An Integrated Approach to Optimizing Completions and Protecting Parent Wells in the Montney Formation, N.E.B.C.

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Abstract

The Montney formation in British Columbia and Alberta has gained prominence in recent years due to the exploration and production boom which has yielded more than 3.5 billion bcf/d in production output and in excess of 440 TCF of reserves. It is one of the largest unconventional plays in N. America, covering 130,000km\textsuperscript{2} with more than 5600 wells drilled to date. The figure below, illustrates the Montney reservoir trend and Canbriam’s position in Altares in N.E. British Columbia. Canbriam is a private company currently with 40,000Boe/d producing capacity and a deep inventory of over-pressured, liquids-rich locations with stable, low-decline. The map also highlights some of Canbriam’s seismometer and accelerometer arrays in North Altares. The key to optimizing completions and protecting ‘parent’ wells is a thorough understanding of the subsurface. This paper describes multidisciplinary integration at Canbriam, which integrates subsurface reservoir characterization, including fault and fracture identification, with real-time pressure monitoring to assist in prediction of inter-well communication during completions. This also allows the production engineers to identify offsetting ‘parent’ wells which will require mitigation during the ‘child well’ completions. Operationally, Canbriam has RTC or ‘request to complete’ meetings which include full integration of subsurface and operations teams. Decisions in these meetings are relayed to the field to ensure any potential risks such as; inter-well communication, possible casing deformation and Induced Seismicity are well understood.
**Introduction**

Canbriam’s integration philosophy starts with a full ‘shared earth’ model of the subsurface in the Altares field. The first step is to build a structural model which is based upon the 3D seismic data interpretation. This model incorporates the major faults and structural features as well as the main geological markers over the area covered by 3D seismic. On this framework, a geocellular grid is built which honors the geology as closely as possible but limiting the number of cells to allow efficient future reservoir modelling and simulation.

This up-scaled geocellular model is subsequently populated with petrophysical and mechanical properties using inversion of the AVO compliant pre-stack data. Volumes produced include; porosity, saturation, Young’s modulus and Poisson’s ratio. Figure 2 below illustrates the concept.

![Figure 2: Structural and Geocellular models used in Altares Shared Earth model.](image)

The geocellular model provides the building blocks with which to populate the pre-stack inversion properties and later, a permeability property for the ‘dynamic model’ used to simulate individual hydraulic frack completions. This permeability, discussed in a later section, has been determined using DFIT analysis correlated to in-situ porosity. The quality of the pre-stack inversion products is dependent, apart from seismic acquisition considerations, upon the quality of seismic data conditioning workflows which aim to optimize the 3D seismic data for the AVO inversion.

![Figure 3: Workflow to create Pre-Stack Inversion Rock Properties.](image)

The final seismic gathers were used to generate a set of partial angle stacks which were further conditioned and matched for spectral balancing and time misalignments between the near, mid and far stacks. The final step was to
balance the amplitudes with offset based on AVO models at key well locations. Figure 3 demonstrates part of the work flow using the Altares 3D seismic data.

Once pre-stack inversion products have been calculated, property volumes are created which are used to optimize well planning. One such volume is the core calibrated density porosity, where the porosity logs and the inversion derived rock properties are trained together at the well locations in order to establish a geostatistical relationship (using multi attribute linear regression and neural networks) between them. This relationship is then propagated at each trace location throughout the 3D volume. Blind testing, which omits vertical wells from the prediction indicates the resulting porosity volume prediction is robust. Figure 4 illustrates both Upper and Lower Montney target horizons in Altares, with corresponding drilling locations in 5 zones or benches within the 320m vertical thickness.

Figure 4: Development drilling planning using a porosity volume derived from logs and 3D seismic data.

Hot colors indicate high porosity values. The resulting OGIP calculated for this volume is fundamental in determining the number of wells in a zone with a ‘reasonable’ recovery factor. This in turn, influences well-spacing decisions in the development area.

An important next step in understanding the subsurface is to map faults and fractures in a discrete fracture network.

