure 18 at the topmost screen joint is 2 ft/s, if the water is injected at 50, 000 stbw/d. At lower injection rates, the effect of annular velocity reduces. Reservoir strategy for this well shows the maximum injection rate is 24, 000 stbw/d and averages at 12, 000 stbw/d. In this case, the risk of screen erosion caused by hot spots is minimal. If reservoir management calls for water injection up to 50, 000 stbw/d from I1b, risk of screen erosion is moderate and still within acceptable limits. The study also shows compartmentalisation using packers have minimal effect on reducing the annular velocity. This is demonstrated in Figure I-13, where up to four packers were used to isolate and did not reduce the annular velocity. Sensitivity analyses on the annular velocity of the other water injectors are illustrated from Figure I-11 to Figure I-13. In summary, Sand 1 has low risk of screen erosion between 10, 000 – 30, 000 stbwd, moderate risk at 40, 000 stbw/d and high risk at 50, 000 stbw/d. Sand 2 has low annular velocity risk for all water injection rates except for the commingling water injector. The results of the sensitivity analyses are highlighted in Table I-9.

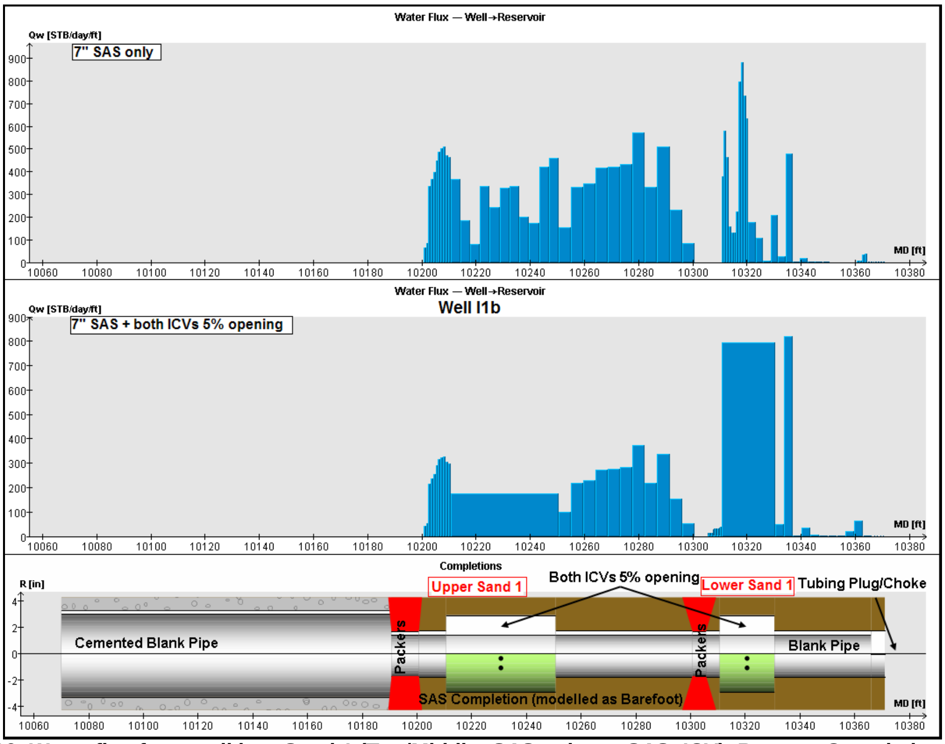

Figure 16: Water flux from well into Sand 1 (Top/Middle: SAS only vs. SAS+ICV). Bottom: Completion design.

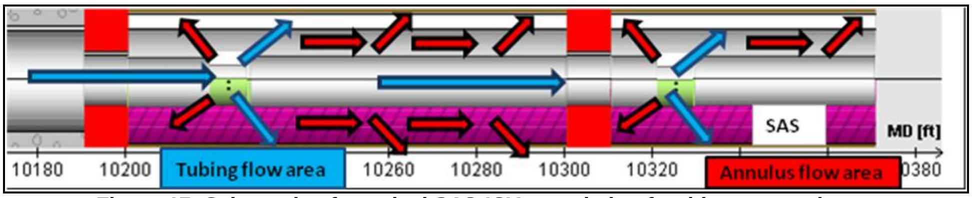

Figure 17: Schematic of a typical SAS-ICV completion for this case study

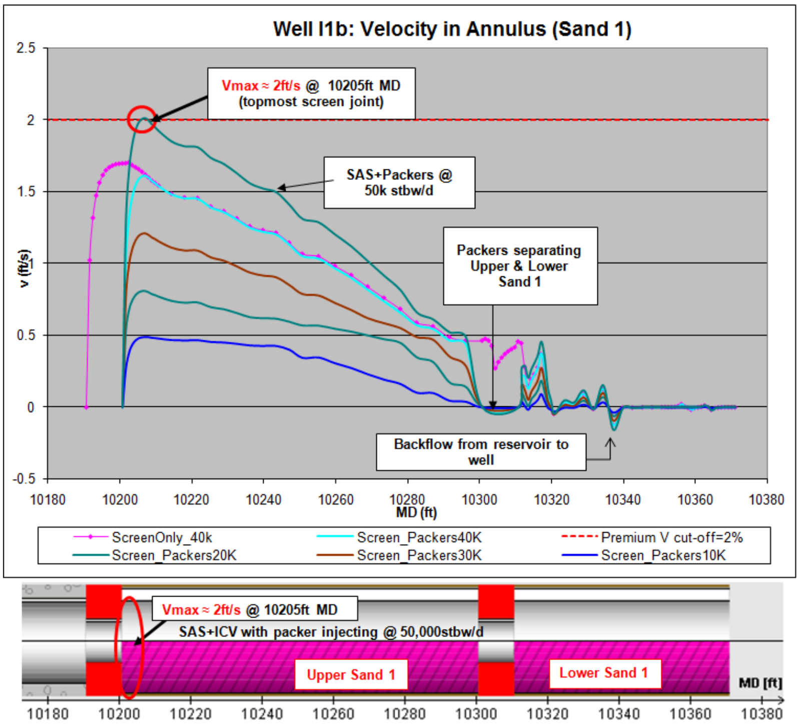

Figure 18: Annular velocity (*v*) with zonal isolation in the integrated SAS+ICV completion. The circled (red) shows the top most screen joint is the weakest point of the completion.

Conclusions

A new methodology, this paper recommends sand control selection in a concise and easy to understand manner for six water injectors in a North Sea field. The methodology is presented as a combination of flowcharts and a sand control selection table matrix, enabling the engineer to assess the risk of the recommended equipment.

The water injectors are vertical or deviated at less than 30^o into the reservoir sections and independent of σ_H azimuth orientation. Sand control for all six water injectors in Sands 1 and 2 has been evaluated in accordance to this new methodology as per below:

- Openhole SAS is the preferred technique.
    - Premium-type SAS is recommended, because most of the sand has D10 greater than 175 µm, moderately uniform, and have fines of less than 5%. This option is suitable to accommodate an injection capacity of up to 50, 000 stbw/d and remain stable under a high rugosity wellbore.
    - WWS is not recommended. Prone to fines migration, WWS is susceptible to screen erosion and plugging. Both reservoirs have fines greater than 2%, exceeding the methodology boundaries that enable them to use WWS.
- OHGP such as LAWP, HAWP and Slurry Pack are not recommended because gravel packs are likely to displace when injecting at fracture regimes. OHGP also has higher operational risks, and is a more expensive option.
- Cased Hole Gravel Pack (CHGP) and High Rate Water Pack (HRWP) are also not recommended as both may suffer from limited outflow, perforation plugging and high completion skin values. In fact, wellbore stability for this case study shows that casing is not necessary.

Premium-type SAS utilising blank pipes and packers will be integrated to isolate shale sections. ICV will be included to even out the non-uniform distribution of water injection, caused by the effects of permeability variation. In addition, NETool^{TM} modelling simulates different optimised ICV apertures to match the injection allocations for all water injectors; calculated from permeability-thickness. Sensitivity analyses at various injection rates shows flow velocity in the screen annulus is below the critical erosional velocity for Premium-type SAS.

In summary, the methodology is validated and supplemented by risks and concerns. The risks are large permeability variation and presence of shale in the oil bearing zones. As long as ICV, blank pipes and packers are included to manage the risks, the use of Premium-type SAS as a sand control equipment for this case study is justified.

Suggestions for Further Work

- Expand the methodology further for cased hole sand control
- To include sand retention study and design of screen slot sizing in the methodology
- Simulate and compare injection flow profiles in the field's production life.
- The evaluation of installing back-flow check valve to reduce the water 'hammer' effect when wells are shut-in.
- Comparison of injection performance (nodal analysis) for various sand control options using Skin, Injectivity Index (II) and Completion Efficiency (CE) as the sensitivity parameters.

Nomenclature

ΔP	Pressure Drop [psi]
APT	Alternate Path Technology
bbl/d	Barrels per day
CEC	Cation Exchange Capacity
CHGP	Cased Hole Gravel Pack
D	Darcy
D10	Particle Size (10th percentile)
D40	Particle Size (40th percentile)
D50	Particle Size (50th percentile)
D90	Particle Size (90th percentile)
DIF	Drill-In Fluids
DSA	Dry Sieve Analysis
ESS	Expandable Sand Screen
FMI	Formation Image Log
GP	Gravel Pack
HRWP	High Rate Water Pack
I1	Sand 1 Water Injector
I2	Sand 2 Water Injector
ICD	Inflow Control Device
ICV	Inflow Control Valves
ID	Internal Diameter
k_H	Horizontal Permeability [mD]
kh	Permeability Thickness [md.ft]
k-$ø$	Permeability-Porosity Relationship
k_v	Vertical Permeability [mD]
k_v/k_H	Vertical-Horizontal Permeability Ratio
LPSA	Laser Particle Sieve Analysis
MD	Measured Depth
NAF	Non Aqueous Fluid
NTG	Net to Gross [%]
OBM	Oil Based Mud
OD	Outer Diameter
OHGP	Open Hole Gravel Pack
OM	Optical Microscopy
P_{frac}	Fracture Opening Pressure [psia]
PLT	Production Logging Tool

PPS	Pre-packed Screen	Uc	Uniformity Coefficient (D40/D90)
PSD	Particle Size Distribution	v	Annular Fluid Velocity [ft/s]
R^2	Linear Regression	V_e	Critical Erosional Velocity [ft/s]
RQI	Rock Quality Index	WBM	Water Based Mud
SAS	Standalone Screen	WC	Wellbore Condition
Sc	Sorting Coefficient (D10/D95)	WI	Water Injector
SCS	Sand Control Selection	WWS	Wire Wrapped Screen
SEM	Scanning Electron Microscopy	XRD	X-Ray Diffraction
SOBM	Synthetic Oil Based Mud	μm	Micron
SRT	Sand Retention Test	σ_H	Maximum Horizontal Stress Gradient [psi/ft]
st	sidetrack	σ_h	Minimum Horizontal Stress Gradient [psi/ft]
stbw/d	Stock Tank Barrels of Water per Day	σ_v	Vertical (Overburden) Stress Gradient [psi/ft]
TVDSS	Total Vertical Depth Subsea		

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APPENDICES

APPENDIX A: CRITICAL LITERATURE MILESTONES TABLE

Paper	Year	Title	Authors	Contribution
58-066 (API)	1958	"Sand Exclusion in Oil and Gas Wells"	G.H.Tausch, C.B.Corley	First to discuss the theory and methods of sand exclusion i.e. bridging and consolidation of sand grains.
2330	1968	"Successful Sand Control Design for High Rate Oil and Water Wells"	D.H.Schwartz	1. First to describe sand control design procedure for oil producer and water injector wells. 2. First to present methods for designing gravel packed completion.
39437	1998	"New Criteria for Gravel and Screen Selection for Sand Control"	D.L.Tiffin, G.E.King, R.E. Larese, L.K.Amoco	1. First to present guidelines for sand control completion technique and gravel size selection based on reservoir sand size distribution. 2. Consolidated proposed design criteria based on field experience and experiments on cores from various formations.
85540	2003	" Design Methodology for Selection of Horizontal Openhole Sand-Control Completions Supported by Field Case Histories"	C.Price-Smith, C.Bennett, J.M.Gilchrist, E.Pitoni, R.C.Burton, R.M.Hodge, J.Troncoso, S.A.Ali, R.Dickerson	1. First to propose a generalized and unified methodology for determining when, what and how to install horizontal openhole completions. 2. Presented a risk analysis by integrating all relevant factors.
88493	2004	"Screening Methodology for Downhole Sand Control Selection"	C.Farrow, D.Munro, T.McCarthy	First to propose a methodology incorporating a combination of flowchart and sand control selection matrix.
93564	2005	"Designing Effective Sand Control Systems to Overcome Problems in Water Injection Wells"	H. Sadrpanah, R. Allam, A.Acock, M.Norris, T.O'Rouke	1. First to provide guideline in selecting and designing sand control systems for water injector wells. 2. Summaries causes of sand control failures based on detailed case studies.
106018	2007	"ICD Screen Technology Used To Optimize Waterflooding in Injector Well"	A.G. Raffn, S. Hundsnes, S. Kvernstuen, T. Moen	Propose an innovative completion of inflow control technology with sand control screens for injection wells
107539	2007	"Successful Installation of Stand Alone Sand Screen in More Than 200 Wells – The Importance of Screen Selection Process and Fluid Qualification"	A.M.Mathisen, G.L. Aastveit, E. Alteras	1. First to recommend a sand control selection practice based on comprehensive screen selection and fluid qualification process. 2. First to publish testing and ranking of different screen designs based on sand retention and plugging properties.
112283	2008	"Equalization of the Water Injection Profile of a Subsea Horizontal Well: A Case History"	A.S. Amaral, J. Augustine, K. Henriksen, V.F.,Rodrigues, D.E. Steagal, L.C.A.Paixao	First global installation of a water injector well with a lower completion system that include both premium sand control screens and inflow control technology to equalize injection profile.
114781	2008	"Sand Management: What Are We Sure Of?"	A.G. Slayter, M.Byrne, C.A. McPhee, P.McCurdy	First to propose a methodical framework with defined objectives, tasks and activities for the execution and qualification of sand control design
128038	2010	"Improved Selection Criteria for Sand Control – When Are "Fines" Fines?"	M.Byrne, A.G. Slayter, P.McCurdy	First to redefine classification of "fines" by considering the impact it has on the formation and its ability to move through the pores of unperturbed rock
137057	2010	"Optimizing Injection Wells through Innovative Completion	A. Khalil, M. Elasmar, S. Shafie	First to apply influx control device (ICD) in an injector well for carbonate formation.

APPENDIX B: CRITICAL LITERATURE REVIEWS

API 58-066, 1958
First presented during a meeting at the Southern District, Division of Production, Houston, Texas, February 1958.

Title: Sand Exclusion in Oil and Gas Wells

Authors: Tausch, G. H., Corley C. B. Jr.

Contribution to the understanding of sand control concept selection: This paper describes the two general methods of sand control. The methods are 1) bridging of sand grains and 2) consolidation of sand in place. Each method also describes the design criteria required when selecting a sand exclusion technique.

Objective of the paper: A detailed examination of sand exclusion techniques. The techniques studies are slotted/wire-wrapped screen, gravel packing, plastic coated walnut shells and plastic consolidation.

Methodology used: The bridging of sand grains is controlled by the size of the openings in the standalone screen and gravel pack. The size of the openings is determined by analysing the D10 sieved from dry analysis. The D10 i.e. the formation sand sizing grain diameter is an important criterion for the design of the bridging method. Consolidation of grains uses plastic material and the critical design criteria are formation permeability and temperature instead.

Conclusion reached: Bridging techniques can be applied on initial completion and consolidation techniques after completion (i.e. when there is an indication of formation sand produced). Both techniques have different design criterion.

Comments: This paper unifies sand control techniques into two techniques for both oil and water-producing wells. For the bridging method, the paper describe slotted line, wire wrapped screens and gravel pack as the solution. Detailed design and effectiveness of the sand control equipment was only briefly discussed. The grain size analysis focussed only on the minimum formation size (D10) for the screen slot design.

Journal of Petroleum Technology, September 1969
Presented at the SPE 39th Annual California Regional Fall Meeting held in Bakersfield, USA 7-8 November, 1968

Title: Successful Sand Control Design for High Rate Oil and Water Wells

Authors: Schwartz, D. H.

Contribution to the understanding of sand control concept selection:

Objective of the paper: To present a technique for designing gravel flow packed liner completion. Design criteria are formation analysis, gravel-to-sand ratio and velocity through slots. The objective is to design a sand control for high rate oil producer and water injections wells. Subsequently, a sand control design is recommended that is sufficient to last through secondary recovery projects (~ 10 years).

Methodology used: Describes the Tyler Standard Screen Scale (sieve analysis) to measure the grain diameter (D_x) and uniformity coefficient (C). D_x refers to the sieve size distribution (cumulative, %). C is determined from the slope of the sieve analysis:

$$C = D40/D90$$

The equation above shows a sieve opening at which 40% of the sand is being retained divided by another sieve opening at which 90% of the sand is being retained. Below is the description of the C value:

C < 3: Uniform Sand
C > 5: Non-uniform sand

Describes the parameter of the Gravel-to-Sand Ratio (G-S) i.e. the gravel grain size to the formation sand grain size:

- G-S ≤4 will give a stable pack
- G-S between 10 and 13 will give an unstable pack due to the invasion of formation into the pack
- G-S between 6 and 8 will give the most optimum design

The final methodology describes the effects of velocity towards the gravel flow pack. Increasing velocity will tend to destroy the pack stability. A design curve was plotted in determining the gravel and formation critical grain size for the design of the gravel and screen opening respectively.

Conclusion reached: Successful and control design can be achieved by defining the sand, gravel design and quality of control of gravel once it is in place.

Comments: The paper provided some understanding of how to measure the sand grains from sieve analysis. The methodology focuses solely on gravel pack techniques.

SPE 39437, 1998
This paper was presented at the 1998 SPE Formation Damage Control Conference held in Lafayette, LA, 18-19 February

Title: New Criteria for Gravel and Screen Selection for Sand Control

Authors: Tiffin, D.L., King, G. E., Larese, R. E., Britt L. K.

Contribution to the understanding of sand control concept selection: A proposed criterion has been published focussing primarily on reservoir sand size distribution. The criterion methodology focuses on the distribution of the grain sizes in terms of sorting. The study also evaluates the concerns of formation with very high fines content. Methodology uses field experience and experiments on reservoir cores worldwide as part of the study.

Objective of the paper: To propose a new sorting criteria and completion techniques relating to the selection of gravel and screen size. The proposed criterion focuses on sorting techniques and mobility of fines.

Methodology used: Added a new piece of design information to the commonly used Saucier's criteria for screen and gravel size selection. Design methodology uses D50, D40/D90, D10/D95 and mobility of fines particles for sand control selection. If D50 < 75µm, gravel pack is preferred as fines constitutes a large portion of the sand distribution making screens impractical. The D10/D95 is a new criterion and used to distinct variation between the size and sorting ranges of formation sand.

Conclusion reached: The proposed criteria for evaluating formation sand sorting values are presented below:

Table B-1: Formation Sand Sorting Values

Sorting	Proposed Purpose
D50	Standard Saucier Criteria
D40/D90	Screen Damage Ratio from Pall
D10/D95	Size range between common minimum and maximum particle sizes
Sub 325 mesh	Quantity of sub 44micron particles (fines)

Several case studies were conducted using the methodology and summarised below:

Table B-2: Proposed Sorting Criteria

Completion Techniques	D40/D90	D10/D95	Sub 325 mesh (fines)
Bare screen	<3	<10	<2%
Bare screen with woven mesh screens	<5	<10	<5%
Gravel placed in high rate water pack	<5	<20	<5%
Gravel and Fines-passing screen	<5	<20	>10%
Enlarge the wellbore through fracturing or horizontal/ multilateral well	>5	>20	>10%

Comments: This paper presents a solid method in determining the screen and gravel size selection. It highlights the various sorting methods and most importantly the concern of fines mobility. The summary of case studies tabulated above provides a much better understanding of what type of sand control is needed based on the formation sand size distribution. This study also highlights the need to enlarge the wellbore if large quantity of fines is present.

SPE 85504, June 2003
This paper was first presented at the 2000 SPE European Petroleum Conference held in Paris, France, 24-25 February. The paper was revised for publication from paper SPE 65140.

Title: Design Methodology for Selection of Horizontal Openhole Sand-Control Completions Supported by Field Case Histories

Authors: Price-Smith, C., Parlar, M., Bennet, C., Gilchrist, J. M., Pitoni, E., Burton, R. C., Hodge, R. M., Troncoso, J., Ali, S. A., Dickerson, R.

