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Indirect Hydraulic Fracturing in Coalbed Methane and Coal Mine Methane Applications: Not All Parent-Child Well Interactions Have Negative Consequences!

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Abstract

Surface-to-Inseam (SIS) wells have been used in Eastern Hemisphere, Coalbed Methane (CBM) developments and Coal Mine Methane (CMM) pre-drainage or emission reduction applications. However, as wells encounter low-permeability, highly compartmentalised coals, increasing the Stimulated Reservoir Volumes (SRVs) are essential to achieve effective commercial recoveries. Indirect Hydraulic Fracturing (IHF) is proposed as a key enabler for existing CBM and CMM applications in low-permeability coals. This study is based on studies and modelling of initiation mechanics and field-proven workflows for implementation. This study integrates DFIT-calibrated modelling and mine-back verification to demonstrate IHF as a practical solution for compressive stress states or areas of overlapping mining tenures.

Vertical coal stimulations in low-permeability seams often face near-wellbore pressure loss, fracture complexity, and limited effectiveness. Micro-proppants improve treatments in pressure-dependent environments, but far-field compartmentalization still limits SIS recovery. To address this, five Indirect Hydraulic Fracturing (IHF) wells—2 vertical and 3 horizontals—were drilled and fracs initiated below target seams. Workflows included 1D stress profiling, reservoir modelling, and 3D fracture designs to optimize stage spacing and treatment schedules. Horizontal wells used 40–50 m sleeve spacing, mini-fracs for leak-off calibration, and strict QC to prevent over-flushing. Diagnostics such as microseismic, SIS pressure monitoring, and tracers confirmed interconnectivity and SRV expansion.

Across 55 frac stages (53 in three horizontal wells and 2 in vertical wells), no screen-outs occurred, with only one failed stage which was over-flushed. Treating pressures showed negligible near-wellbore effects except at proppant loads >6 lb/gal. Mine-backs of two vertical wells revealed simplified fracture geometries and no roof complexities, contrasting with documented cases of extensive fracture complexities in the literature. Horizontal wells achieved strong interconnectivity and boosted recovery in offset SIS and vertical wells. Modelling confirms strategic IHF placement within SIS frameworks improves long-term recovery and economics, with sensitivity guiding optimal stage count and SRV expansion.

This paper unifies IHF research, field observations, and mine-back case studies into practical, field-proven workflows for low-permeability CBM or CMM stimulations. It demonstrates how DFIT-calibrated modelling, multi-stage horizontal designs, and diagnostics such as microseismic and tracers improve understandings of the Stimulated Reservoir Volume (SRV) and recovery in Coalbed Methane (CBM) and Coal Mine Methane (CMM) projects. Applications address Eastern Hemisphere challenges—high stress, compartmentalization, and mining overlap—while enabling co-application with Surface-to-Inseam (SIS) wells, integration of micro-proppants, and optimized staging to enhance economics, safety, and emission reductions. IHF is suitable for initial or infill applications.

Introduction

Australia has over two decades of successful CBM developments, but has struggled to develop low-permeability, highly compartmentalised coals. Research has specifically focused on defining PDP behaviour and evaluating technologies to enhance the SRV for better appraisal of these resources (Johnson Jr, 2024). Vertical well stimulation in coals has been met with significant near-wellbore difficulties, particularly with respect to placement of hydraulic fractures in low-permeability coals. Surface-to-Inseam (SIS) horizontal wells have demonstrated an inability to drain highly compartmentalised or low-permeability coals adequately without supplementary stimulation (Johnson et al. 2021, Ramanandraibe et al. 2023). Low-permeability coalbed methane [CBM or coal seam gas (CSG)] wells generally require stimulation to achieve commercial production rates. Key factors associated with the success or failure of a low-permeability CBM development are often centred around pressure-dependent permeability (PDP) behaviour, fracture effectiveness, and overall Stimulated Reservoir Volume (SRV). These factors are interrelated and involve similar workflows to deconstruct key influences on their success or failure (Johnson Jr., You, et al. 2020).