Figure 5: Discrete Fracture Network (top) and DFN shown in the simulator-ready static earth model.
or DFN. The DFN forms a key component in the ‘static earth model’ which is used in both completions planning and subsequent frack treatment and reservoir simulation work. Figure 5 shows the DFN for the Altares field. It is constructed using several 3D seismic edge detection methods including coherency and ant tracking as inputs and populated using both stochastic and deterministic methods. Understanding the natural fracture network in the field permits the completions engineer to optimize the completion by changing stage or sliding sleeve spacing to avoid certain fracture types. Completion intensity can also be reduced should the ‘real-time monitored’ induced seismicity events warrant it. (Nieto et al, 2018).

Knowledge of the direction and stress state of the fracture network plays a primary role in deciding which parent wells to protect during child well completions and when to expect frack hits on the Parent wells. (Janega, 2018). The static earth model shown is then used to initialize stage by stage hydraulic fracture modeling. The modeling requires up-scaled, gridded, permeability as one of the many inputs. This has been developed at Canbriam by using DFIT data acquired at the toe of each horizontal well. The in-situ permeability is then used directly as an input to the model, calibrated to 3D seismically derived rock properties. In addition, the DFIT analysis yields minimum horizontal stress magnitude from which a sigma3 volume is created from 3D seismic properties and then used in the hydraulic fracture simulation model. Interestingly, both permeability and stress regimes can be seen to vary with proximity to certain fault types, which has also been observed on microseismic data when fracking in proximity to these faults. Completions performed next to thrust faults tend to ‘frack’ away from the fault due to the enhanced level of stress close to the fault, and give asymmetrical frack geometry. An example of this is shown in Figure 6.

![Figure 6: Asymmetrical Microseismic data in proximity to faults](image)

The completions can be modeled post job, where treatment pressure and rate history are matched with sleeve by sleeve frack job parameters. This allows the prediction in future frack jobs of the direction and magnitude of the hydraulic fractures created in relation to the discontinuities in the ‘static earth model’.
The example shown in figure 7 uses a dual permeability and dual porosity model for natural fractures and matrix to predict direction and continuity of the hydraulically created fractures. The in-situ matrix permeability is generated from DFIT analysis on every horizontal well that reached horizontal radial flow, which is then matched to porosity extracted from 3D seismic inversion over the same interval as the DFIT. The Kinetix frack simulation model defined the proppant size, tonnage, fluid viscosity, fluid volume and rate, in order to predict the extent of the fractures created and how far pressure, water and proppant of different sizes propagates into the formation along the newly created fractures. When the hydraulic fractures hit or intersect a natural fracture, they can:

- Be truncated or stopped
- Continue through the natural fracture with water only
- Continue through the natural fracture with proppant

Figure 8: Stage 2 hydraulic fracture pump schedule (simulated and placed)
Figure 8 is the simulation treatment chart for stage 2 of the well shown in figure 7. This treatment chart shows the match between the simulated and pumped proppant (surface and bottom hole), as well as treatment pressures. History matching is required to ensure the predicted fracture geometry is accurate.

In all cases, the hydraulic fracture modelling has assisted in understanding where offsetting wells will be hit by fluid and proppant. The communication prediction case shown in figure 7 was corroborated by pressure monitoring in the offset well, where the hydraulic frack hit the offset well at the exact sleeve that was highlighted pre-job by the subsurface team.

**Completions Optimization – Natural Fracture Identification**

Optimization of completions is the main reason that this reservoir characterization and simulation work has been performed. The reasoning behind this is that hydraulic fracturing into an existing fault or fracture set will not create the complexity in terms of new surface area in the stimulated rock volume. In addition, the likelihood of ‘hitting’ an offset well is higher, causing more well damage than if there was no conduit between the wells. Finally, Induced seismicity and casing deformation can also be mitigated using the full subsurface model. (Nieto et al. 2018)

The natural fracture identification work starts with correct processing of the 3D seismic, maximizing the signal to noise in the data. Integration of open-hole well logs and core data with the 3D seismic and the use of microseismic data are also important. No one fracture indicator method can be used in isolation, but when several co-exist, flags are raised to the completion operations team. A traffic light protocol has been developed at Canbriam to assist with communications to the completions engineer in the field. An additional traffic light protocol exists to mitigate induced seismic events based upon our seismic event monitoring work, which is described by Yenier et al. 2017.