Contribution to the understanding of sand control concept selection: This paper discusses a unified methodology for determining the type of sand control needed for openhole horizontal completions. It highlights a step-by-step guide from predicting sand to establishing the type of sand control needed. The criteria in determining the type of sand control is based on field experience, knowledge and experimental data. This paper also provided a range of critical design criterion when selecting a sand control technique from a range screens and gravel packs available to date. The criterion includes deepwater and non-deep water environments. Several case histories were applied to support the methodology proposed.

Objective of the paper: To propose a unified and well-defined set of guidelines for selecting a sand control technique. The paper provides specific factors that links 'when', 'what' and 'how' to install sand control in openhole horizontal completions.

Methodology used: In deepwater environments (>1500ft), the cost of intervention outweighs the sensitivity cost of screen selection and gravel pack (GP). For non-deep water environments (<1500ft), initial screening uses formation sand size distribution as per Tiffin criteria. The methodology describes the presence of shale in productive sand requires isolation through the use of blank pipes or mechanical inflatable packers.

The methodology highlights in detail the design criterion that affects the type of gravel pack. Two types of GP are commonly used: GP-Water Pack and GP-Shunt Pack. The use of GP-Water Pack depends primarily on the pay length, shale content/ reactivity and drilling fluid compatibility. GP-Water Pack is preferred over GP-Shunt pack when the formation sand is uniform and NTG is high i.e. > 60-80%. Depending on the scenario, GP-Shunt Pack is preferred in high-risk environments because the success ratio for this method is 100%.

The methodology also highlights several critical concerns before and after installing a sand control technique. Details of the methodology are presented in table formats. The proposed methodology was checked and compared against 10 case studies.

Conclusion reached: The methodology (unified set of guidelines) should be use cautiously and requires further validation and refining when selecting the most appropriate sand control. Based on the validating methodology with the case studies, the results is summarised below:

Table B-3: Sand Control recommended using Price-Smith *et al.* methodology

Median Grain Size (D50)	Uniformity (D40/D90)	Fines content	Production Rate	Sand Control Recommended
> 75μm	High	Low	Low	Wire Wrapped Screen
> 75μm	Moderate	Moderate	Low	Prepacked Screen or Premium Screen
> 75μm	High	Low	High	Prepacked Screen or Premium Screen (*Large screen OD required to minimize annular flow*)

- Use gravel pack when D50< 75μm. GP-Shunt Pack is recommended for low NTG, reactive shale, OBM and low fracture gradient. GP-Water Pack is for high NTG, absence of reactive shale, WBM and high fracture gradient environments.
- For deepwater environment (i.e. intervention cost outweighs sand control cost), the most reliable sand control technique must be used.

Comments: This paper gives a detailed overview over a range of design criteria that needs to be conducted prior to choosing the suitable sand control. Further design criterion is added in this paper such as the presence and reactivity of shale, NTG and depth of water. The paper has unified a unique methodology when selecting a sand control technique compared to other published papers. The ten case studies focused on horizontal openhole completions but did not use well length as a design criterion.

SPE 88493, October 2004
This paper was presented at the 2004 SPE Asia Pacific Oil and Gas Conference and Exhibition held in Perth, 18-20 October

Title: Screening Methodology for Downhole Sand Control Selection

Authors: Farrow, C., Munro, D., McCarthy, T.

Contribution to the understanding of sand control concept selection: This paper introduces a sand control selection matrix using a traffic light output system. The system ranks available sand control techniques based on likelihood and consequences. The likelihood factor is based on a range of design criteria and the consequences factor is related to risks.

Objective of the paper: To develop a screening methodology by evaluating and ranking of available sand control techniques. The methodology incorporates a combination of a flowchart and a sand control selection matrix.

Methodology used: The flowchart is used for initial screening. It addresses which sand control options are suitable. The flowchart highlights the type, location and deviation of the well under study.

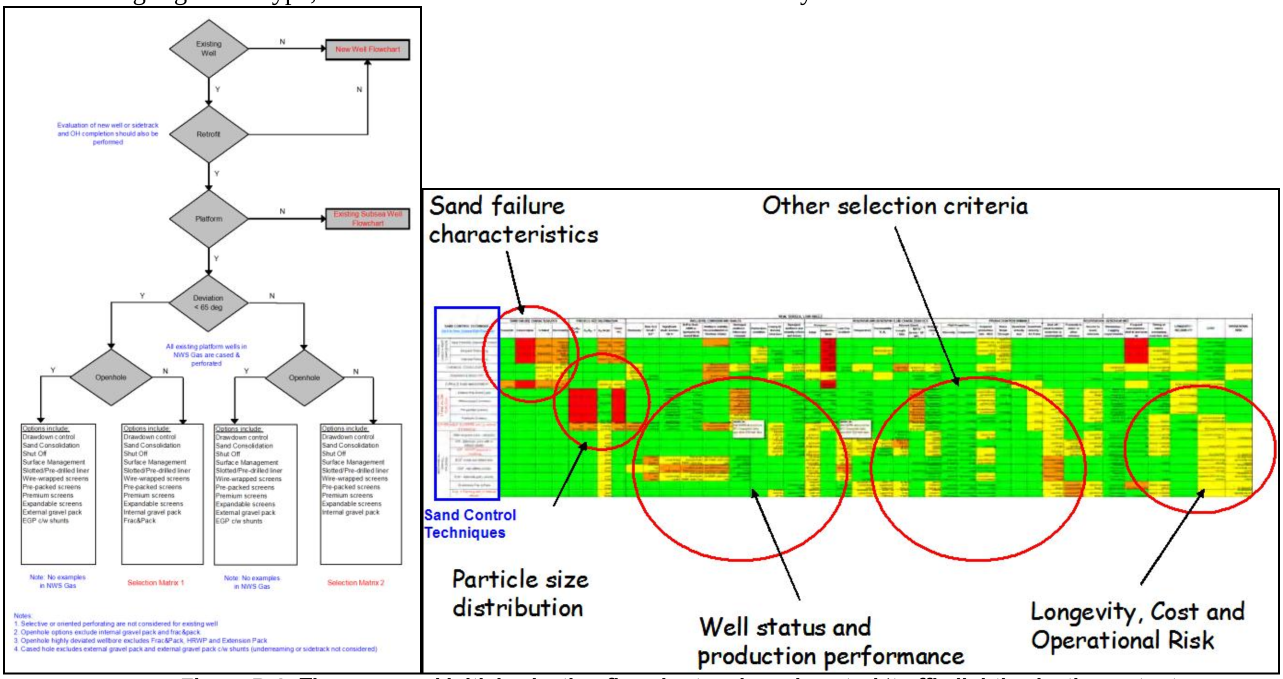

Figure B-1: The proposed initial selection flowchart and sand control 'traffic light' selection output.

The above figure on the right indicates sand control techniques vs. design criteria. The matrix uses a colour code output. Green represent no concerns, yellow = some concern, orange = significant concern and red = ruled out. Any sand control techniques that receives red are eliminated immediately. Remaining sand control options are then evaluated by comparing the colour output of other design criteria.

Selection matrix includes additional design criteria in the sand control selection. The criteria are reservoir length, reservoir fluid characteristics and production performance. Well intervention, cost, reliability and installation are risks criteria that are also included in the matrix. Methodology has been applied on three case studies. Case study 1 and 2 are cased-hole wells on existing platforms. Case 3 is an open-hole well for a sub-sea development. Gravel pack and standalone screen are the recommended sand control option for the former and latter respectively.

Conclusion reached: Screening methodology using the flowchart and the selection matrix enables transparent evaluation and balanced ranking of sand control options. Additional critical design criteria on top of the common ones are highlighted.

Comments: This paper gives a unique methodology for sand control selection. Output of the methodology can be evaluated and compared with established sand control techniques for a particular area. It uses a range of design criteria and requires input from static and dynamic perspective. To date, this is the best methodology to yield the optimum sand control.

SPE 106018, April 2007
This paper was presented at the 2007 SPE Production and Operations Symposium held in Oklahoma City, Oklahoma, USA, 31 March-3 April

Title: ICD Screen Technology Used To Optimize Waterflooding in Injector Well

Authors: Raffn, A.G., Hundsnes, S., Kvernstuen, S., Moen, T.

Contribution to the understanding of sand control concept selection: This paper highlights the use sand controlled screens with integrated flow control devices for open-hole completed water injectors. It discusses the risk of erosion and plugging on the screens caused by the irregular flow distribution due to large permeability variation in the formation.

Objective of the paper: To present an innovative completion with sand control and inflow control devices to improve water injection profiles in various sand formation zones. It is modelled and tuned using reservoir stimulations.

Methodology used: The completion consists of wire-wrapped sand screen with inflow control device. The test was to understand flow and erosion on injector wells with screens and ICD. Flow is based on Bernoulli equation:

$$\Delta P = \rho \frac{v^2}{2} \qquad v = \frac{q}{A}$$

Pressure drop is generated by fluid flow through the nozzles. The relationship above shows ICD is used to restrict and stimulate flow into high and low permeability zones respectively; providing a much inflow distribution of water into the permeable zones.

Conclusion reached: Stimulation runs identify the possibility of controlling injection rates into individual zones. This paper also highlights that ICD injector completion is significantly less influenced by permeability contrasts compared to a standard screen completion.

Comments: Nothing significant. However, the paper gives a good understanding that injected fluids prefers to flow into high permeability streaks; leading to early breakthrough and poor recovery that must be prevented

SPE 107539, June 2007
This paper was presented at the 2007 European Formation Damage Conference held in Scheveningen, The Netherlands, 30 May-1 June

Title: Successful Installation of Stand Alone Sand Screen in More Than 200 Wells – The Importance of Screen Selection Process and Fluid Qualification

Authors: Mathisen, A.M., Aastveit, G. L., Alterås, E.

Contribution to the understanding of sand control concept selection: This paper highlights the failure of active sand control caused by long shale sections, high content of fine material and incompatibility of completion fluids to the formation.

Objective of the paper: To recommend a practice based on comprehensive screen selection by testing and ranking of different screen designs. The study includes a fluid qualification process by ensuring the drilling and completion fluid is compatible during the sand screen installation.

Methodology used:

1) Sand retention and screen plugging testing were used to rank the screen designs as part of the sizing selection. Data for the tests were collected from the formation’s weakest and poorest uniformity/sorting coefficients. The preparation of the data was originally from sand failure studies and particle sand distribution (PSD). The PSD analysis was plotted using dry sieve analysis and quality checked with Laser Particle Size Analysis (LPSA). Wire-Wrapped, Premium and Expandable screens were used for the tests.

2) Geological evaluation on the reservoir heterogeneity was used to identify shale sections between the core and the planned well path. The outcome of the evaluation determines the number of blank pipers and/or packers required to isolate unstable shale sections.

3) Inflow control technology was recommended to minimise annular flow. This phenomena transports particles in the annular hence increases the risk of screen plugging. The paper highlights the use of inflow control device (ICD) to reduce annular flow and provide a uniform inflow profile across the horizontal section of a well. Blank pipes and packers are also used to reduce annular flow.

Conclusion reached: Sand retention and plugging studies shows Premium screens has the lowest pressure drop combined with high sand retention and permeability. Inflow control technology and isolation devices are recommended for formations with long shale sections and/or high content of fine material.

Comments: This paper provides a comprehensive ranking on various screen designs using formation sand properties. It highlights the importance of sand retention and screen plugging even though it is conducted only at laboratory conditions. The paper also gives a brief justification of using inflow control technology and isolation devices as part of the sand control selection.

SPE 112283, February 2008
This paper was presented at the 2008 Formation Damage Control held in Lafayette, Louisiana, 13-15 February 2008

Title: Equalization of the Water Injection Profile of a Subsea Horizontal Well: A Case History

Authors: Amaral, A. S., Augustine, J., Henriksen, K., Rodrigues, V.F., Steagal, D.E., Paixão, L.C.A., Barbosa, P.

Contribution to the understanding of sand control concept selection: This paper focuses on the installation of water injector well with a lower completion system that incorporates both premium sand control screens and profile equalization. A schematic of the injector completion details was presented.

Objective of the paper: To create a uniform outflow profile in sand controlled completions for subsea horizontal water injectors.

Methodology used: Sand controlled completions such as standalone screens do not provide equalization of the water injection profile. An open-hole gravel pack provides some equalization but is affected by cost, risk and complexity.

Water injector well locations were defined and reservoir stimulation with desired injection rates was achieved. The stimulation shows uniform injection is required along the horizontal section. This is to prevent water-fingering and early breakthrough. Injection profiles at various injection rates were therefore stimulated. Severe imbalance of water influx into the reservoir was observed at the heel section of the horizontal water injector when non-equalizing sand controlled completion was used. Completion with screens and equalization provides a much better distribution of injected water into the horizontal section (i.e. heel to toe) of the well.

Conclusion reached: The use of equalization, screens and isolation packers enhances and improves water injection profile. It eliminates the chance of annular flow occurring.

Comments: This paper highlights inflow control devices can be used with sand controlled screens if equalize outflow profile is required in a water injector well. However, the findings are based only on a subsea horizontal well.

SPE 114781, October 2008
This paper was presented at the 2008 SPE Asia Pacific Oil & Gas Conference and Exhibition held in Perth, Australia, 20-22 October

Title: Sand Management: What Are We Sure Of?

Authors: Slayter, A. G., Byrne, M., McPhee, C. A., McCurdy, P.

Contribution to the understanding of sand control concept selection: This paper highlights best practice on several design criteria for openhole wells that require sand control. Rock mineralogy, particle size distribution (PSD), screen-to-openhole annulus, screen failure mechanisms and screen collapse/ buckling are the design criteria discussed.

Objective of the paper: To propose a systematic framework to address critical design criteria in a timely and ordered manner. Sand control design criteria usually tangled with more than one objective.

Methodology used:

1) **Rock mineralogy** study: Used X-Ray Diffraction (XRD) to identify the presence and type of clays. Cation Exchange Capacity (CEC) is used to measure the reactivity of shale (i.e. swelling of clays). Dynamic Flow through Test (DTTT) is part of the study to assess the clay behaviour when fluids are circulated at high rates through a core sample. This study is important to determine the compatibility of water-based mud (WBM) for gravel water packs.

Table B-4: Typical CEC values for specific clays

Type & Behaviour of Clay	CEC meq/100g)
Swelling Smectites	80-150
Mobile Kaolinites	1-10

2) **PSD** study: Laser Particle Sieve Analysis must be performed on top of the dry sieve analysis. This is to quality check the particle size distribution from both techniques. Fines are its ability to move between pores of a rock. Rock grain sizes smaller than 325mesh (44μm) are categorised as fines. The 44 μm cut-off is based on the finest sand screen available to date. Fines greater than 10% is a concern for all sand control options. The study recommends wellbore enlargement and this proposal is consistent with Tiffin's criteria.
3) **Screen-to-Openhole** Annulus study shows annular removal is necessary to prevent flow behind the pipe. This will prevent screen erosion and plugging caused by hot spots and fine particles respectively. Flow in the annular can be prevented by using inflow control devices (ICD) and expandable annular packers. Significant cost reduction as opposed to wellbore enlargement. The presence of annular can also be removed by using ESS.
4) **Screen failure mechanisms** are plugging and erosion. Critical erosion velocities are. Determined. Allowable critical flow rates for both liquid and gas flow are tabulated below. This is based on consolidation from various operators:

Table B-5: Critical flux rates to avoid erosion for various sand control completions

Sand Control Screen System	Critical V for Liquid (ft/s)	Critical V for Gas Flow (ft/s)	Company
Expandable Sand Screen (ESS)	1	1	Weatherford
Wire Wrapped Screen (WWS)	1	6	US Filter, Johnson Screen
Woven and Wire Wrapped Screen	1	Not available	Shell
Cased Hole Gravel Pack (CHGP)	10	20	BP

5) **Screen collapse/ buckling** can occur when screen is plugged. This can be mitigated if the well is bean up slowly after being idle for unknown period of time. The presence of shale is the likely cause of screen plugging because shale is unstable and brittle. It will weaken and collapse onto sand screen. This increases the likelihood of screen failure.

Conclusion reached: Successful sand management requires an organised approach when executing all design selection criteria. The use of ICDs and packers must be evaluated as part of a continuous approach in developing optimum sand control system.

Comments: The paper highlights additional information that is very useful in defining the selection criteria. More focus the critical design and limitation of sand control screens. Expandable sand screen (ESS) was introduced to remove annular space in the wellbore. Critical flow rates are useful to minimise screen erosion. Flow rates in the annulus can be lowered by installing flow control devices and isolation packers as part of the sand control completion.

SPE 128038, February 2010
This paper was presented at the 2010 SPE International Symposium and Exhibition on Formation Damaged held in Perth, Australia, 20-22 February.

Title: Improved Selection Criteria for Sand Control – When Are “Fines” Fines?

Authors: Byrne, M., Slayter, A. G., McCurdy, P.

Contribution to the understanding of sand control concept selection: This paper highlights new definition of fines. This is to ensure an optimum and tailored sand control is selected. A modified sand control selection process to account the new definitions is proposed in this paper.

Objective of the paper: To provide a discussion on fines. It explains how fines should be measured, classified and interpreted. The paper also reviews previous published literature on fines and existing sand control selection guidelines.

Methodology used: Initial review shows conventional guidelines used in determining sand control systems were Schwartz (1969) and then Tiffin *et al.* (1998). Both of the methodology with some additional guidelines were consolidated and integrated into a flowchart. The definition of fines as “less than 44 μm” is inappropriate for sand control selection in very fine grained rocks because it may have a high percentage of “less than 44 μm fraction”. The new definition of fines is presented in the left flowchart below. With the modified definition of fines, the right flowchart presents an enhanced sand control selection process:

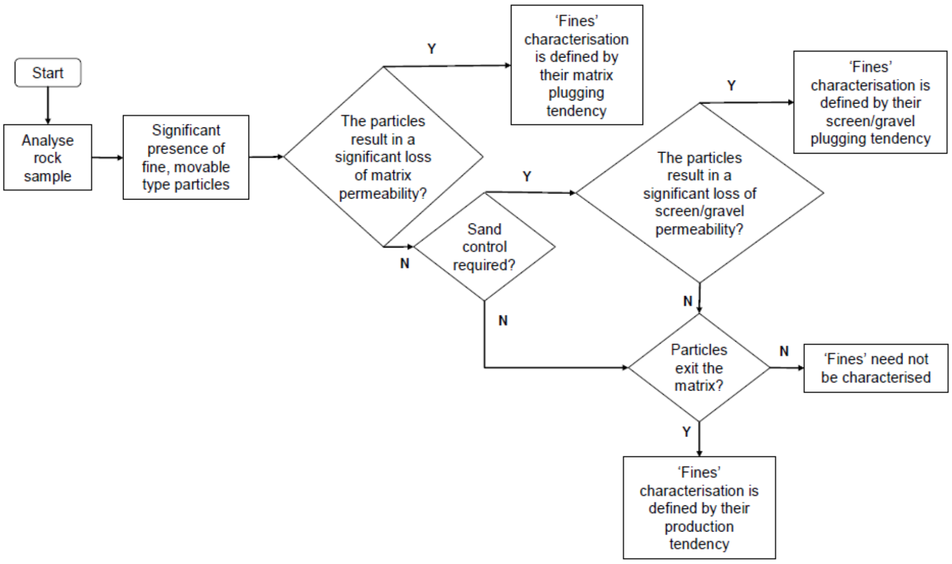

Figure B-2: Definition of fines

Conclusion reached: The paper highlights the meaning of “fines” from an engineering perspective. It redefines fine from being “less than 44μm” to “to be considered as part of the rock that can move through the pores of intact rock”. A clear distinction is made between fines moving in intact rock and fines present in the rock that collapsed between the formation face and the sand control completion.

Comments: This paper provides an engineering view of defining fines for sand control. The flowcharts are useful to find the true meaning of fines during the sand control selection. It is useful because if the formation fails and deposit into the annulus, the sizing of fines will be different and further study will be required.

SPE 137057, November 2010
This paper was presented at the 2010 Abu Dhabi International Petroleum Exhibition & Conference held in Abu Dhabi, UAE, 1-4 November.

Title: Optimizing Injection Wells through Innovative Completion

Authors: Khalil, A., Elasmar, M., Shafie, S.

Contribution to the understanding of sand control concept selection: None. However, the inclusion of inflow control to achieve uniform injection profile in water injectors is required.

Objective of the paper: To share its application of influx control device (ICD) for an injector well for in a carbonate formation. The completion shows an intelligent wellbore completion that gives an even distribution of injected water along the wellbore (heel to toe).

Methodology used: Initial review shows heel-to-toe effects, permeability contrasts and existence of fracture thieves are causes of imbalance water injection profile into the reservoir. Stimulation was modelled to estimate the water injection distribution. Case A and Case B were run. Case A is a barefoot (no inflow control) completion. Case B is a completion completed with inflow control. Study was conducted on both cases using a wellbore hydraulics stimulator.