For the purposes of this paper, Indirect Hydraulic Fracturing (IHF) is defined as the initiation of a hydraulic fracture from a wellbore placed in the clastic interval underlying (or, less commonly, overlying) the target coal seam, such that the fracture propagates from the higher-stress clastic into the adjoining lower-stress coal with a more simplified geometry than would be obtained by direct initiation in the coal (Johnson Jr., Cheong, et al. 2020; Johnson et al. 2021). The IHF wellbore is typically drilled 2–4 m below the base of the seam, with intermittent 'floor touches' into the coal where required to maintain wellbore-to-fracture connectivity, and is completed with a steel liner, external packers and frac sleeves placed entirely outside the mineable seam. This completion strategy is particularly important in Coal Mine Methane (CMM) applications, where conventional steel-cased completions within the seam are precluded by longwall mining hazards (Johnson and Ramsay 2024).

In the CMM co-application context that is the focus of three of the field cases presented here, the IHF well is deployed into a pre-existing pattern of predrilled SIS wells (Johnson et al. 2021; Ramanandraibe et al. 2023; Johnson and Ramsay 2024). Using the now-common North American shale terminology, the predrilled SIS wells therefore act as the "parent" wells in the drainage pattern, and the later-deployed IHF lateral functions as the "child" well, with its multi-stage fracture network designed to intersect, extend and interconnect the SRV being drained by the existing SIS parent wells and any subsequent offsetting SIS or Underground-to-Inseam (UIS) wells. Whereas in unconventional shale developments such parent–child interactions are widely associated with negative outcomes (e.g., depleted-zone 'frac hits', asymmetric fracture growth toward depleted parents, and impaired child-well productivity), the field evidence from the Bowen Basin IHF applications discussed in this paper indicates that the IHF child does not impair the predrilled SIS parents and, in many cases, materially enhances their productivity — hence the title of this paper.

This paper brings together key findings from five CBM and CMM studies spanning the development and application of IHF in three Australian basins (Cooper, Surat, and Bowen) as well as recent work on the sensitivity of variables in IHF implementation and production data. The paper is structured to present: (1)

the reasoning and methodology developed through initial applications; (2) implementation guidelines based on field-proven workflows; (3) a sensitivity analysis of key variables affecting IHF performance; and (4) modelling of potential next steps**,** including micro-proppant co-application for both CBM and CMM applications.

Indirect Hydraulic Fracturing Implementation

Initial IHF Cooper Basin Application: Strike Energy, Jaws 1ST Well

The first successful application of horizontal IHF was at Strike Energy's Jaws 1ST well in the Weena Trough, Cooper Basin (Branajaya et al. 2019, Johnson Jr., Cheong, et al. 2020). The Jaws 1 inseam wellbore experienced caving and a pack-off around the drill string**,** attributed to wellbore instability, followed by a loss of the bottom hole assembly (BHA). The side-tracking and redrilling of Jaws 1ST commenced, placing a 726 m lateral directly beneath the Patchawarra Vu coal interval — a laterally extensive 30 m coal seam at approximately 2,000 m depth (Figure 1)**.**