To summarize, the following methods are used collectively to identify regions in the horizontal wells which are possibly fractured and therefore would not lead to optimal stimulation and may increase the risk of inter-well communication. These are discussed prior to every frack job and understood by the whole Canbriam team. Areas that are likely to be a problem are flagged so that the completions team can ‘call’ a stage (or sleeve) early if direct communication with an offset well is seen (real time pressure monitoring on offset wells as described previously in the reservoir characterization section). In some cases where the likelihood of casing crimping and induced seismicity events are high, sleeves may be omitted completely.

Figure 9: Natural Fracture Identification tools (Top) - AvAz, open fracture detection and increased concentration at toe of well (Bottom) - Young’s modulus extraction along well bore more showing brittle zones
Four different fracture detection techniques are described below and illustrated in figures 9 & 10.

- Specialist processing to generate for example, amplitude versus azimuth volumes (AvAz) from the seismic has been useful in identifying open fracture density in the field. Completion rates are usually indicated higher in areas of high AvAz. (high open natural fracture density).
- Identification of tighter, higher Young’s modulus intervals in the horizontal wells which can indicate calcite healed natural fractures. These fractures form planes of weakness during the completion which reduce complexity and can also indicate regions of high mechanical properties contrast which could lead to casing deformation. The resulting data is propagated into the 3D seismic to produce a Young’s modulus volume. The Young’s modulus value can then be extracted along the wellbore to give a ‘pseudo-log’.
- Direct fracture identification from seismic edge detection products. These products have different levels of resolution but can collectively give confidence in the decision whether to complete a sleeve or stage. Coherency volumes together with ‘ant-track’ volumes taken as a slice at the well trajectory level have proven to be very effective.
- Microseismic data are useful to indicate which natural faults and fractures take completions energy. This is pathway is not always correlated to the edge detection products and can indicate where inter well communication could occur when subsequent offset wells are completed. Pressure monitoring in an offset well which shows microseismic events cutting across it usually has an increased pressure response.

Reservoir characterization is critical in predicting when and where inter-well frack communication is likely to occur between parent and child wells. As outlined previously, techniques such as; generating AvAz volumes, identifying higher Young’s modulus intervals, use of seismic edge detection products, and use of micro-seismic data, are all applied to assess the probability and severity of inter-well communication (parent-child well communication). This workflow enables the subsurface and operations teams to proactively manage and mitigate parent well damage.

**Parent/Child Wells; Overview of Concept**

The terms ‘Parent’ and ‘Child’ wells are well-known in unconventional reservoir development. Figure 11 illustrates the concept. The parent well is usually the first well drilled and completed in an area and often exhibits high a EUR. Over time, perhaps years, the well becomes normally depleted by production. The child well shown in figure 10 is drilled and completed and the fracks tend to be asymmetrical (shown by microseismic). The frack is drawn towards
the lower pressure area and hits the parent well hard with pressure and frack water. It can also displace sand from the proppant pack in the Parent well and cause damage, as discussed later in a case study example. Mitigation measures to ensure the parent well returns to the same production as before the child well was completed have been developed.

Parent/Child Wells; a Case Study with no Mitigation

The map outlined in figure 12 below, is a case study on the c-27-H/94-B-8 well which was drilled and completed in 2012, with no offsetting production. This well, the ‘parent’, is shown in black. Ten frack stages were pumped with 4 and 5 perf clusters per stage at 130 ft. perf spacing. The c-27-H/94-B-8 well produced without offsetting wells (unbounded) until 2015, when 4 ‘child’ wells were drilled and completed to the south of the parent well, shown in blue on figure 12. When these four child wells were completed, direct frack communication was seen in the c-27-H/94-B-8 parent well. In 2016, two more child wells were drilled to the north of the c-27-H/94-B-8 parent well, shown in red, again resulting in direct frack communication to the parent well.