The requirement injection split ratio into the reservoir is 40% (heel):60% (toe). The barefoot completion (Case A) failed to honour the requirement split ratio. Most of the water injected took the path of least resistance and flowed into the high permeability zones, located near the heel section of the well. Sensitivity runs was conducted for Case B to achieve the optimized completion. The optimized completion indeed honoured the design injection split ratio. It provided a much better distribution of injected water from the heel to the toe section of the well.

Injection log was then conducted and the injected split ratio with the optimized completion was 44% (heel):56% (toe); closed to the design requirement modelled in the wellbore hydraulic stimulator

Conclusion reached: Most of the injected water will take the path of least resistance and flow into a higher permeable zone; causing early water breakthrough and poor reservoir sweep of the oil.

Comments: This paper provides a good background on how to model and optimize inflow control devices with sand controlled completion in a wellbore hydraulic stimulator.

APPENDIX C: NOMENCLATURE

ΔP	Pressure Drop [psi]
APT	Alternate Path Technology
BHT	Bottom Hole Temperature
CEC	Cation Exchange Capacity
DIF	Drill-In Fluids
DSA	Dry Sieve Analysis
ECD	Equivalent Circular Density
ESS	Expandable Sand Screen
FG	Fracture Gradient
FMI	Formation Image Logs
GP	Gravel Pack
HRWP	High Rate Water Pack
ICD	Inflow Control Device
ICV	Inflow Control Valves
ID	Internal Diameter
LPSA	Laser Particle Sieve Analysis
NAF	Non Aqueous Fluid
NNW	North-North West Direction
NTG	Net to Gross [%]
OBM	Oil Based Mud
OD	Outer Diameter
P_{frac}	Fracture Opening Pressure [psia]
PLT	Production Logging Tool
PP	Pore Pressure
PSD	Particle Size Distribution
PPS	Pre Packed Screen
RQI	Rock Quality Index
SAS	Standalone Screen
SCS	Sand Control Selection
SOBM	Synthetic Oil Based Mud
SRT	Sand Retention Test
SSE	South-South East Direction
WBM	Water Based Mud
WC	Wellbore Condition
WI	Water Injector
WWS	Wire Wrapped Screen

APPENDIX D: METHODOLOGY

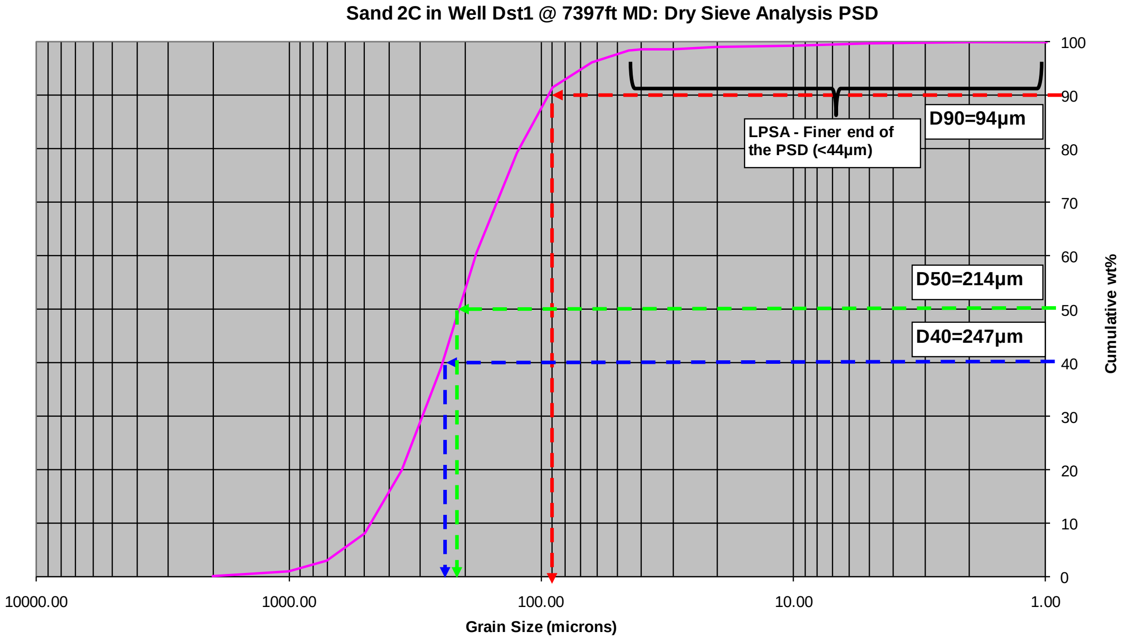

Figure D-1: PSD for Sand 2C in Well Dst1

Table D-1: Sand Control Selection Table for various types of Standalone Screens (SAS)

SAS	Preferred	Acceptable	Use With Caution	Not Recommended
WWS (All critical concerns combined)	Low Fracture Gradient	High Rugosity/Severe Washout	Deviation 0-55^{o}	Prone to fines migration
	High Leakoff Concerns	Deviation 55^{o}-75^{o}	NTG < 60-80%	Use of breakers
	Small Bore Hole ID < 6"	High production rate	Multiple oil bearing zones isolated by non-productive	
	Drill with OBM	High frequency of well intervention	High Variable Permeability/ Lamination	
	Drill with WBM/ SOBM	Risk of installing equipment		
	Unstable/ Reactive shale	Equipment lifespan/ reliability		
	High static BHT			
	Horizontal length 0 - 4000ft, >4000ft			
	High depleted reservoir			
	Cost effectiveness			
Pre-packed (All critical concerns combined)	Low Fracture Gradient	High Rugosity/Severe Washout	Deviation 0-55^{o}	Prone to fines migration
	High Leakoff Concerns	Deviation 55^{o}-75^{o}	NTG < 60-80%	Use of breakers
	Small Bore Hole ID < 6"	High production rate	Multiple oil bearing zones isolated by non-productive barriers	
	Drill with OBM	High frequency of well intervention	High Variable Permeability/ Lamination	
	Drill with WBM/ SOBM	Risk of installing equipment	Equipment lifespan/ reliability	
	Unstable/ Reactive shale	Cost effectiveness		
	High static BHT			
	Horizontal length 0 - 4000ft, >4000ft			
	High depleted reservoir			
Premium (All critical concerns combined)	Low Fracture Gradient	Deviation 55^{o}-75^{o}	Prone to fines migration	Use of breakers
	High Leakoff Concerns	High frequency of well intervention	Deviation 0-55^{o}	
	Small Bore Hole ID < 6"	Risk of installing equipment	NTG < 60-80%	
	High Rugosity/Severe Washout	Cost effectiveness	Multiple oil bearing zones isolated by non-productive	
	Drill with OBM		High Variable Permeability/ Lamination	
	Drill with WBM/ SOBM			
	Unstable/ Reactive shale			
	High static BHT			
	Horizontal length 0 - 4000ft, >4000ft			
	High depleted reservoir			
	High production rate			
	Equipment lifespan/ reliability			

Table D-2: Sand Control Selection Table for Expandable Sand Screens (ESS)

Expandable Sand Screen (ESS)	Preferred	Acceptable	Use With Caution	Not Recommended
Wellbore Critical Concerns	Low Fracture Gradient	Prone to fines migration	High Rugosity/Severe Washout	
	High Leakoff Concerns		Use of breakers	
	Small Bore Hole ID < 6"		Unstable/ Reactive shale	
	Drill with OBM			
	Drill with WBM/ SOBM			
	High static BHT			
Reservoir Critical Concerns	Horizontal length 0 - 4000ft, >4000ft	Deviation 55^{o}-75^{o}	Deviation 0-55^{o}	
	High depleted reservoir	NTG < 60-80%		
		Multiple oil bearing zones isolated by non-productive barriers		
		High Variable Permeability/ Lamination		
Operation Critical Concerns	High production rate			
	High frequency of well intervention			
	Risk of installing equipment			
	Equipment lifespan/ reliability			
	Cost effectiveness			

Table D-3: Sand Control Selection Table for OHGP-LAWP/ HAWP

OHGP-LAWP/ HAWP	Preferred	Acceptable	Use With Caution	Not Recommended
Wellbore Critical Concerns		Small Bore Hole ID < 6"	Low Fracture Gradient	Drill with OBM
		Drill with WBM/ SOBM	High Leakoff Concerns	
		High static BHT	High Rugosity/Severe Washout	
			Prone to fines migration	
			Use of breakers	
			Unstable/ Reactive shale	
Reservoir Critical Concerns	Deviation 0-55^{o}	High Variable Permeability/ Lamination	Deviation 55^{o}-75^{o}	Horizontal length > 4000ft
	Horizontal length 0 - 1000ft		Horizontal length 1000 - 4000ft	
	NTG < 60-80%		Multiple oil bearing zones isolated by non-productive	
			High depleted reservoir	
Operation Critical Concerns	High production rate	Cost effectiveness	Risk of installing equipment	
	High frequency of well intervention			
	Equipment lifespan/ reliability			

Table D-4: Sand Control Selection Table for OHGP-Slurry Pack

OHGP-Slurry Pack	Preferred	Acceptable	Use With Caution	Not Recommended
Wellbore Critical Concerns	Low Fracture Gradient	Drill with WBM/ SOBM	Small Bore Hole ID < 6"	
	High Leakoff Concerns		High static BHT	
	High Rugosity/Severe Washout			
	Drill with OBM			
	Prone to fines migration			
	Use of breakers			
	Unstable/ Reactive shale			
Reservoir Critical Concerns	Deviation 55^{o}-75^{o}	Deviation 0-55^{o}	Horizontal length > 4000ft	
	Horizontal length 0 - 4000ft	High Variable Permeability/ Lamination		
	NTG < 60-80%			
	Multiple oil bearing zones isolated by non-productive barriers			
	High depleted reservoir			
Operation Critical Concerns	High production rate	Cost effectiveness	Risk of installing equipment	
	High frequency of well intervention			
	Equipment lifespan/ reliability			

APPENDIX E: CASE STUDY BACKGROUND

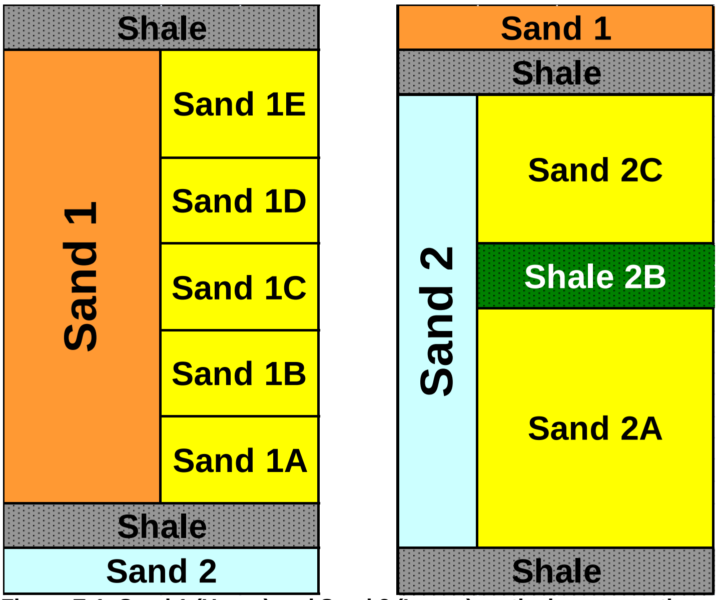

Figure E-1: Sand 1 (Upper) and Sand 2 (Lower) vertical cross-sections.

Table E-1: Data from appraisal wells used for the case study

#	Field	Formation	Proposed WI	SCAL	Wireline Logs	PVT	Well Test	XRD
				Wells				
1	Area B	Sand 2	I2a	A, Ast1	A, Ast1	A	A	
2	Area C	Sand 2	I2b	B	B, Bst1, F	B	-	
3	Area A	Sand 1	I1a	Ast1, Est1	Ast1, Est1	C, D, Est1	C, D	C, Cst1, Cst3
4	Area A	Sand 1	I1b	C, Cst1, Cst3	C, Cst1, Cst2, Cst3	C, D, Est1	C, D	C, Cst1, Cst3
5	Area A	Sand 1	I1c	C,Cst3,D,Dst1	C, Cst3, D, Dst1	C, D, Est1	C, D	Dst1, Est1
6	Area A/ Area B	Sand 1/ Sand 2	I1/I2	C,Cst3,D,Dst1	C, Cst3, D, Dst1	C, D, Est1	C, D	Dst1, Est1

Table E-2: Design injection requirement for the water injectors

#	Field	Formation	Proposed WI	Reservoir P (psia)	Design injection capacity (stbw/d)	Minimum WH Injection P (psi)	Fracture Injection P (psi)
1	Area B	Sand 2	I2a	3236	50, 000	4000	6200
2	Area C	Sand 2	I2b	3335	50, 000	4000	6200
3	Area A	Sand 1	I1a	3191	20, 000-50, 000	4000	6200
4	Area A	Sand 1	I1b	3191	20, 000-50, 000	4000	6200
5	Area A	Sand 1	I1c	3191	20, 000-50, 000	4000	6200
6	Area A/ Area B	Sand 1/ Sand 2	I1/I2	3191/ 3236	50, 000	4000	6200

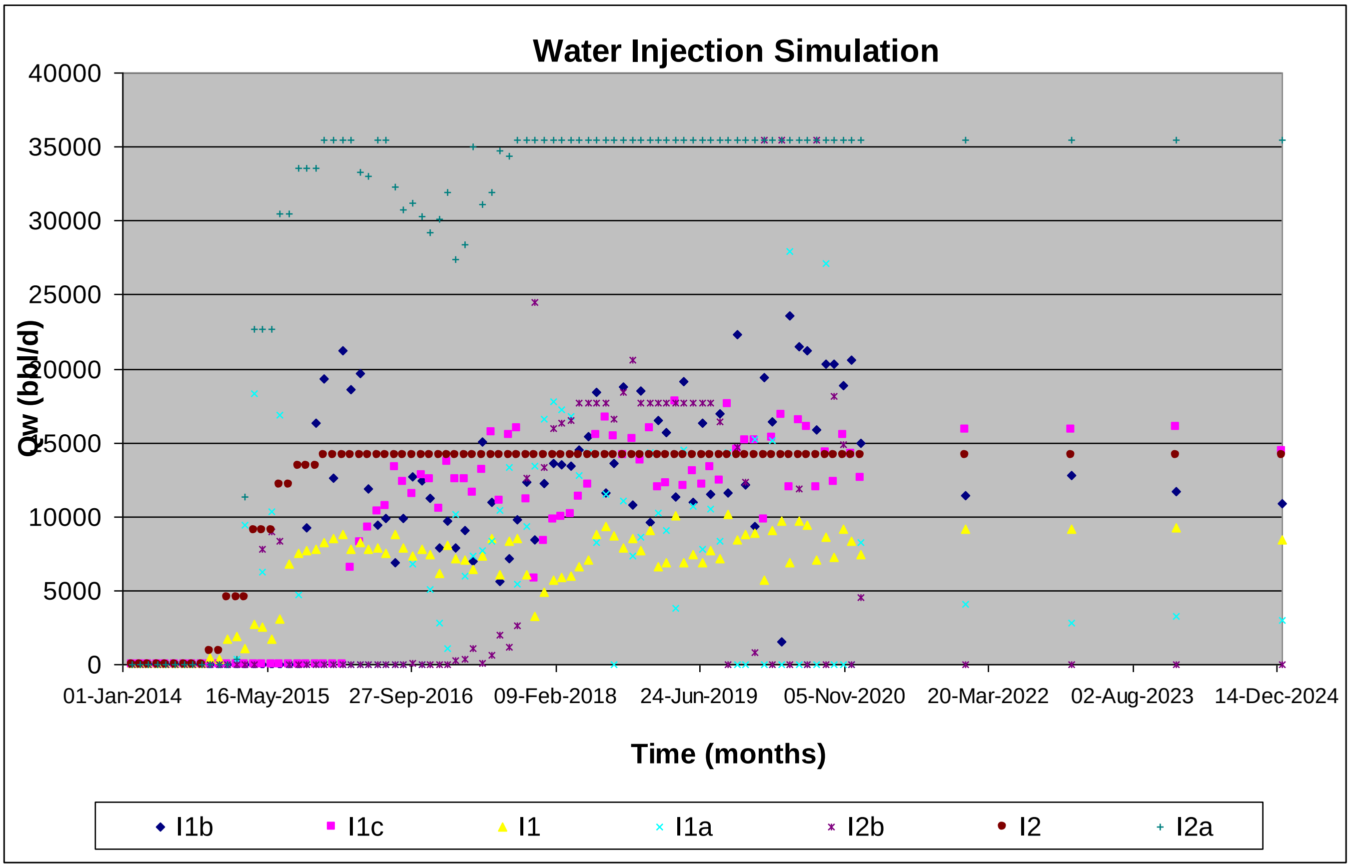

Figure E-2: Reservoir stimulation shows six wells water injection rates for the first 11 years (Beesley *et al.* 2011).

APPENDIX F: SANDING FAILURE PREDICTION

Overburden (Vertical) (σ_v) Stress Gradient

σ_v (psi) = 1.16×10^{-5} TVDSS^2 (ft) + $0.941 \times$ TVDSS (ft)-354…………………………………………………………Eq.F-1

The equation above was calculated by integrating the density-log data of Wells A and Ast1. It was then compared with Wells C, F and E. Comparison was similar indicating the equation above is valid for the case study. Therefore, the σ_v gradient remains approximately at 0.95 psi/ft.

Minimum Horizontal Stress Gradient

σ_h (psi) = 1.59×10^{-6} TVDSS^2 (ft) + $0.785 \times$ TVDSS (ft)-316……………………………………………......…………... Eq.F-2

The equation above is derived from previous work FIT/ LOT of several wells from a nearby field. Values obtained from the equation shows similarities with the injectivity test conducted on Well D:

Maximum Horizontal Stress Gradient

σ_H (psi) = 1.71×10^{-6} TVDSS^2 (ft) + $0.848 \times$ TVDSS (ft)-341…………………………………...………......………... Eq.F-3

σ_H gradient is assumed to have the same form as σ_h gradient (taking σ_H/σ_h=1.08):

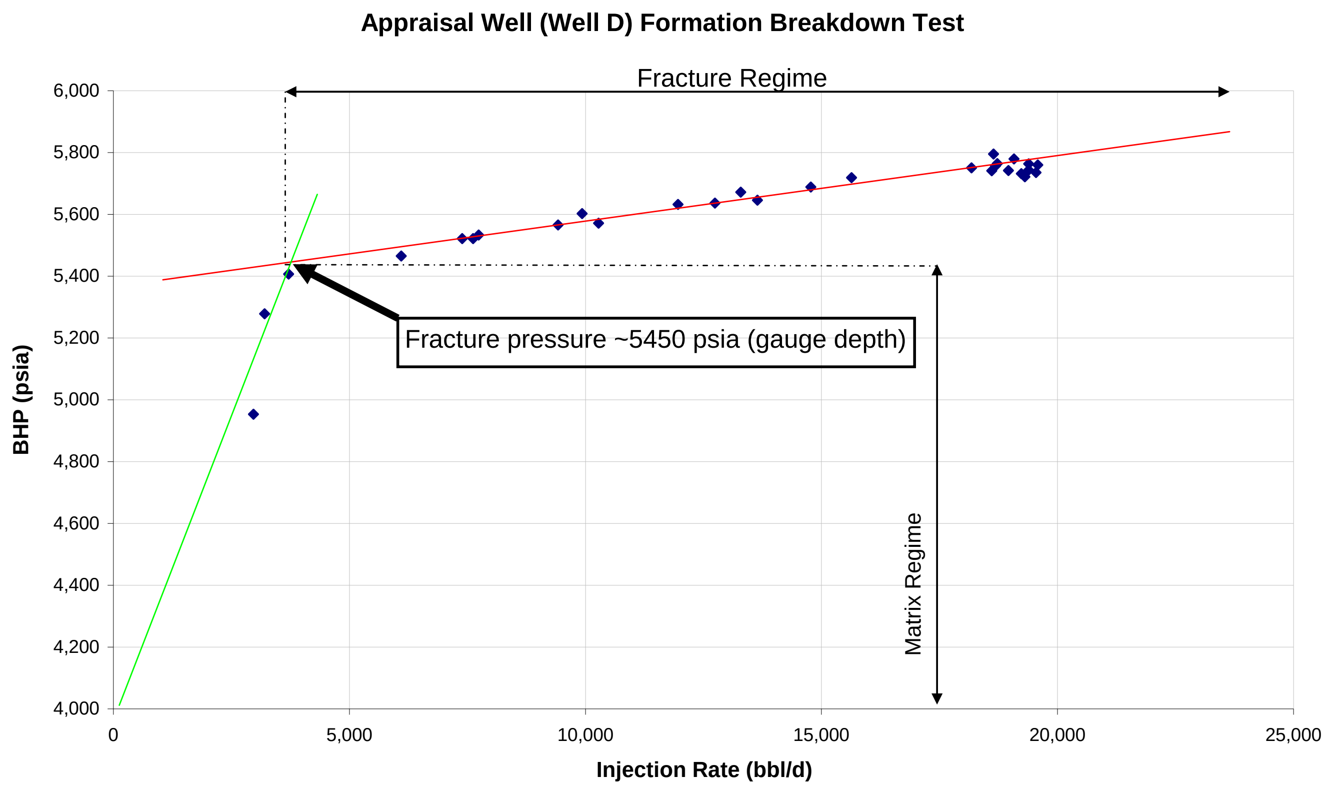

Figure F-1: Fracture opening pressure of 5450psi (Sand 1D in Reservoir 1).