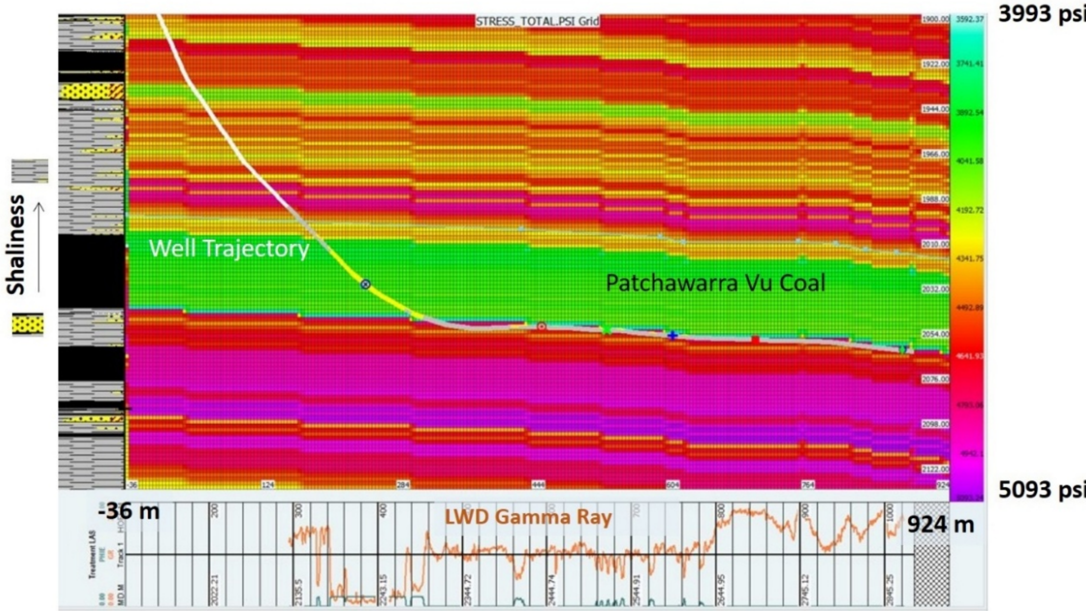

Figure 1: Jaws ST1 Well Trajectory and Stress Profile Derived from DFIT data (after Johnson Jr., Cheong, et al. 2020)

Prior to the treatment, a pressure-activated toe sleeve allowed calibration of the stress profile using a pre-frac DFIT; however, the toe DFIT communicated directly with the Klebb 5 intercept well, exhibiting a low ISIP of 3,776 psi (0.56 psi/ft gradient), comparable to the 0.57 psi/ft closure gradient observed at the offset Klebb 4 DFIT. The higher 0.68 psi/ft average closure gradient observed during Stages 4 and 6 mini-fracs likely represented the indirect connection closure or a less destressed region. These data, combined with the Klebb 4 multi-interval DFIT, were used to calibrate the 1D stress profile for the treatment design.

The Jaws 1ST horizontal well was completed with a 5½-inch liner with seven frac sleeves, each isolated with an open hole packer on either side. A total of one million pounds of proppant were placed successfully across all seven fracture stages, with individual stage totals ranging from 112,000 to 152,000 lbs. The fracture stimulation was monitored using a real-time downhole microseismic monitoring array placed in Klebb 4 and an array of 38 surface deformation tiltmeters surrounding Jaws 1ST in a 6.4 km² racetrack pattern. Chemical tracing of each stage with individual liquid tracers provided insight into placement and effectiveness (Johnson Jr., Cheong, et al. 2020).

Fracture diagnostics concluded that no singular methodology was adequate to describe the fracturing process fully: microseismic provided reasonable geometry estimates but yielded lower magnitude events in coals; tiltmeters indicated low-level horizontal responses suggesting natural fracture interaction and a dilatancy effect rather than the conventional T-shaped fracture interpretation; and liquid tracers provided the ground-truthing of production by stage, revealing that Stages 4, 6, and 7 contributed to most heel production while Stages 1–3 were predominantly recovered via the Klebb 5 intercept well. Stage 1 tracer was also produced at the Klebb 1 wellbore, indicating interconnection of the SRV with partially depleted natural fracture systems being drained by other wells. Collectively, the Jaws 1ST results confirmed IHF as viable in strike-slip stress regimes when wellbore placement and the stress and rock mechanical contrast between the coal and adjoining clastic are adequately characterised.

IHF Vertical Well Implementations: Bowen Basin, Moranbah North Mine, Moranbah, QLD

The key in IHF implementation in Moranbah North Mine was to enable more effective direct drainage of gate roads to enable UIS drilling to complete drainage left by unsuccessful SIS drainage wells. Johnson et al. (2021) presented a more detailed analysis of the first vertical well implementations of IHF, targeting the GM seam in the Bowen Basin on two vertical wells (SO774 and SO782) in the Moranbah North My area. Due to mining constraints, no steel components could be placed in mineable sections of the drainage wells. The vertical well was cased with glass-reinforced epoxy and cemented back across the coal with a steel frac sleeve placed 2 m below the coal, outside the mineable section. A DFIT was performed on the well to calibrate the stress profile (Fig. 3a), and the frac effectively placed the desired amount of proppant in the formation. The range of stress values in the undrained floor and strike-slip regime was similar to those observed following DFIT testing in an offsetting area (Pallikathekathil et al. 2013). However, localised mining was believed to be the result of lowered stress in the floor or area below the seam (and likely some in the roof area), unlike published profiles, which were in undrained regions east of the MNM.