Figure 11: Parent and Child well; no mitigation measures taken.

Figure 12: Case study of c-27-H/94-B-8 well (Parent well in black, Child wells in red and blue)
Below, in Figure 13, are the production and casing pressure histories for the unmitigated c-27-H/94-B-8 parent well. The figure shows gas rate in red and casing pressure in green. Production rate from the well, shown in red, exhibits low decline as wells are normally choked back in our highly over-pressured field. The casing pressure also exhibits decline, having produced ~4 BCF over a 3 year period.

Offset frac communication can be seen in July 2015 from the c-17-H/94-B-8 child wells (4) and again in July 2016 from the c-27-H/94-B-8 child wells (2). Offset frac communication is identified by abnormally high and erratic casing pressure responses, as shown by the green curve on the figure. These pressure responses are due to fluid flow into the c-27-H/94-B-8 wellbore during offset frac operations. Upon resuming production of the parent well, (number 3 in the diary on figure 13), clear reductions in casing pressure and gas rate (red curve) were observed.

A systematic approach was taken to confirm that the loss in production was not due to a wellbore restriction or liquid loading. In September 2016 a coiled tubing cleanout was performed on the well and no significant plug debris or sand was recovered. The well was then swabbed and brought back online with no production improvement. In December 2016 the well was placed on gas lift to address potential liquid loading, and no incremental production was observed. In June 2017 a flow and build-up was performed to evaluate the well and quantify the damage.

Validating and Quantifying the Case Study Parent Well Damage

In addition to the flow and build-up, an interference test was performed to confirm that the reduction in inflow was not due to interference between wells or depletion. Figure 14 shows the flow and build-up plot, as well as the interference test. While minor inter-well communication was seen, (red, green and blue curves), it was concluded that interference was not the source of production impairment.
The next step was to perform pressure transient analysis (PTA) using various analytical models with a view to establishing whether the formation showed flow related to a higher permeability proppant pack or low permeability related to formation damage, or skin. Analysis shows that linear horizontal flow was not seen on the derivative plot, which would be expected from a fracked horizontal well. The red line in figure 15 below would be a typical response. The actual data followed more of an unstimulated horizontal well response, shown by the blue line, so the initial model used was an unstimulated horizontal well.

The results of the pressure transient analysis using an unstimulated horizontal well model are shown in figure 14. The model predicted a reservoir pressure of 23,859 KPa, which would normally be associated with good productivity, so supporting the theory that the well performance impairment was not due to offset interference and
depletion from the child well. However, the model also generated a skin factor of +3.8, indicating that near wellbore damage due to offset frack communication is certainly a factor. This interpretation is supported by the surprising lack of fracture and linear flow indications on the derivative plot. The best-fit model was that of an unstimulated well with very low intrinsic permeability after being damaged by offset child well fracks.

Rate transient analysis (RTA) was then performed on the well’s production and pressure data prior to the frack communication in 2015. In this case, the expected multi-stage horizontal model gave the best fit and yielded in-situ permeability 2 orders of magnitude higher than the post frack PTA. This reduction in permeability from the pre-damage RTA to the post-damage PTA supports the theory of near-wellbore damage resulting from frack communication. As discussed, depletion and interference were not evident during the flow and build-up analysis, and so it was concluded that there is a clear reduction in inflow performance due to damage in the parent well.

Identifying Damage Mechanisms in the Case Study Parent well

Using the reservoir characterization workflow described previously to predict when and where frack communication is likely to occur between parent and child wells is critical in identifying “at-risk” parent wells. Following validation and quantification of the damage seen in these parent wells using RTA and PTA, the next step in developing a mitigation strategy is to understand the damage mechanism(s).