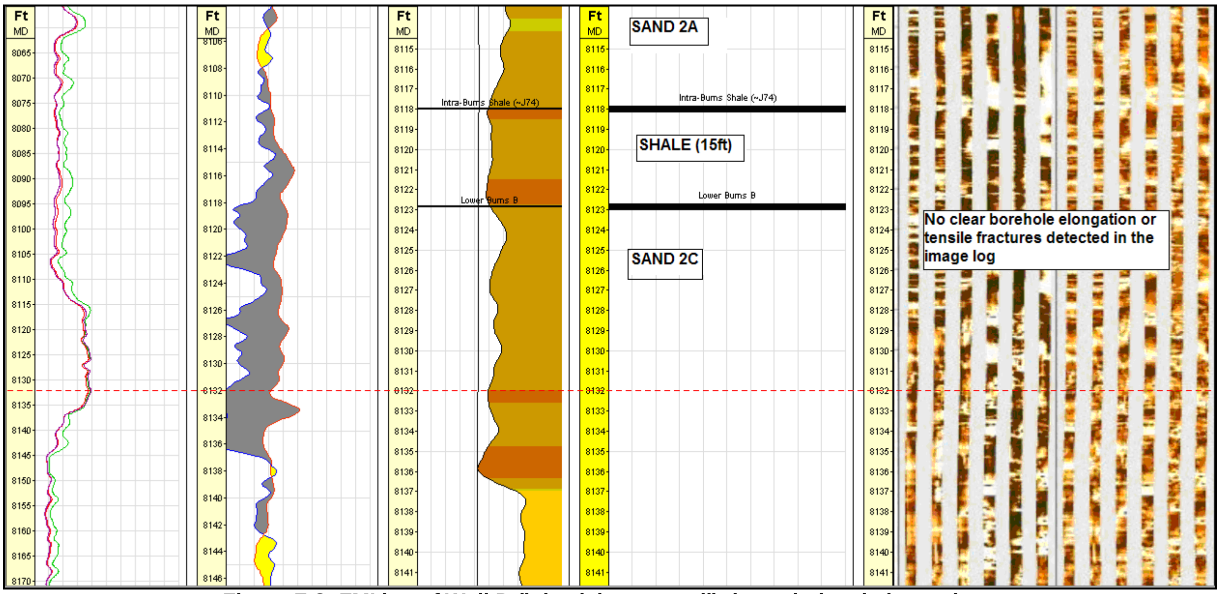

Figure F-2: FMI log of Well D (injectivity test well) through the shale section.

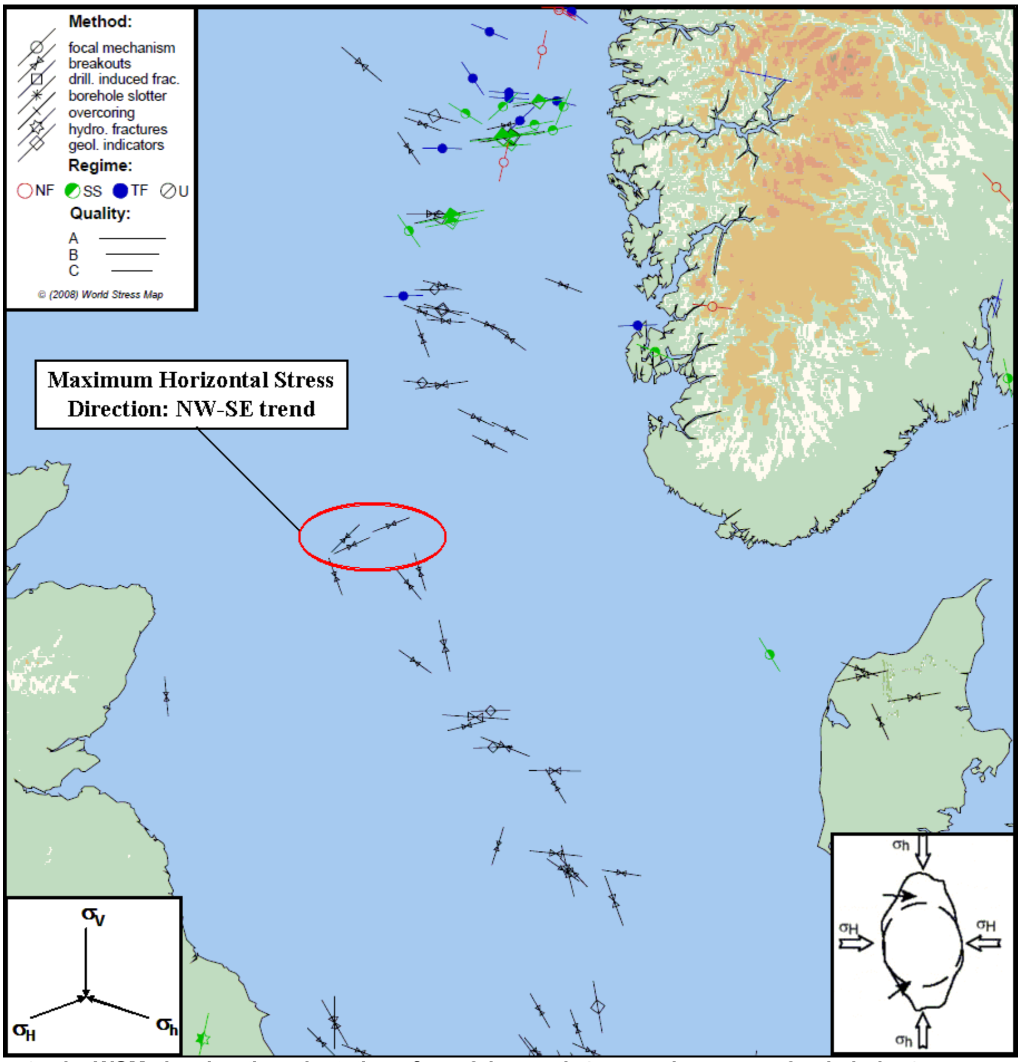

Figure F-3: The WSM showing the orientation of σ_H of the North Sea, UK (*courtesy of Helmholtz Centre Potsdam*).

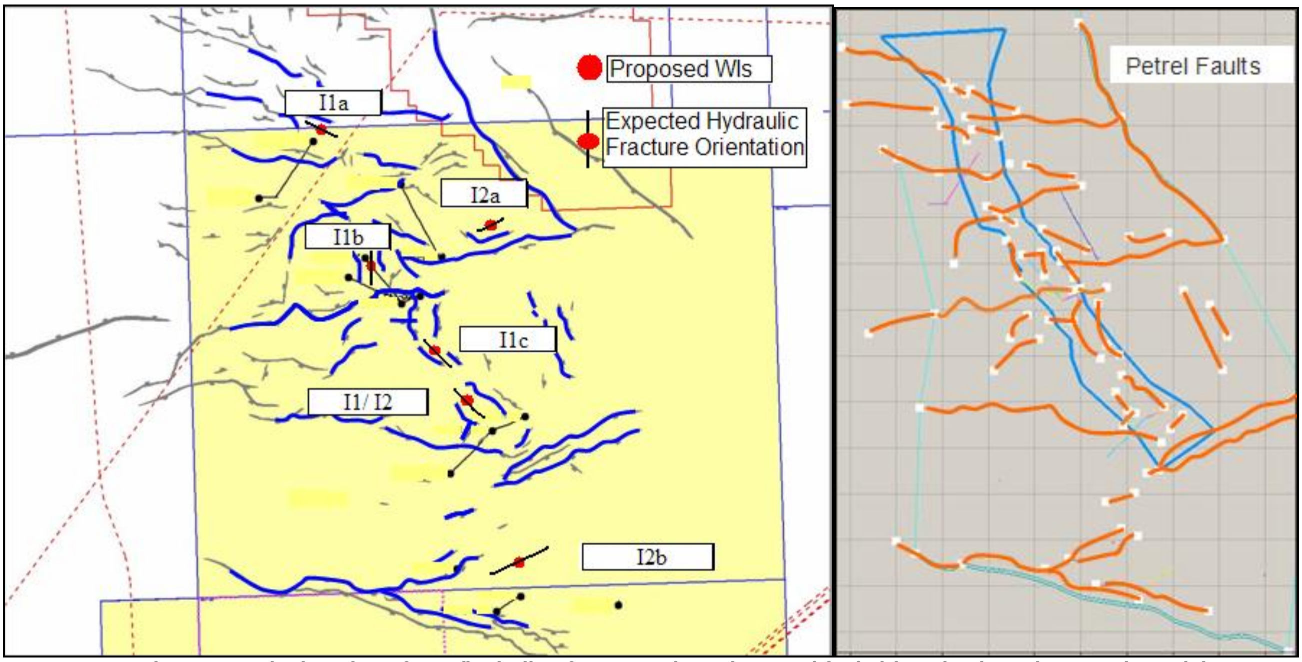

Figure F-4: The location of WIs (including fracture orientations and faults) in seismic and reservoir models.

Table F-1: Expected hydraulic fracture orientation of the water injectors

Proposed WIs	Expected Hydraulic Fracture Orientation (Degrees Azimuth)
I1/I2	045°N and 135°N
I1a	060°N and 120°N
I1b	010°N and 190°N
I1c	045°N and 135°N
I2a	065°N and 245°N
I2b	065°N and 245°N

APPENDIX G: PARTICLE SIZE DISTRIBUTION

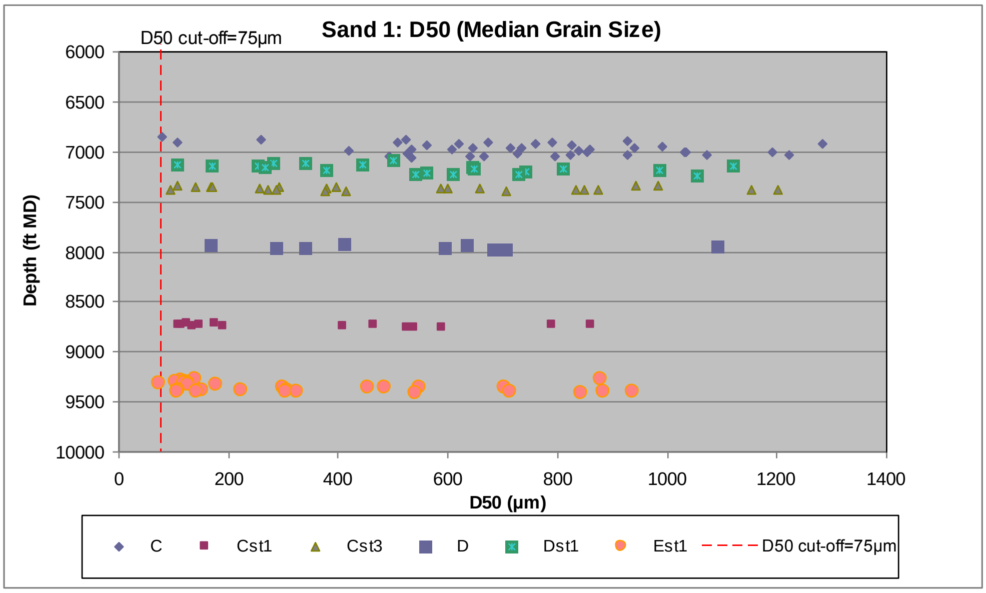

Figure G-1: D50 distribution for Sand 1

Table G-1: D50 minimum, average and maximum values derived from PSD of Sand 1 DSA

D50	Sand 1 (µm)		
Well	Min	Average	Max
C	80	730	1284
Cst1	108	370	861
Cst3	93	531	1201
D	169	541	1093
Dst1	106	559	1119
Est1	72	360	938
Average	**105**	**515**	**1083**

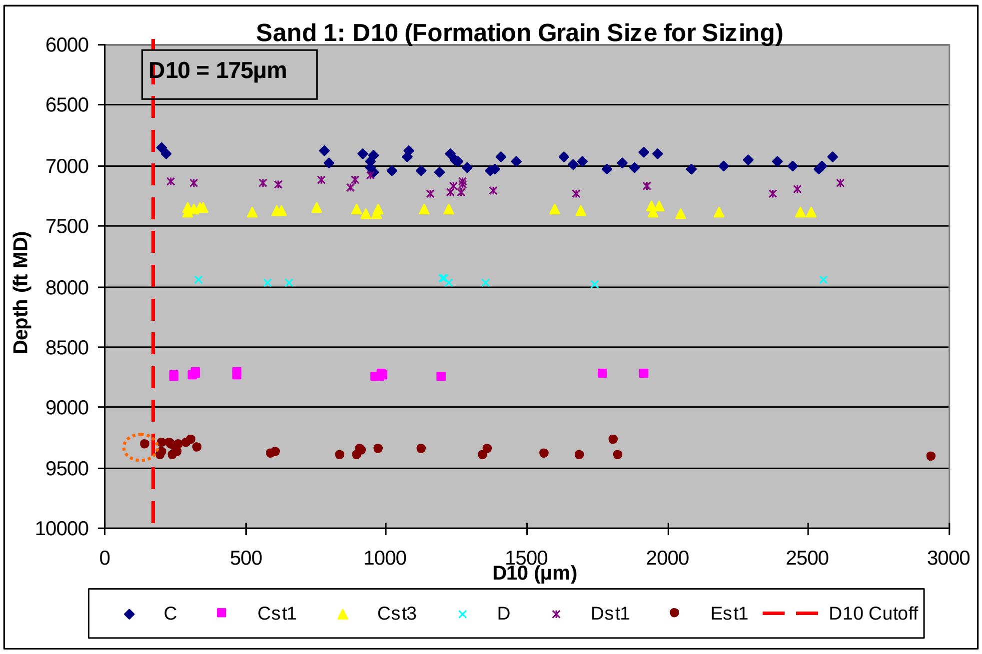

Figure G-2: D10 distribution for Sand 1

Table G-2: D10 minimum, average and maximum values derived from PSD of Sand 1 DSA

D10	Sand 1 (µm)		
Well	Min	Average	Max
C	200	1481	2588
Cst1	248	804	1922
Cst3	292	1190	2508
D	331	1205	255
Dst1	232	1253	2611
Est1	149	808	2938
Average	**242**	**1124**	**2137**

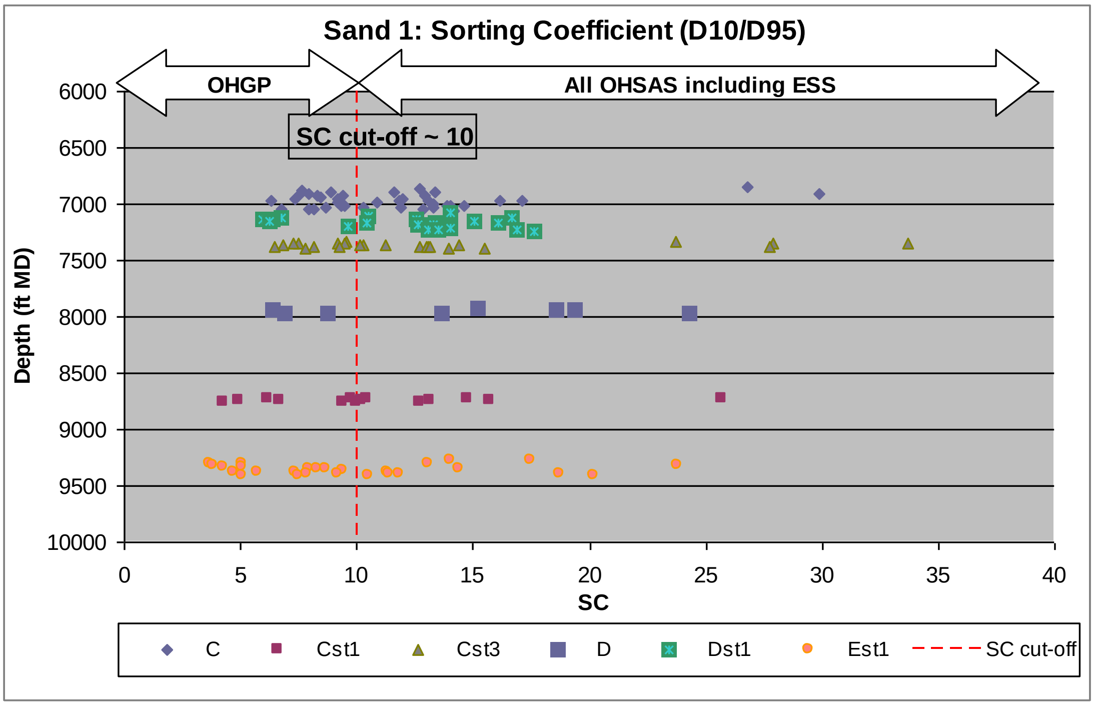

Figure G-3: Sc of Sand 1

Table G-3: Sc (D10/D95) minimum, average and maximum values derived from PSD of Sand 1 DSA

Sc (D10/D95)	Sand 1 (µm)		
Well	Min	Average	Max
C	6	12	30
Cst1	4	11	26
Cst3	7	13	34
D	6	14	24
Dst1	6	12	18
Est1	4	10	24
Average	**6**	**12**	**26**