The fracture zone surrounding the treatment borehole SO774 was eventually exposed during the longwall retreat and identification of fractures by Geotechnical Engineer inspections. Unmistakable evidence of intersections along the coal face (see black dots, Fig. 3b) indicated a dominant fracture in the general maximum horizontal stress direction (NNE to NE) with minimal orthogonal fractures, hypothesised as the result of initiating the fracture outside of the coal. The fracture trend remained aligned to σ_{HMax} despite significant depressurisation and stress relaxation, creating near-isotropic horizontal stress values at this location, believed to be the result of permeability anisotropy of the dominant natural fracturing also striking the NNE to NE direction (Johnson et al. 2021). The onsite geotechnical engineer and the overseeing geotechnical advisor both viewed the mined-back fracture underground. They observed no destabilisation of the roof or floor and complexity only in an area of known fault (Personal Communications**:** Prof Ismet Canbulat, AU-CN Decarb, Xuzhou, China 2025**,** Anglo Geotech Engr, Resource Operators Conference, Springfield QLD, 2025).

With this success, a second vertical well, SO782, was drilled and stimulated successfully. Development mining operations also intersected the treatment zone in SO782 with exposure of fractures aligned to the general σ_{HMax} direction. The second IHF trial fracture zone has remained exposed by mining development activities since its intersection in October 2020, and open roadway intersections have remained structurally stable. Additionally, evidence of fracture zone interaction with the coal seam underlying the GM seam, the GM Lower seam (GML) was identified in SO782 by geotechnical and gas monitoring compliance inspections, indicating potential destressing of lower seams and resulting in their release of gas content — another beneficial outcome of IHF stimulation in the floor (Johnson et al. 2021, Johnson and Ramsay 2024). Neither vertical well was produced prior to mining.

Second IHF Horizontal *Well Implementation: Bowen Basin, Moranbah North Mine, Moranbah***,** *QLD*

After two successful vertical well trials, the first horizontal IHF implementation in the Bowen Basin was the SG608-01 well, planned and executed below a planned gate road in the longwall mine targeting the GM seam. This application was placed amid existing SIS wells to ascertain the potential co-application of IHF and SIS to enhance mine gas pre-drainage. The lateral was targeted 2–4 m below the seam with several floor touches to maintain standoff from the seam (see Fig. 17, Johnson et al. 2021). Based on hydraulic fracture modelling of stress shadow effects in the floor sections, sleeve spacing was set at 40 m with omissions in areas of geotechnical concern, and the resulting treatment schedule was based largely on the pumping schedule used in the S0774 vertical well. As this treatment was being performed on a mine site, limited access precluded coiled tubing from being readily accessible in the case of a screen out; as such, a thorough pre-job QC process was implemented including a decision protocol for each frac execution in the event of abnormal pressure responses, and a pre-frac mini-frac was conducted for each stage to review and adjust volumes based on observed fracture efficiency and pressures. A DFIT was performed at the first sleeve location to calibrate the stress model and adjust the leak-off. The resulting 23-stage treatment was successfully placed over seven days (Johnson et al. 2021, Johnson and Ramsay 2024). The resulting fracture dimensions, locations of offsetting SIS wells, and microseismic responses can be seen in Figure 2