In addition to the analytical tools discussed to this point, it is critical that subsurface, operations, and completions teams work collaboratively to collect samples that may provide clues to parent well damage mechanisms. In the case of the c-27-H/94-B-8 well, a sample was recovered during swabbing operations that provided an important piece of data which helped to understand parent well damage mechanisms in the Montney. A picture of the debris recovered from the damaged parent wellbore and its compositional breakdown is shown in Figure 16 below.

![Image of Montney Wellbore Debris and Compositional Breakdown](image)

Through a series of extensive laboratory tests, including gas chromatography, x-ray diffraction (XRD), x-ray fluorescence (XRF), scanning electron microscope (SEM) imaging, and visual inspection by microscope, the composition of the debris was concluded to be predominantly frack sand, asphaltenes, iron oxides, and mineral fines from the Montney formation.

Other samples were recovered at various stages of the gas gathering and processing system that had a similar appearance and were confirmed to be of similar composition. A more detailed description of the determination of the debris composition is described below.

Initially, gas chromatography (G.C.) was performed on the hydrocarbon component of the debris recovered from the damaged parent well and on the plant solids to try to ascertain its origin. The result is shown in Figure 17. The composition of the hydrocarbon component appeared to be heavier than produced condensate and was concluded to be asphaltene deposited from the reservoir fluids during production. The debris is thought to be “swept” into the
proppant pack and near wellbore region during offset child well frack communication, contributing to the formation
damage and consequent loss of production in the parent well.

![Figure 17: GC Analysis of Hydrocarbon Samples](image)

In order to evaluate remediation options, a series of laboratory tests were performed to determine the solubility of
the hydrocarbon component within the debris. The sample was found to be insoluble in produced condensate at
reservoir temperature (163°F), but soluble in both xylene and toluene.

The second component of the debris analyzed was the solid material identified as proppant and formation fines.
XRD and XRF were used to identify the key components of the solid material. The sample consisted predominantly
of silica (proppant), halite, calcite, and greigite. Of these components, the presence of oxidized iron was not
anticipated to be a major concern, but upon SEM imaging, it became evident that the oxidized iron was playing an
important role in the damage of parent wells. Figure 18 shows both an SEM image of a grain of proppant coated by
iron oxide and XRF showing elemental composition of the debris and its tentative mineral composition. The iron
oxides act as cement for fine material within the produced debris, aggregating crushed proppant pieces. In addition,
the iron oxides are nucleation sites which agglomerate the asphaltic material, permitting the heavy hydrocarbon to
grow into large enough solids to be swept by frack water. The combination of these processes allows iron produced
by the formation to form debris within the fracture network that contributes to parent well damage. (Etienne 2018).

![Figure 18: SEM Image of Silica and Iron Oxide (left) XRF histogram showing mineralogy (right)](image)
The third component of the wellbore debris was silica, which was predominantly proppant. The flow back of proppant after an offset frack hit is thought to occur due to fluids sweeping the proppant pack. Upon visual inspection, a significant percentage (up to 20%) of the proppant was crushed. Crushing results in a reduction in proppant pack permeability and wellbore conductivity, which can be compounded if downhole stress is cycled due to repeated frack hits.

Based upon all the tests and analyses described, the most likely causes of reservoir damage in the c-27-H/94-B-8 case study well are asphaltene deposition and fines migration, combined with proppant pack damage. This parent well has yet to recover from the damage caused by communication with the offset child wells.

**Future Mitigation of Parent Well Damage**

Although remediation is an option to address damaged wells, prevention of damage is the preferred approach. Remediation tends to be expensive, technically and operationally challenging, and does not address proppant pack damage discussed above. For these reasons, prevention rather than remediation of parent well damage is the preferred approach.