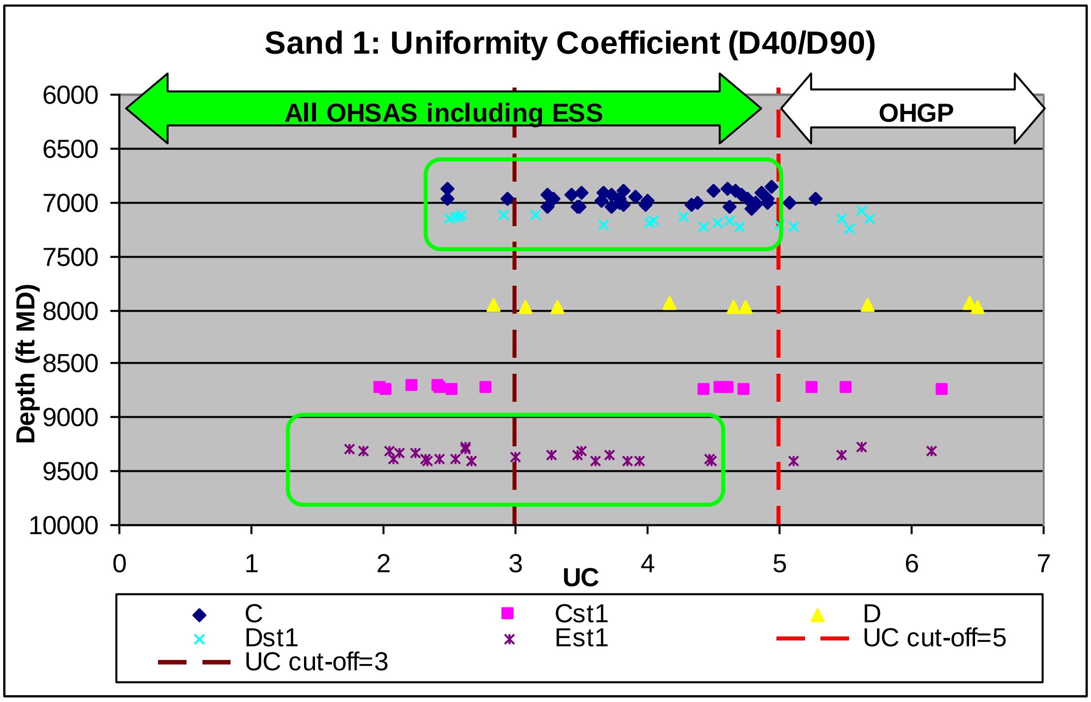

Figure G-4: Uc vs. depth for Sand 1

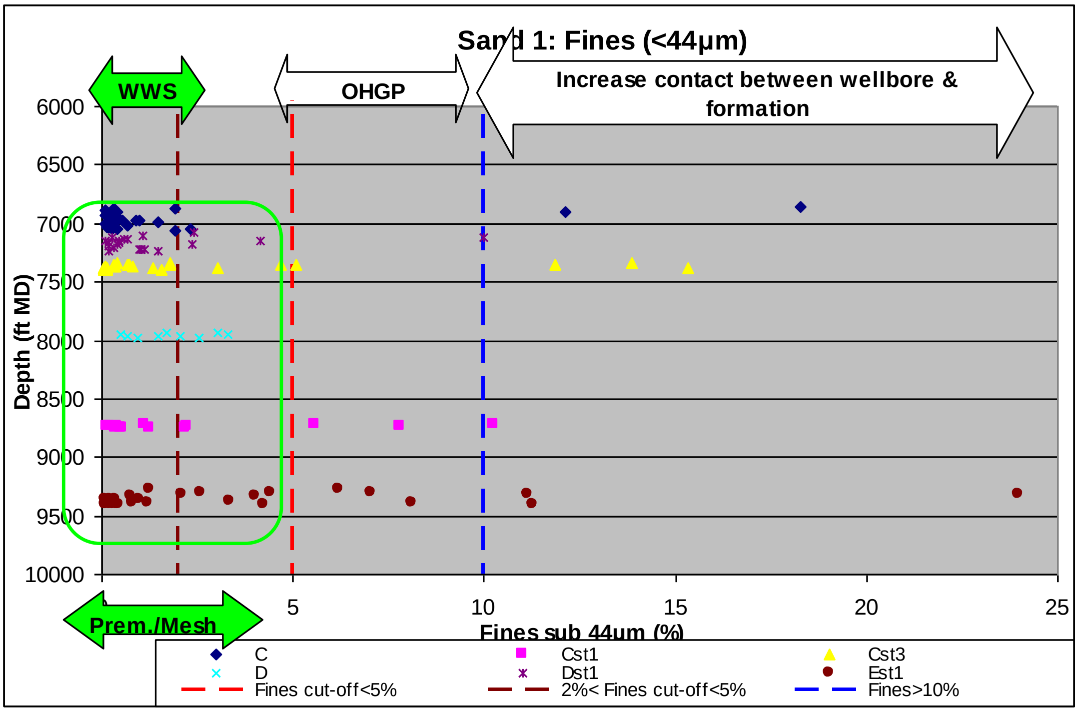

Figure G-5: Formation fines (%) vs. depth for Sand 1

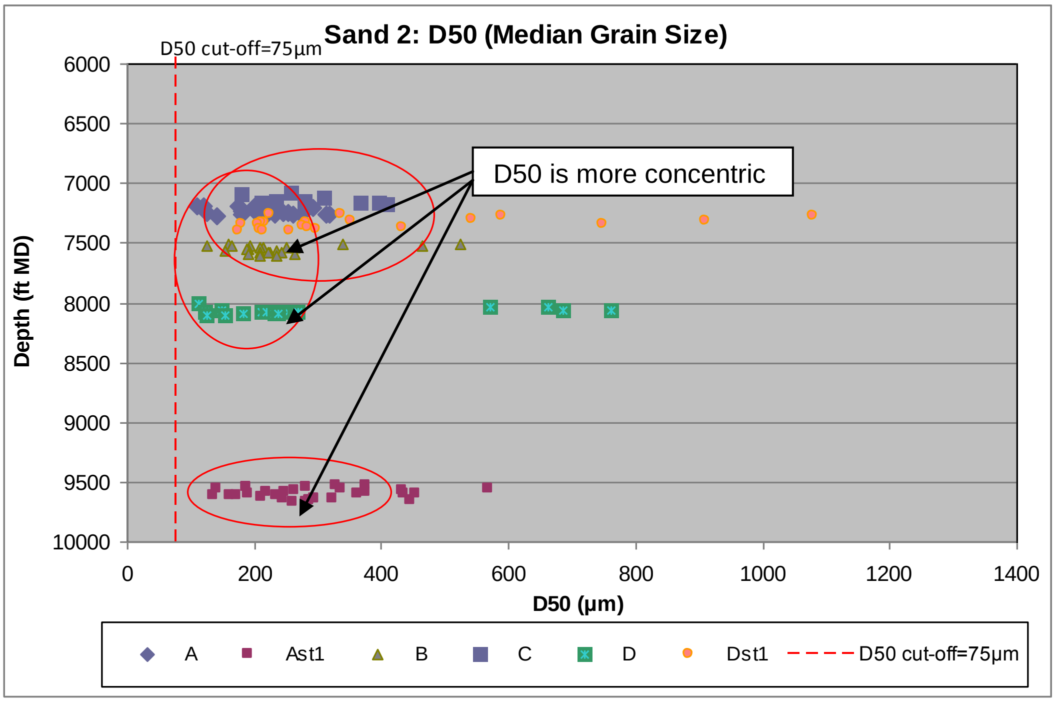

Figure G-6: D50 distribution for Sand 2

Table G-4: D50 minimum, average and maximum values derived from PSD of Sand 2 DSA

D50	**Sand 2 (µm)**		
Well	Min	Average	Max
A	110	215	318
Ast1	136	291	568
B	125	238	523
C	181	292	408
D	113	298	761
Dst1	174	382	1078
Average	**140**	**286**	**609**

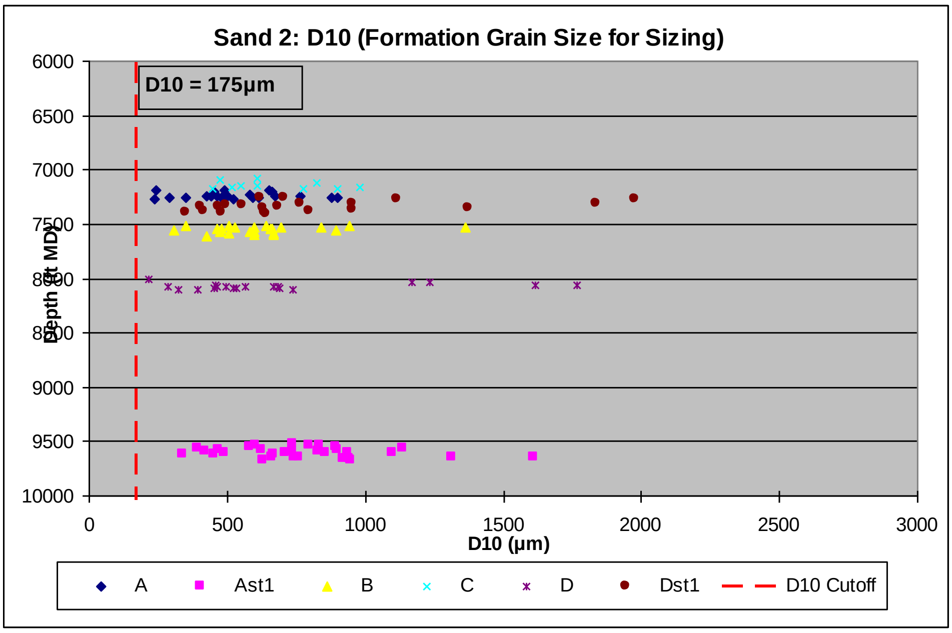

Figure G-7: D10 distribution for Sand 2

Table G-5: D10 minimum, average and maximum values derived from PSD of Sand 2 DSA

D10	**Sand 2 (µm)**		
Well	Min	Average	Max
A	237	531	899
Ast1	338	775	1612
B	109	628	1361
C	447	668	979
D	215	698	1769
Dst1	351	802	1928
Average	**283**	**684**	**1425**

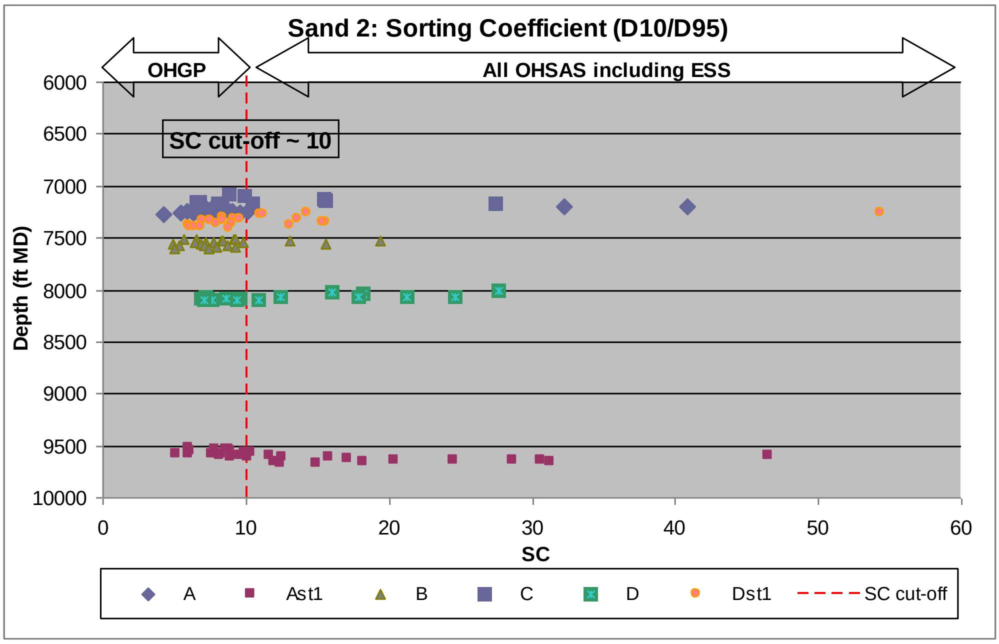

Figure G-8: Sc of Sand 2

Table G-6: Sc (D10/D95) minimum, average and maximum values derived from PSD of Sand 2 DSA

Sc (D10/D95)	**Sand 2 (µm)**		
Well	Min	Average	Max
A	4	10	41
Ast1	5	14	47
B	5	9	19
C	7	12	27
D	7	13	28
Dst1	6	12	54
Average	**6**	**12**	**36**

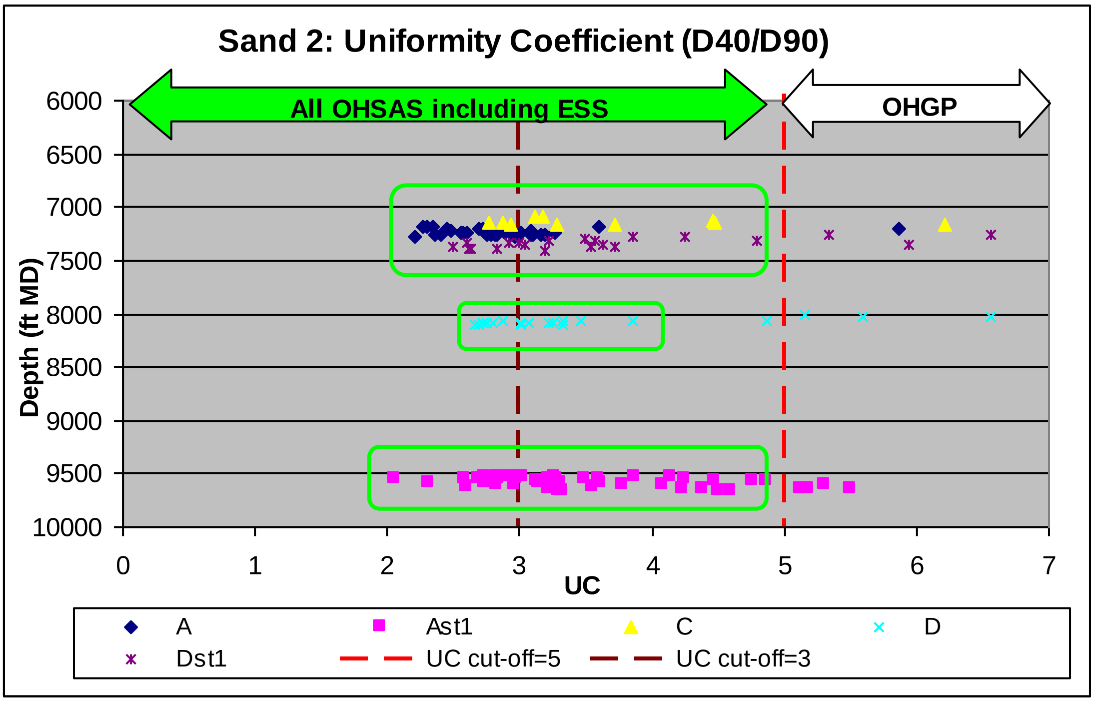

Figure G-9: Uc vs. depth for Sand 2

Figure G-10: Formation fines (%) vs. depth for Sand 2

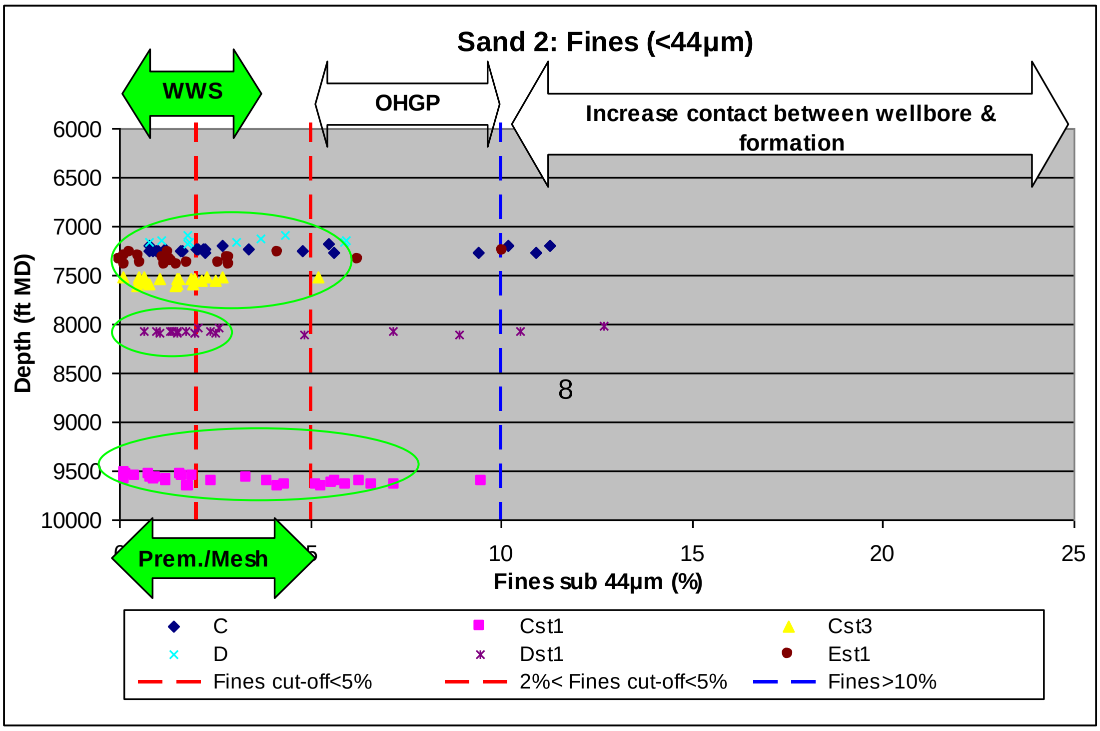

Table G-7: Recommended sand control strategy based on Flowchart B for each unit in Sands 1 and 2

Sand 1 Formation	Reservoir 1								
	Sand 1F (N/A)			Sand 1E			Sand 1D		
	Min	Mean	Max	Min	Mean	Max	Min	Mean	Max
D10 (µm)		942		149	693	1967	202	1120	2938
D50 (µm)		501		72	325	983	93	488	1201
UC (D40/D90)		5.6		2	4	8	2	4	6
SC (D10/D95)		14		4	13	34	5	11	28
Fines (sub44µm)		2.4		0.1	5	24	0.1	2	15
Recommended Sand Control (Flowchart)									
D10 (µm)		**SAS**		OHGP	**SAS**	SAS	SAS	**SAS**	SAS
D50 (µm)		**SAS**		OHGP	**SAS**	SAS	SAS	**SAS**	SAS
SC (D10/D95)		**OHGP**		SAS	**OHGP**	OHGP	SAS	**OHGP**	OHGP
UC (D40/D90)		**OHGP**		WWS	**Prem./ Mesh**	OHGP	WWS	**OHGP**	OHGP
Fines (sub44µm)		**Prem./ Mesh**		WWS	**Prem./ Mesh**	OHGP	WWS	**WWS**	OHGP

Sand 1 Formation	Reservoir 1								
	Sand 1C			Sand 1B			Sand 1A		
	Min	Mean	Max	Min	Mean	Max	Min	Mean	Max
D10 (µm)	220	1452	2588	580	1325	2371	798	1600	2548
D50 (µm)	107	692	1284	287	611	1053	419	812	1223
UC (D40/D90)	2.5	4.1	5.7	3.1	4.7	6.5	3.2	4.2	5.1
SC (D10/D95)	6	12	30	7	14	24	7	11	15
Fines (sub44µm)	0.1	1	12	0.2	1	3	0.1	0.5	2
Recommended Sand Control (Flowchart)									
D10 (µm)	SAS	**SAS**	SAS	SAS	**SAS**	SAS	SAS	**SAS**	SAS
D50 (µm)	SAS	**SAS**	SAS	SAS	**SAS**	SAS	SAS	**SAS**	SAS
SC (D10/D95)	SAS	**OHGP**	OHGP	SAS	**OHGP**	OHGP	SAS	**OHGP**	OHGP
UC (D40/D90)	WWS	**OHGP**	OHGP	WWS	**OHGP**	OHGP	WWS	**OHGP**	
Fines (sub44µm)	WWS	**WWS**	OHGP	WWS	**WWS**	Prem./ Mesh	WWS	**WWS**	WWS

Sand 2 Formation	Reservoir 2								
	Sand 2C								
	Min	Mean	Max	Min	Mean	Max	Min	Mean	Max
D10 (µm)	215	1004	1978	767	1185	1837	244	657	1769
D50 (µm)	113	510	1078	352	602	911	109	260	761
UC (D40/D90)	4	5	7	4	4	5	2	3	6
SC (D10/D95)	11	22	54	8	10	14	5	10	41
Fines (sub44µm)	0.3	4.7	12.7	0.1	0.6	1.1	0.0	2.2	11.3
Recommended Sand Control (Flowchart)									
D10 (µm)	SAS	**SAS**	SAS	SAS	**SAS**	SAS	SAS	**SAS**	SAS
D50 (µm)	SAS	**SAS**	SAS	SAS	**SAS**	SAS	SAS	**SAS**	SAS
SC (D10/D95)	OHGP	**OHGP**	OHGP	SAS	**SAS**	OHGP	SAS	**SAS**	OHGP
UC (D40/D90)	Prem./ Mesh	**Prem./ Mesh**	OHGP	Prem./ Mesh	**Prem./ Mesh**	Prem./ Mesh	WWS	**Prem./ Mesh**	OHGP
Fines (sub44µm)	WWS	**Prem./ Mesh**	OHGP	WWS	**WWS**	WWS	WWS	**Prem./ Mesh**	OHGP

Sand 2 Formation	Reservoir 2								
	Sand 2C			Shale 2B			Sand 2A		
	Min	Mean	Max	Min	Mean	Max	Min	Mean	Max
D10 (µm)	237	655	1612	401	749	1375	415	708	952
D50 (µm)	124	248	454	179	370	749	209	301	433
UC (D40/D90)	2	3	6	3	4	6	3	3	5
SC (D10/D95)	4	12	47	10	14	16	6	10	16
Fines (sub44µm)	0.1	3.5	10.9	1.3	4.0	6.2	0.1	1.7	3.7
Recommended Sand Control (Flowchart)									
D10 (µm)	SAS	**SAS**	SAS	SAS	**SAS**	SAS	SAS	**SAS**	SAS
D50 (µm)	SAS	**SAS**	SAS	SAS	**SAS**	SAS	SAS	**SAS**	SAS
SC (D10/D95)	SAS	**OHGP**	OHGP	SAS	**OHGP**	OHGP	SAS	**SAS**	OHGP
UC (D40/D90)	WWS	**Prem./ Mesh**	OHGP	Prem./ Mesh	**Prem./ Mesh**	OHGP	Prem./ Mesh	**Prem./ Mesh**	Prem./ Mesh
Fines (sub44µm)	WWS	**Prem./ Mesh**	OHGP	WWS	**Prem./ Mesh**	OHGP	WWS	**WWS**	Prem./ Mesh

Sand 2 Formation	Reservoir 2					
	Sand 2A					
	Min	Mean	Max	Min	Mean	Max
D10 (µm)	351	490	643	447	682	979
D40 (µm)	205	254	311	240	369	501
D50 (µm)	174	214	254	211	311	408
D90 (µm)	73	88	98	64	102	133
D95 (µm)	54	66	73	35	68	94
UC (D40/D90)	3	3	3	3	4	6
SC (D10/D95)	7	7	9	7	12	27
Fines (sub44µm)	1.2	1.8	2.9	0.8	2.9	5.9
Recommended Sand Control (Flowchart)						
D10 (µm)	SAS	**SAS**	SAS	SAS	**SAS**	SAS
D50 (µm)	SAS	**SAS**	SAS	SAS	**SAS**	SAS
SC (D10/D95)	SAS	**SAS**	SAS	SAS	**OHGP**	OHGP
UC (D40/D90)	Prem./ Mesh	**Prem./ Mesh**	Prem./ Mesh	Prem./ Mesh	**Prem./ Mesh**	OHGP
Fines (sub44µm)	WWS	**WWS**	Prem./ Mesh	WWS	**Prem./ Mesh**	OHGP

APPENDIX H: FORMATION CONDITION AND SHALE

Table H-1: Shale thickness determination of Sand 1 water injectors based on nearby appraisal logs

I1b	Shale Thickness (ft MD)		
Vsh cut-off = 0.5	Min	Average	Max
C	0.3	3.1	18.4
Cst1	3.5		
Cst2	1.0	3.6	13.5
Cst3	0.4	4.6	13.9
	0.3	6.2	18.4

I1/I2 & I1c	Shale Thickness (ft MD)		
Vsh cut-off = 0.5	Min	Average	Max
C	0.3	3.1	18.4
Cst3	0.4	4.6	13.9
D	0.3	9.6	24.6
Dst1	0.8	3.6	8.0
	0.3	7.3	24.6

I1b	Shale Thickness (ft MD)		
Vsh cut-off = 0.5	Min	Average	Max
Est1	0.5	1.5	2.5
	0.5	1.5	2.5

Vsh=0.4	Min	Average	Max
Shale Thick. (ft)	**0.3**	**6**	**25**

Table H-2: Shale thickness determination of Sand 2 water injectors based on nearby appraisal logs

I1b	Shale Thickness (ft MD)		
Vsh cut-off = 0.4	Min	Average	Max
C	0.4	3.6	
Cst1	4.5		
Cst2	1.0	4.6	23.0
Cst3	0.4	7.2	18.6
	0.4	7.0	23.0

I1/I2 & I1c	Shale Thickness (ft MD)		
Vsh cut-off = 0.4	Min	Average	Max
C	0.4	3.6	
Cst3	0.4	7.2	18.6
D	0.3	9.2	25.0
Dst1	0.5	3.2	8.5
	0.3	7.0	25.0

I1a	Shale Thickness (ft MD)		
Vsh cut-off = 0.4	Min	Average	Max
Est1	0.5	1.8	3.5
	0.5	1.9	3.5

Vsh=0.4	Min	Average	Max
Shale Thick. (ft)	**0.3**	**6**	**25**

Table H-3: Minimum, average and maximum of intra-shale layer in Shale 2B (coloured)

	Thickness (ft MD)									
	Appraisal Wells					Proposed Injectors		Min.	Avg.	Max.
Units	A	Ast1	B	Bst1	F	I2b	I2a			
Sand 2C	135	201	116	136	8	87	104	8	112	201
Shale 2B	7	8	5	8	10	36	2	**2**	**11**	**36**
Sand 2A	84	177	125	135	84	161	48	48	116	177

Table H-4: R2 values of Sand 1 and Sand 2

Sand 1	C	Cst1	Cst3	D	Dst1	Est1	**Avg.**
R^2	0.80	0.91	0.64	0.74	0.83	0.78	**0.78**

Sand 2	A	Ast1	B	C	D	Dst1	**Avg.**
R^2	0.82	0.73	0.88	0.92	0.82	0.79	**0.83**

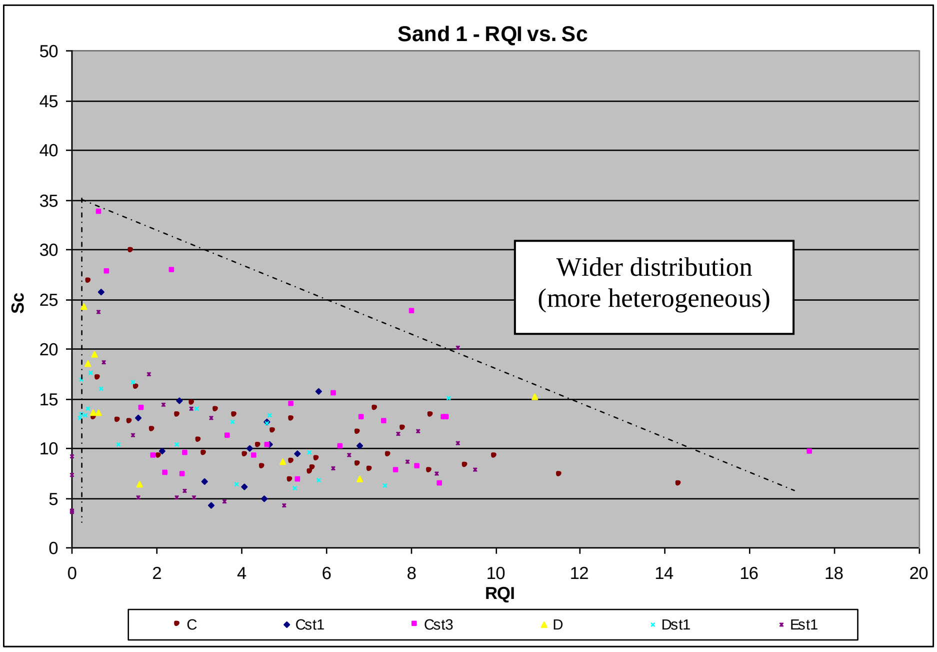

Figure H-1: Rock Quality Index (RQI) vs. Sorting (Sc) of Sand 1

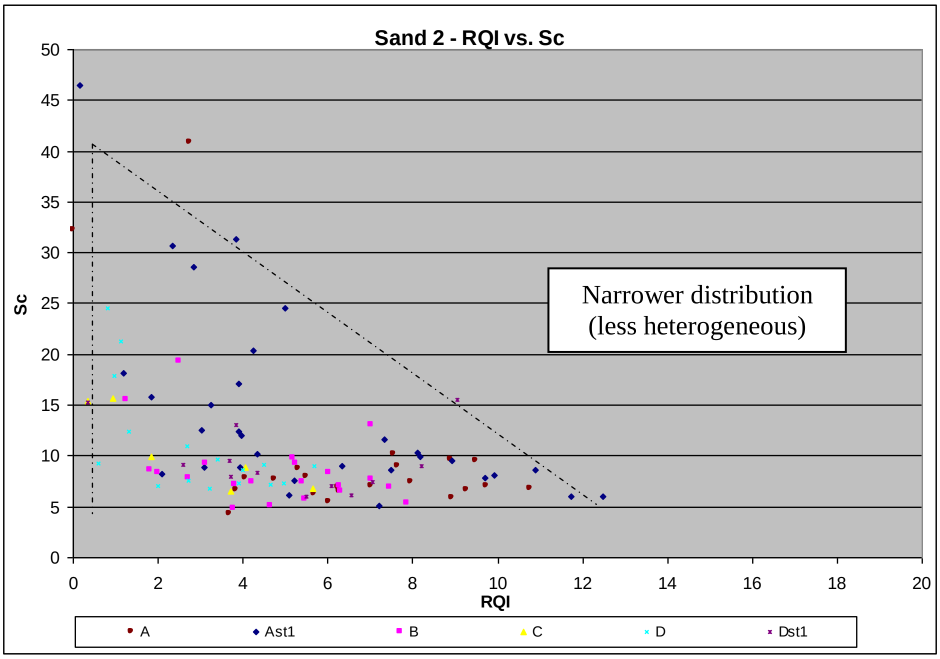

Figure H-2: Rock Quality Index (RQI) vs. Sorting (Sc) of Sand 2

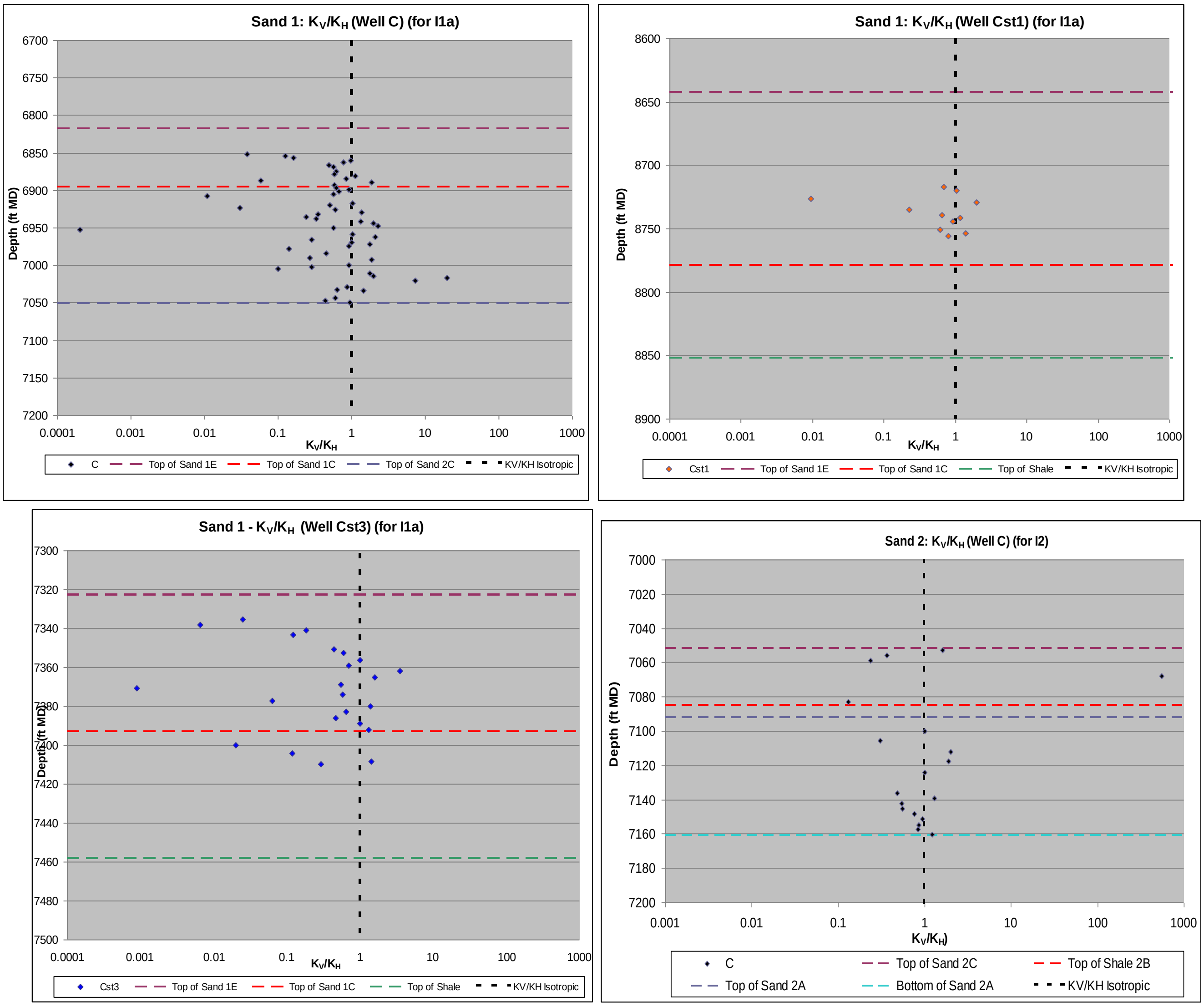

Figure H-3: K_V/K_H for I1a injector; and for I2 injector (bottom right).

APPENDIX I: INJECTION SPLIT RATIO AND ANNULAR FLOW

Table I-1: Ratio of *kh* per unit in Sand 1 for three WIs

Zone	Units	**Ratio of *kh* per unit**	Proposed WI	Design Rate (STWB/d)
Upper Sand 1	Sand 1E	**0.51**	I1a, I1b, I1c	20476
	Sand 1D			
Lower Sand 1	Sand 1C	**0.49**		19524
	Sand 1B			
	Sand 1A			

Table I-2: Ratio of *kh* per unit in a Sand 2 WI (I2a)

Zone	Units	**Ratio of *kh* per unit**	Proposed WI	Design Rate (STWB/d)
Upper Sand 2	Sand 2C	**111**	I2a	35436
Intra-Shale	Shale 2B	**11**		-
Lower Sand 2	Sand 2A	**75**		14564

Table I-3: Ratio of *kh* per unit in a Sand 2 WI (I2b)

Zone	Units	**Ratio of *kh* per unit**	Proposed WI	Design Rate (STWB/d)
Upper Sand 2	Sand 2C	**0.61**	I2b	30318
Intra-Shale	Shale 2B	-		-
Lower Sand 2	Sand 2A	**0.39**		19682

Table I-4: Ratio of *kh* per unit in Sands 1 and 2 for a commingling WI (I1/ I2)

Zone	Units	**Ratio of *kh* per unit**	Proposed WI	Design Rate (STWB/d)
Upper Sand 1	Sand 1E	**0.16**	I1	7904
	Sand 1D			
Lower Sand 1	Sand 1C	**0.15**		7537
	Sand 1B			
	Sand 1A			
Upper Sand 2	Sand 2C	**0.49**	I2	24492
Intra-Shale	Shale 2B	-		-
Lower Sand 2	Sand 2A	**0.20**		10066

Table I-5: A summary of ICV aperture required to achieve the injection split ratios for water injectors in Sand 1

I1b				NETool™ (±5%)				
				SAS only		SAS + ICV		ICV Configuration
Zone	Units	*kh* ratio per unit	Design Rate (stbw/d)	Split Ratio	Injection Rate	**Split Ratio**	**Injection Rate**	**ICV**
Upper Sand 1	Sand 1E Sand 1D	0.51	20476	0.35	14000	**0.52**	**20800**	**5% opening**
Lower Sand 1	Sand 1C Sand 1B Sand 1A	0.49	19524	0.65	26000	**0.48**	**19200**	**5% opening**
I1c				**NETool™ (±5%)**				
				SAS only		**SAS + ICV**		**ICV Configuration**
Zone	Units	*kh* ratio per unit	Design Rate (stbw/d)	Split Ratio	Injection Rate	**Split Ratio**	**Injection Rate**	**ICV**
Upper Sand 1	Sand 1E Sand 1D	0.51	20476	0.35	14000	**0.52**	**20880**	**70% opening**
Lower Sand 1	Sand 1C Sand 1B Sand 1A	0.49	19524	0.65	26000	**0.48**	**19120**	**15% opening**
I1a				**NETool™ (±5%)**				
				SAS only		**SAS + ICV**		**ICV Configuration**
Zone	Units	*kh* ratio per unit	Design Rate (stbw/d)	Split Ratio	Injection Rate	**Split Ratio**	**Injection Rate**	**ICV**
Upper Sand 1	Sand 1E Sand 1D	0.51	20476	0.52	20680	**0.83**	**33200**	**9% opening**
Lower Sand 1	Sand 1C Sand 1B Sand 1A	0.49	19524	0.48	19320	**0.17**	**6800**	**80% opening**

Table I-6: ICV aperture in the commingling I1/ I2 for Sands 1 and 2

PI/BI-M-BK				**NETool^{TM} (±5%)**				
				SAS only		**SAS + ICV**		**ICV Configuration**
Zone	Units	*kh* ratio per unit	Design Rate (stbw/d)	Split Ratio	Injection Rate	**Split Ratio**	**Injection Rate**	**ICV**
Upper Sand 1	Sand 1E Sand 1D	0.16	7904	0.07	3500	**0.15**	**7719**	**6% opening**
Lower Sand 1	Sand 1C Sand 1B Sand 1A	0.15	7537	0.13	6500	**0.15**	**7572**	**100% opening**
Upper Sand 2	Sand 2C	0.49	24492	0.41	20500	**0.50**	**24959**	**100% opening**
Intra-Shale	Shale 2B	-	-	-	-	**-**	**-**	
Lower Sand 2	Sand 2A	0.20	10066	0.39	19500	**0.20**	**9750**	**7% opening**

Table I-7: A summary of ICV aperture required to achieve the injection split ratios for water injectors in Sand 2.

I2b				NETool™ (±5%)				
				SAS only		SAS + ICV		ICV Configuration
Zone	Units	*kh* ratio per unit	Design Rate (stbw/d)	Split Ratio	Injection Rate	**Split Ratio**	**Injection Rate**	**ICV**
Upper Sand 2	Sand 2C	0.61	30318	0.69	34500	**0.61**	**30400**	**30% opening**
Intra-Shale	Shale 2B	-	-	-	-	**-**	**-**	
Lower Sand 2	Sand 2A	0.39	19682	0.31	15500	**0.39**	**19600**	**60% opening**

I2a				NETool™ (±5%)				
				SAS only		SAS + ICV		ICV Configuration
Zone	Units	*kh* ratio per unit	Design Rate (stbw/d)	Split Ratio	Injection Rate	**Split Ratio**	**Injection Rate**	**ICV**
Upper Sand 2	Sand 2C	0.71	35436	0.96	48000	**0.73**	**36550**	**15% opening**
Intra-Shale	Shale 2B	-	-	-	-	**-**	**-**	
Lower Sand 2	Sand 2A	0.29	14564	0.04	2000	**0.27**	**13450**	**80% opening**

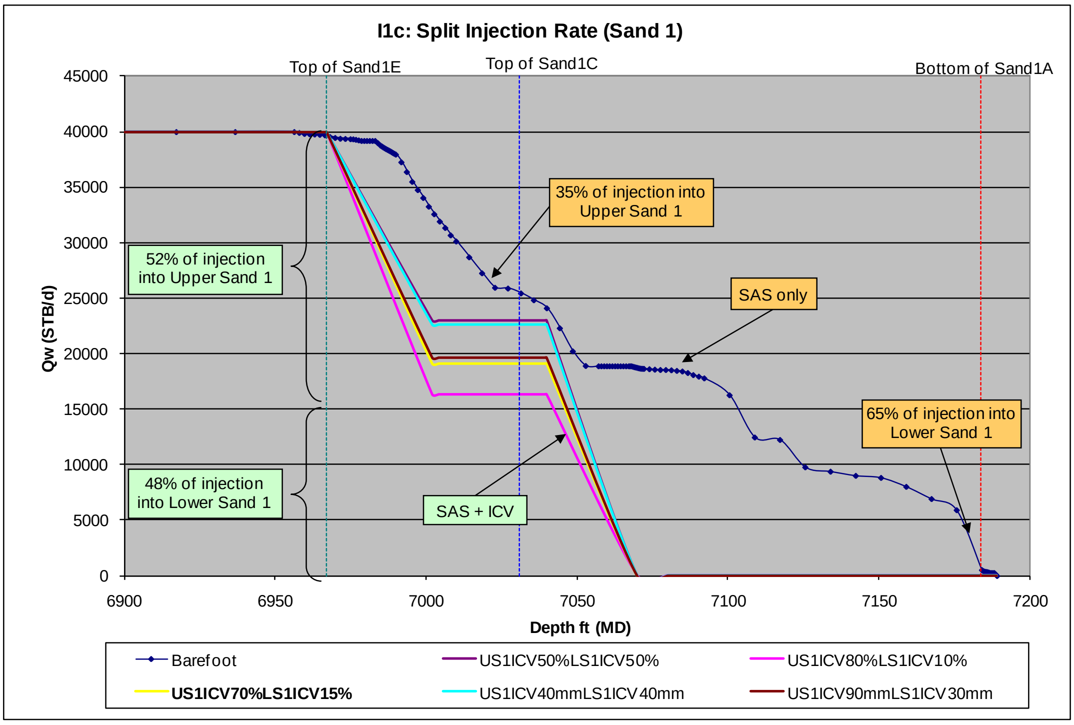

Figure I-1: I1c injection profile comparison for SAS only and SAS with ICV.

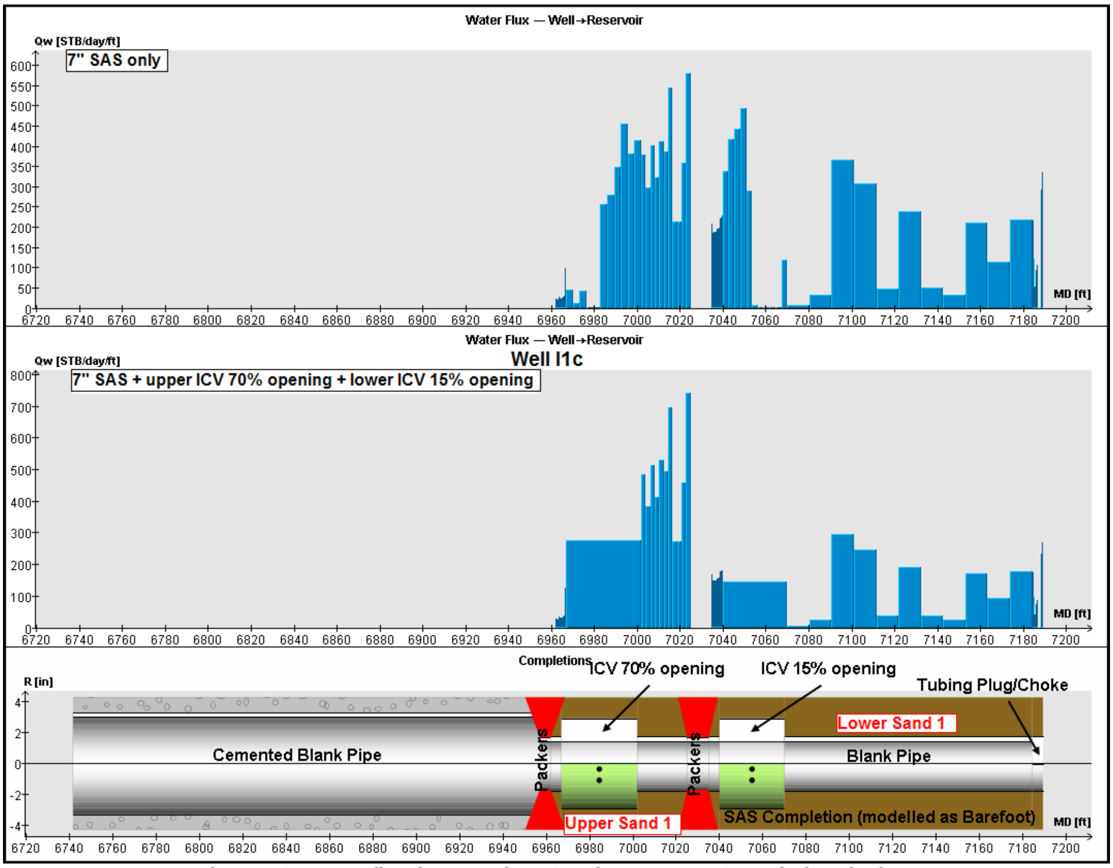

Figure I-2: Water flux from I1c into Sand 1. Bottom: Completion design.