Both Canbriam internal and public studies have shown that optimizing field development plans is an effective way to protect parent wells from damage by reducing the time between parent and child wells. While this is an approach actively utilized at Canbriam, there are times when parent/child frack communication is unavoidable due to timing of development drilling and Canadian ‘break-up’ downtime. For this reason, developing mitigation strategies is an essential component in the overall strategy of protecting parent wells from damage due to offset frack communication. We have established that reservoir characterization is fundamental to identifying where frack communication is most likely to occur. Given this fact, Canbriam then tried a mitigation technique which is summarized in figure 19. The initial step is to shut the parent well in for at least 2 weeks to allow reservoir pressure to build up from the depleted pressure level. This higher pressure ‘halo’ somewhat reduces the severity of the direct communication caused by the child well completion. Next, the parent well is pressured up by injecting water into the wellbore. Importantly, based upon the damage identification work described previously, the ‘pressure pump-in water’ has optimized frack chemistry with chelation to remove iron and reduce the formation of the black debris seen in the case study well, (Etienne, 2018). This pump-in induces another higher pressure halo around the wellbore, shown in figure 19, which further reduces the ability of the child well completion to reach and therefore damage the parent well. The reduction of ‘child’ frack fluid into the ‘parent’ well bore helps prevent any associated damage caused by debris accumulation and disturbance of the proppant pack. These mitigation measures resulted in more symmetrical fracks in the child and vastly reduced pressure communication with the parent. The difference is clearly shown in figure 20 below. The figure illustrates a parent well in which the mitigation technique has been applied
over half the well. On the left of the figure, from the 28th to the 31st of August, the large casing pressure spikes, monitored using real-time pressure, are as a result of unmitigated direct communication with an offsetting child well. Some of these pressure spikes are greater than 15MPa and represent direct communication along a previously characterized fracture cutting the wellbore. In this case both pressure and increased water were seen on parent well flow-back.

On the right hand side of the plot, from September 1st to 3rd, the mitigated casing pressure has been elevated by pumping in a 400 cubic meter fresh water pill, with iron control and flowback enhancer. There are now only slight indications of pressure communication from the child well. This has been attempted in more than 15 parent wells since this time, all showing lower pressure communication with child wells.

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Figure 20: Parent-Child well Mitigation techniques

Figure 21: Recent results of parent well mitigation – 13 wells
Another finding from this work is related to water flow back. Once wells have been completed, in most cases, the child wells have higher pressure than the original parent well. Consequently they will be able to move flow back water from the formation more efficiently than the lower pressure parent well. For this reason, the child wells are always flowed back before the parent wells so that water flows away from the parent well, thereby reducing further accumulation of debris.

Production rate recovery using the mitigation techniques has been excellent. The green circles in figure 21 illustrate parent well flow rates before and after child well frac communication in the mitigated wells. An example of an earlier unmitigated well, red circle, is also shown for comparison.

Conclusions

The following conclusions have emerged as a result of this work;

- Understand the reservoir. Integrated reservoir characterization is critical to be able to predict likely interference between parent and child wells.
- Mitigation of parent – child interaction is preferred. Though laboratory work has highlighted the likely cause of the parent well damage, practicalities of pumping xylene or toluene into the wellbore at high pressure make remediation at best very difficult.
- The biggest factor in parent-child well interaction is time between the flow back of the parent well and fracking of the child well. The longer the parent produces, the more the pressure draw-down and asymmetrical the child completions are likely to be, leading to more parent well damage.
- Shutting in the parent well for as long as practicable, at least 2 weeks, helps to reduce the pressure draw down in the surrounding area.
- Pressure pump-ins have worked extremely well in Canbriam’s Altaires Montney. The optimum recipe is to pump in 400 cubic meters of fresh water with frac chemistry, predominantly to reduce iron, which has led to the formation of black debris in the wells.
- Pressure protection of the parent well reduces stress cycling on its proppant pack. Stress cycling leads to proppant crushing and mobile fines, both of which can lower well deliverability.
- Parent wells are always cleaned up after the child wells to minimize the amount of water that the lower pressure parent well has to move.

Acknowledgements

The authors thank Canbriam Energy for permission to release this paper. Thanks are also due to all the members of Canbriam’s operations and subsurface teams, most of whom have been involved in this integrated work.

References