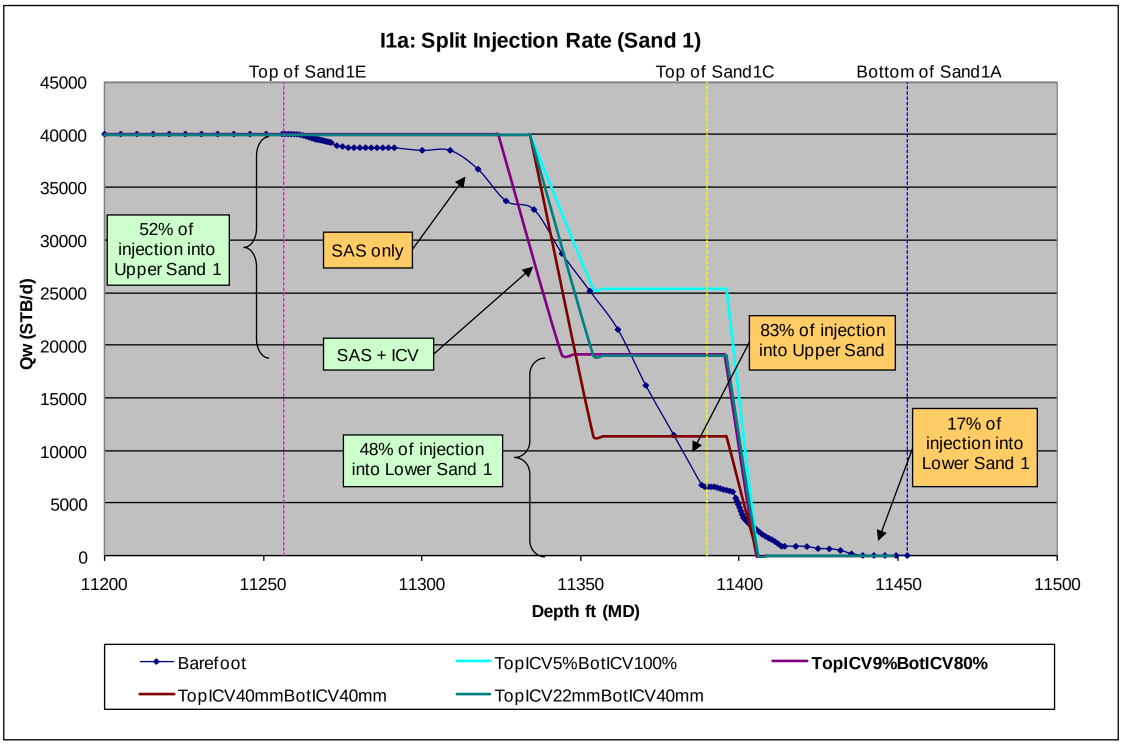

Figure I-3: I1a injection profile comparison for SAS only and SAS with ICV.

Figure I-4: Water flux from I1a into Sand 1. Bottom: Completion design.

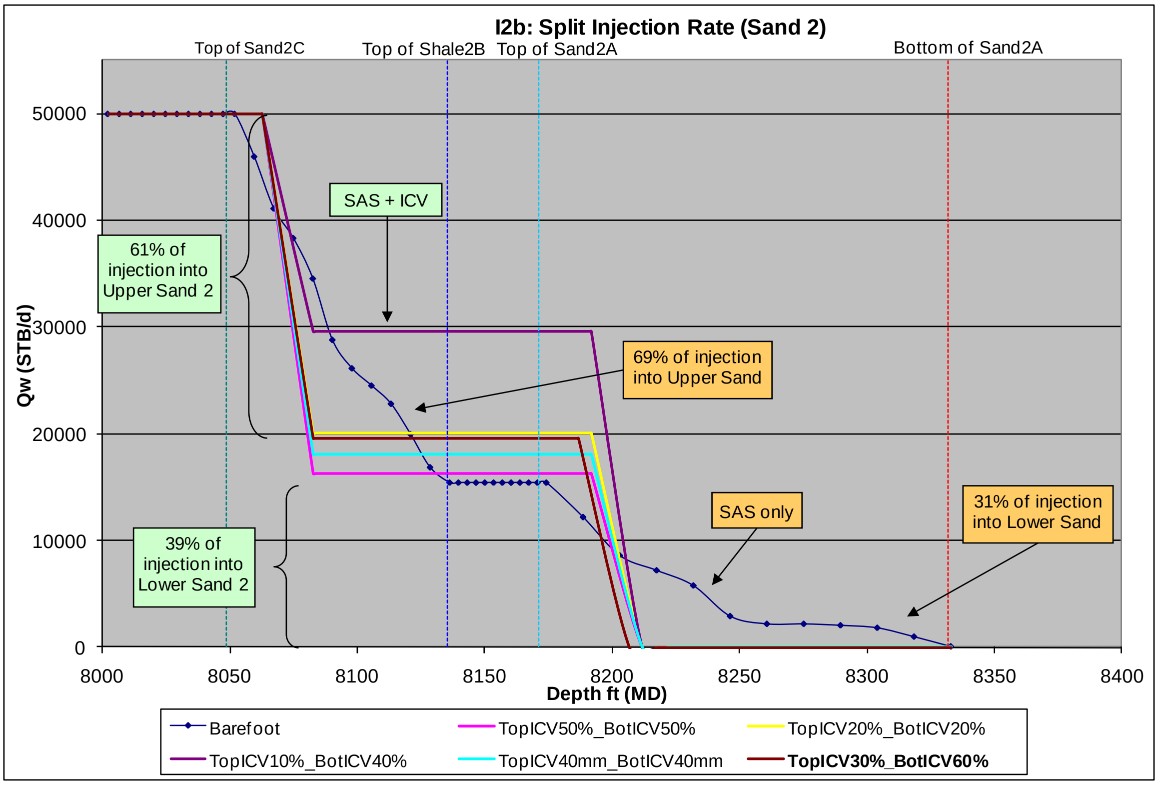

Figure I-5: I2b injection profile comparison for SAS only and SAS with ICV.

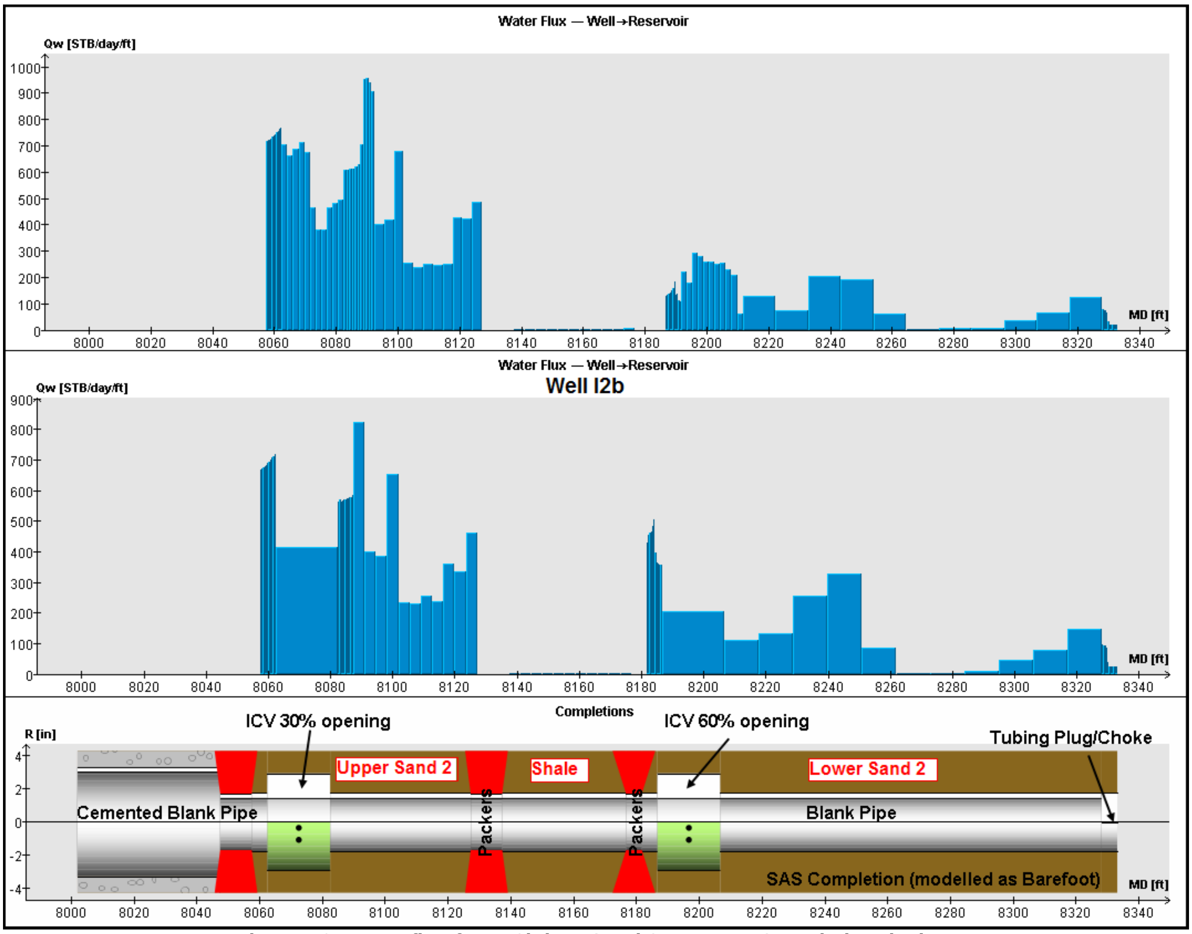

Figure I-6: Water flux from I2b into Sand 2. Bottom: Completion design.

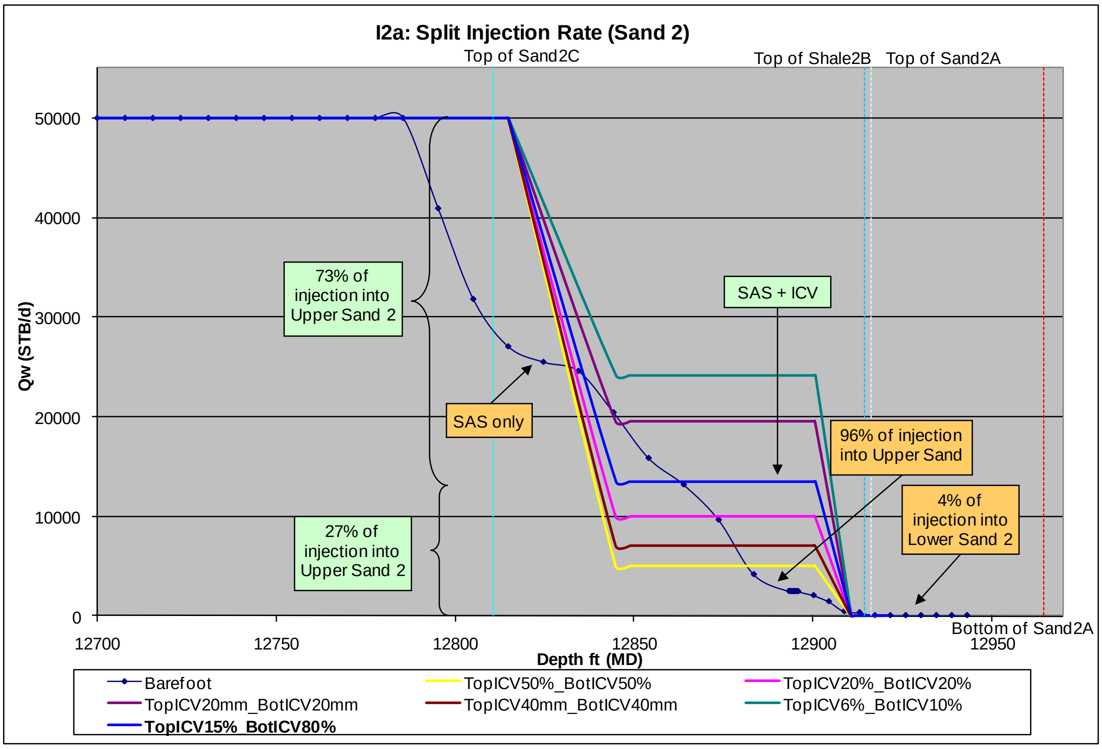

Figure I-7: I2a injection profile comparison for SAS only and SAS with ICV.

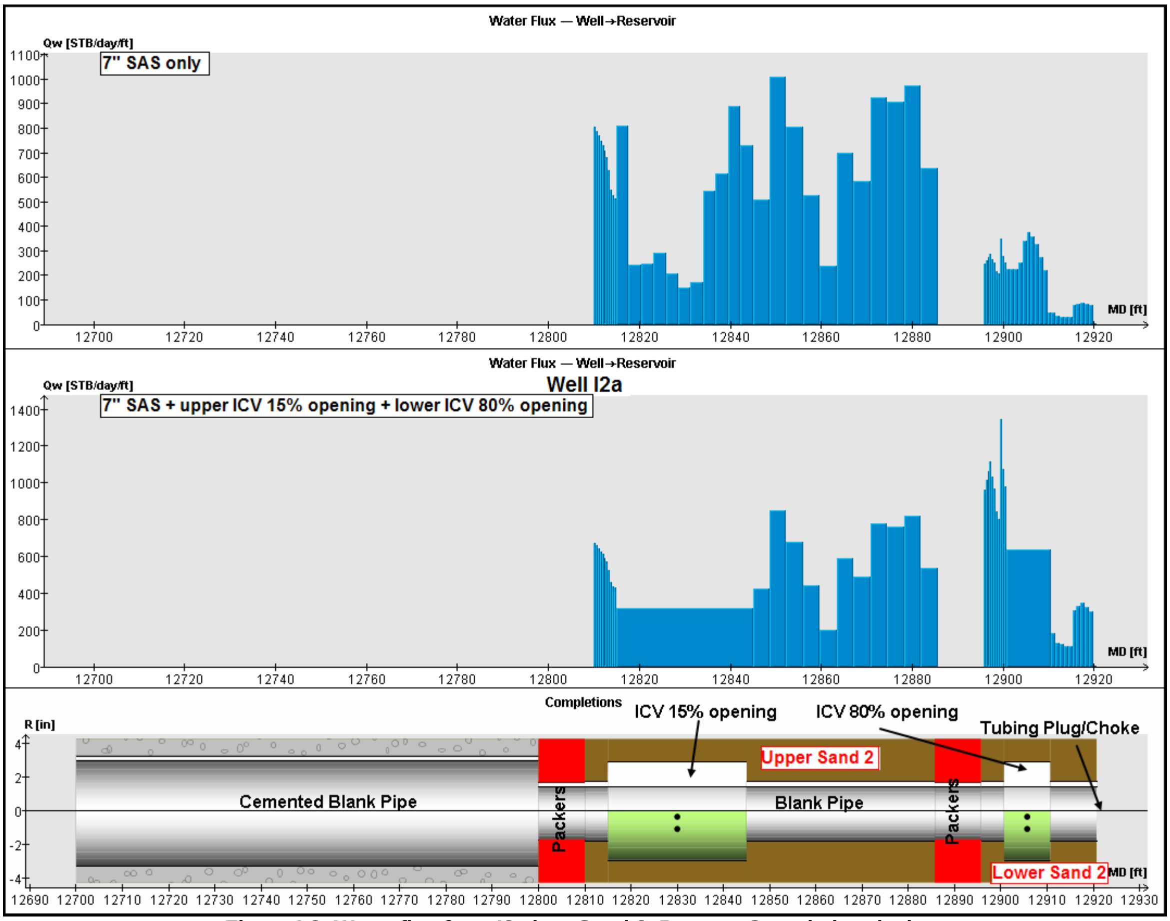

Figure I-8: Water flux from I2a into Sand 2. Bottom: Completion design.

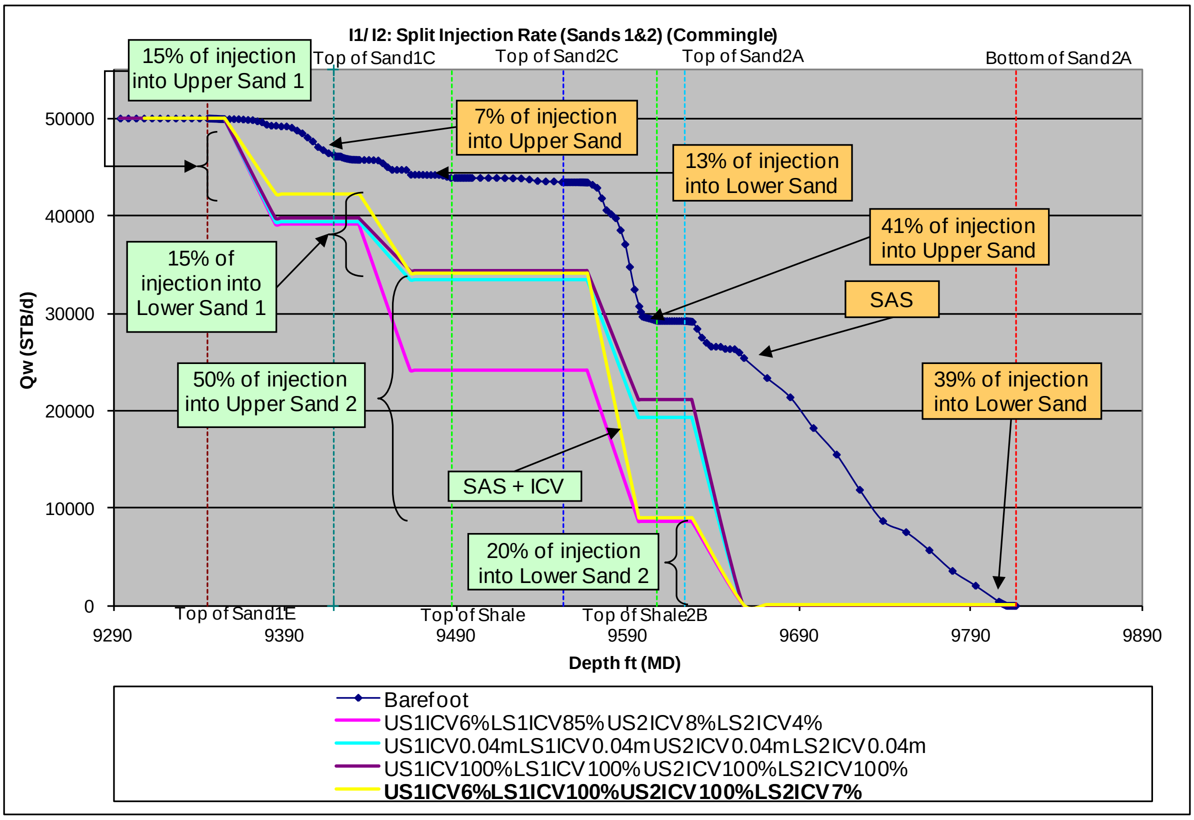

Figure I-9: I1/ I2 injection profile comparison for SAS only and SAS with ICV.

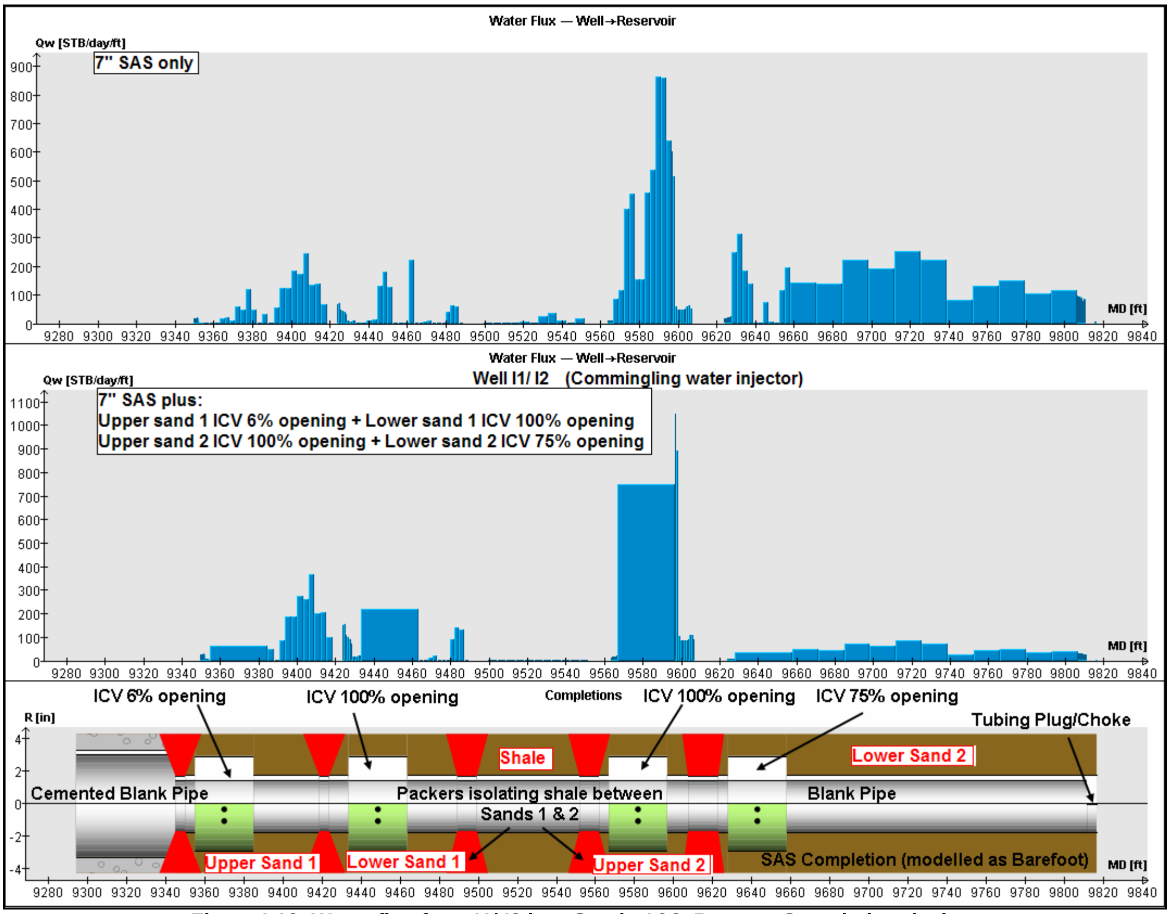

Figure I-10: Water flux from I1/ I2 into Sands 1&2. Bottom: Completion design.

Table I-8: Completion parameters of the six water injectors with optimised ICVs aperture.

Well Parameters	Sand 1			Sand 2		Sand 1	Sand 2
Water Injector	**I1a**	**I1b**	**I1c**	**I2a**	**I2b**	**I1/ I2**	
Reservoir Drainage MD (ft)	197	217	222	154	283	143	264
Wellbore Diameter	8.5"OD (6"ID)	8.5"OD (6"ID)	8.5"OD (6"ID)	8.5"OD (6"ID)	8.5"OD (6"ID)	8.5"OD (6"ID)	8.5"OD (6"ID)
Screen Diameter	7.6"OD (6.184"ID)	7.6"OD (6.184"ID)	7.6"OD (6.184"ID)	7.6"OD (6.184"ID)	7.6"OD (6.184"ID)	7.6"OD (6.184"ID)	
Blank Pipe	3.5"OD (2.875"ID)	3.5"OD (2.875"ID)	3.5"OD (2.875"ID)	3.5"OD (2.875"ID)	3.5"OD (2.875"ID)	3.5"OD (2.875"ID)	
Inflow Control Valve (ICV)	5.8"OD (2.875"ID)	5.8"OD (2.875"ID)	5.8"OD (2.875"ID)	5.8"OD (2.875"ID)	5.8"OD (2.875"ID)	5.8"OD (2.875"ID)	
Upper Zone ICV	9% opening	5% opening	70% opening	15% opening	30% opening	6% opening	100% opening
Lower Zone ICV	80% opening	5% opening	15% opening	80% opening	60% opening	100% opening	7% opening

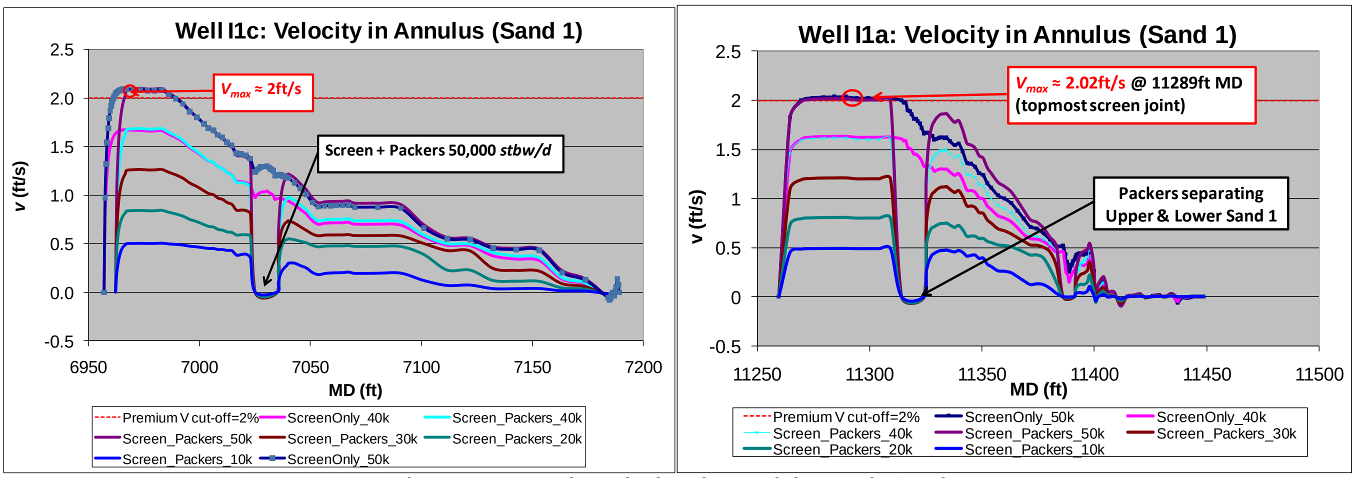

Figure I-11: Annular velocity of water injectors in Sand 1.

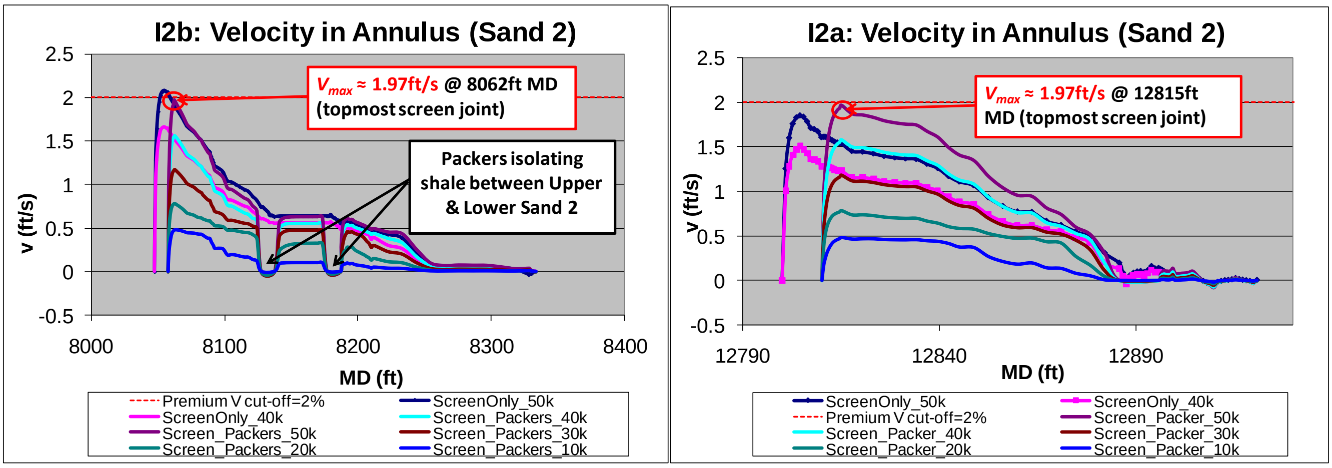

Figure I-12: Annular velocity of water injectors in Sand 2.

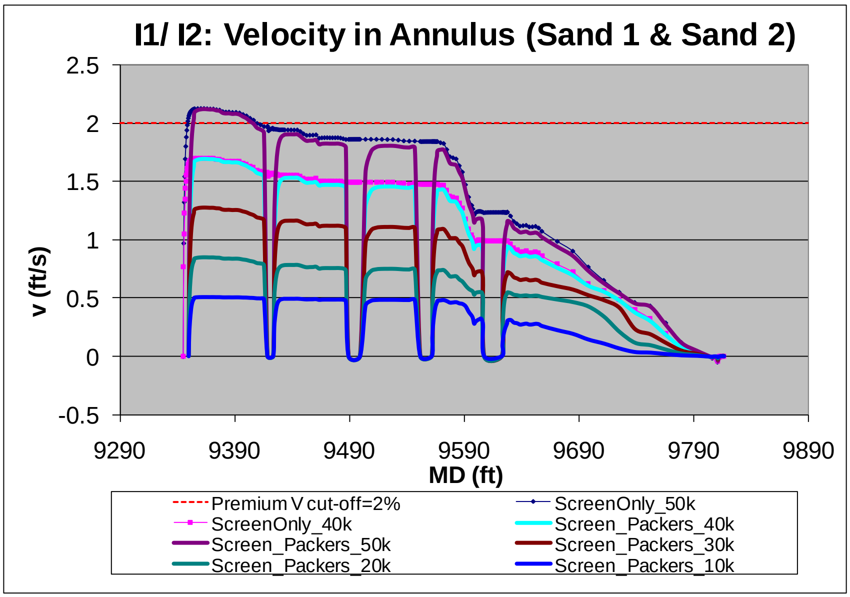

Figure I-13: Annular velocity of water injectors in Sands 1 & 2 (commingle).

Table I-9: Sensitivity analysis of annular fluid velocities from 10-50kstbw/d for water injections in both reservoirs.

Sand 1		Screen Annular Velocity (ft/s) (NETool™)									
Water Injectors		(2) I1a					(3) I1c				
Injection Rates (stbw/d)		10K	20K	30K	40K	50K	10K	20K	30K	40K	50K
Sand 1	Upper Sand 1	0.5	0.8	1.2	1.6	2.0	0.5	0.8	1.3	1.7	2.1
	Lower Sand 1	0.1	0.2	0.4	0.5	0.5	0.3	0.5	0.7	1.0	1.2
Sand 2	Upper Sand 2										
	Lower Sand 2										

Sand 2		Screen Annular Velocity (ft/s) (NETool™)									
Water Injectors		(4) I2a					(5) I2b				
Injection Rates (stbw /D)		10K	20K	30K	40K	50K	10K	20K	30K	40K	50K
Sand 1	Upper Sand 1										
	Lower Sand 1										
Sand 2	Upper Sand 2	0.5	0.8	1.2	1.6	2.0	0.5	0.8	1.2	1.6	2.0
	Lower Sand 2	0.0	0.0	0.0	0.0	0.0	0.1	0.3	0.5	0.5	0.6

Sand 1 & Sand 2		Screen Annular Velocity (ft/s) (NETool™)				
Water Injectors		(6) I1/ I2				
Injection Rates (stbw /D)		10K	20K	30K	40K	50K
Sand 1	Upper Sand 1	0.5	0.8	1.3	1.7	2.1
	Lower Sand 1	0.5	0.8	1.2	1.5	1.9
Sand 2	Upper Sand 2	0.5	0.7	1.1	1.4	1.8
	Lower Sand 2	0.3	0.5	0.7	0.9	1.2

< 1.5ft/s	Low Risk
1.5 - 2ft/s	Moderate Risk
>2ft/s	High Risk

APPENDIX J: iPoint 2011 (Perigon Solutions)

The iPoint software is a visual and an integrated tool for subsurface wellbore data. The tool enables the user to have an integrated visual of core and wireline log interpretation in a single screen. Below is a visual example of various geological and reservoir description of one of the appraisal wells used in the case study.

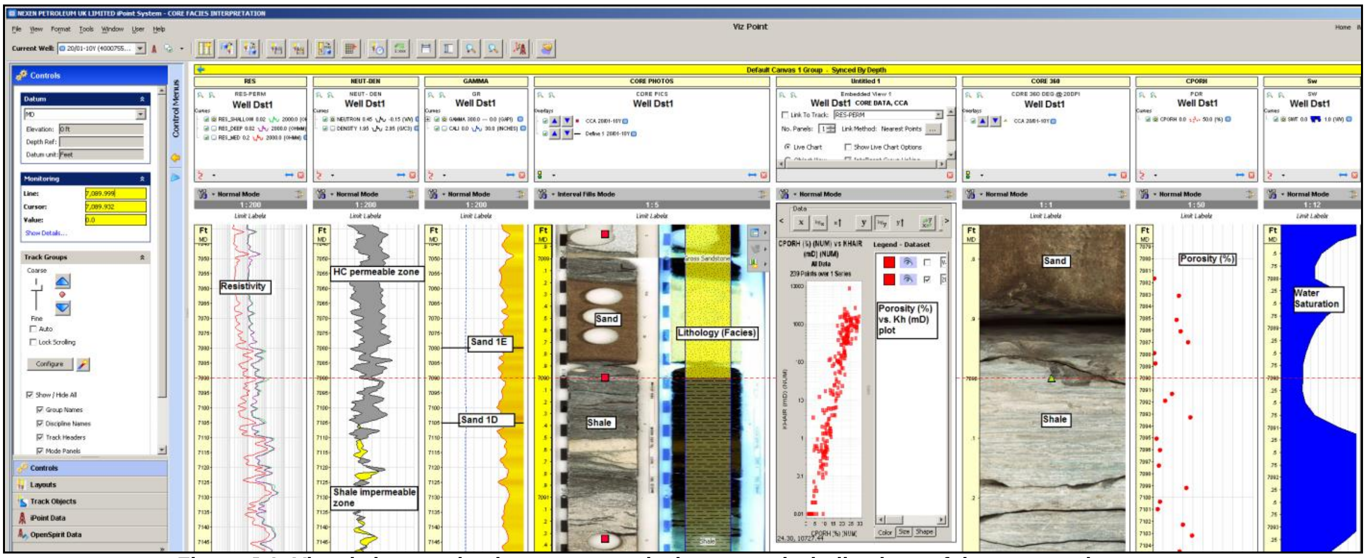

Figure J-1: Visual view used to interpret appraisal cores and wireline logs of the case study.

APPENDIX K: NETool™ 5000.0.0.0 (Landmark)

The use of NETool™ is to build a numerical model based on the reservoir, completion and fluid input. The software is populated with well information, reservoir and completion data prior to performing the stimulations. The reservoir model (using the standard black-oil Eclipse E100 stimulator) was uploaded into NETool™. The co-ordinates and survey data of the water injectors was imported from Landmark's COMPASS™.

Figure K-1 below shows the data requirements for NETool™ stimulation and Figure K-2 is prior to stimulation:

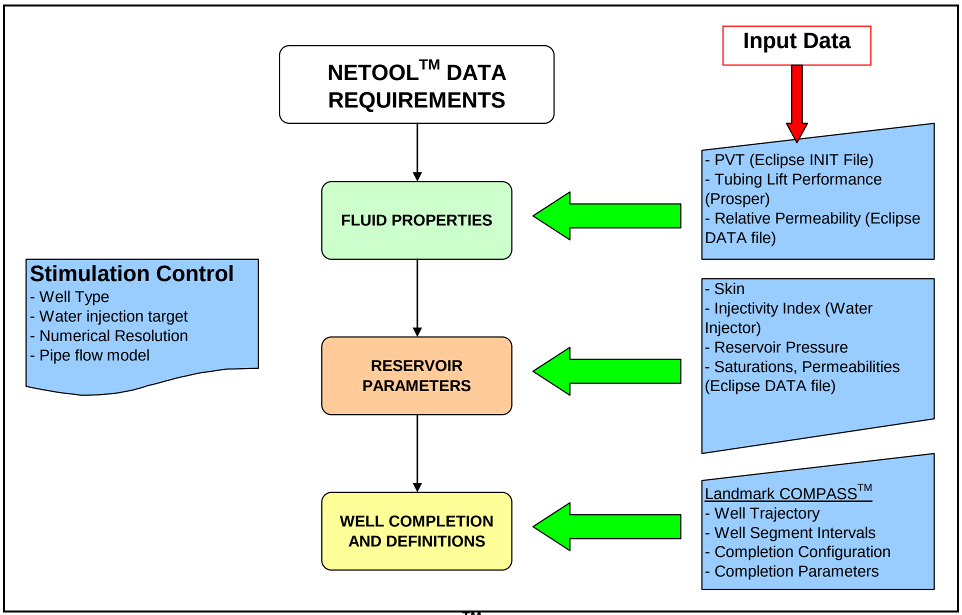

Figure K-1: NETool™ workflow data input.

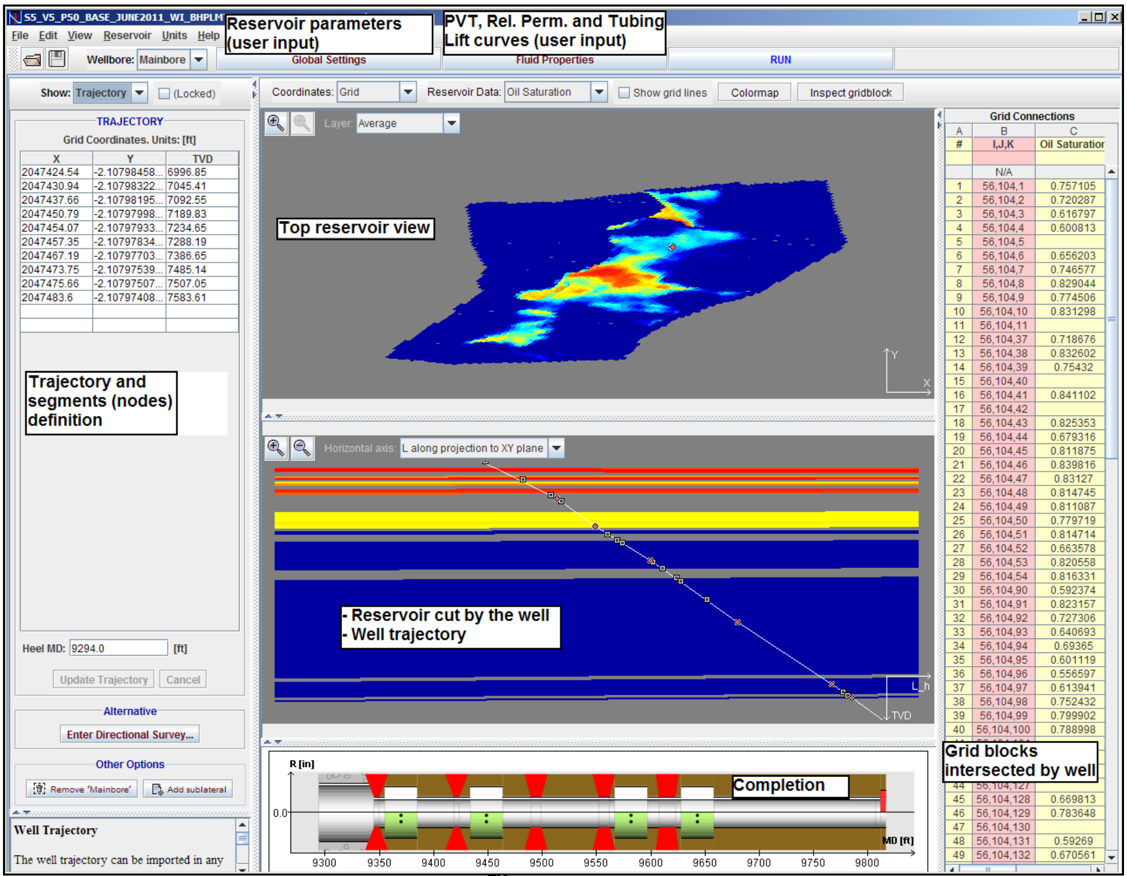

Figure K-2: NETool™ main menu prior to stimulation.