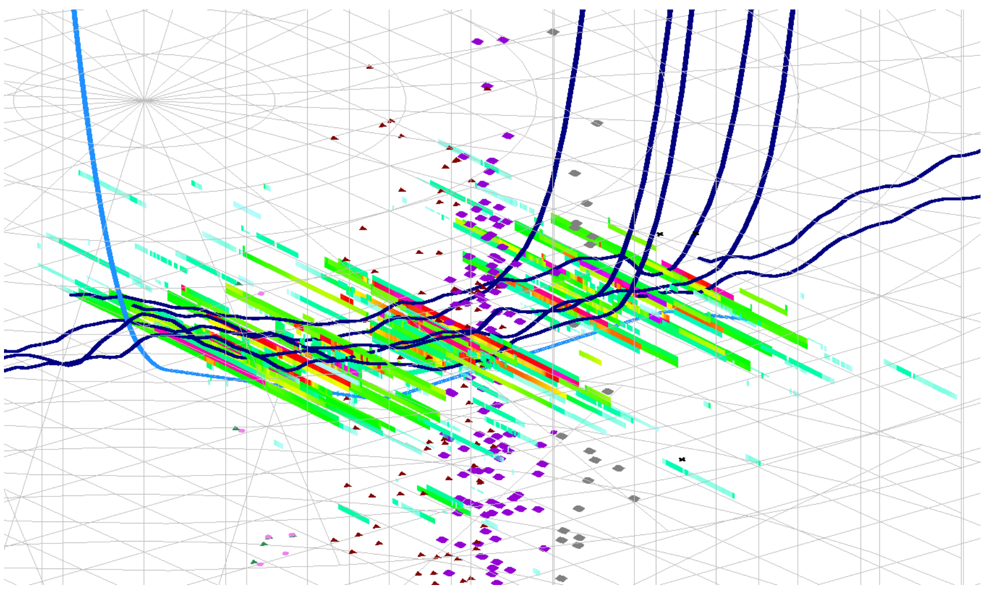

Figure 2. SG608-01 well and SIS wells trajectory with hydraulic fracture conductivity and microseismic events (after Johnson et al. 2021).

All stages were modelled, and the fracture lengths determined based on a cut-off of >0.5 lb/ft² or >5 mDft conductivity (light blue colour, Figure 2). In almost all cases the model-predicted surface and calculated BHTP values exceeded the observed pressures even with large reductions in frictional components, attributed to clastic/coal interface effects, well branch connections to the coal, and variability in the underlying clastics not captured by a single reference well log (Johnson et al. 2021). To evaluate the post-fracture results, microseismic data were collected through the job from a vertical well located SE of the toe. These data indicated a low distribution of events in the GM Seam and a predominant distribution of events higher and lower than the GM seam.

Low incidences of micro seismic events in the coal and anomalous events outside the coal have been noted by diagnostics in the WCM, as well as examples in North America (Barree 2009, Flottman et al. 2013, Johnson et al. 2010, Zimmer 2010). The authors hypothesise that most of these upper and lower events were unrelated to the fracturing treatment or were shear events related to the high degree of depressurisation and destressing of the lower and upper clastics around the GM Seam because of the adjoining mineworks.

*Third IHF Horizontal Well Implementation: Bowen Basin, Moranbah North Mine, Moranbah***,** *QLD*

The SG609-02 well, the second Bowen Basin horizontal application, extended IHF to an undrained portion of the mine. Anglo planned two IHF wells along the 609 panel, designed to manage up to 30 stages based on their length and the successful spacing of 50 m between prior frac stages in SG608-01. Eventually, the plan *was* adjusted to only stimulate SG609-02, a northward extending IHF well along two directly offsetting SIS wells and several SIS wells south with toes near SG609-02**.** An observation well mid-lateral and east of the IHF well was selected for micro seismic monitoring. Based on pre-well signal determinations, it is likely that most observations beyond Stage 16 could be outside the radius of investigation of the current observation well and would require the placement of a second observation well, optimally placed westward and closer to the heel.

Rock mechanical properties and geologic data were derived from offsetting vertical well log data, sonic velocity relationships from previous 1D stress profiling (Johnson et al. 2021, Pallikathekathil et al. 2013), and physical mapping of the offsetting well trajectories within the coal seam. Tectonic strains were used from prior 1D stress profiles. A DFIT was performed from the toe and first sleeve; the toe sleeve communicated with the vertical well, however a clear analysable closure pressure was observed in Stage 1. For this case, the 1D stress profile required adjustment to account for the lack of depletion in the 609 panel (Figure 3). The well was drilled 2–3 m below the GM seam, intercepted a vertical well, and had 12 vertical floor touches to aid drilling and fracture interconnection. It should be noted that the greatest separation between the IHF well and the seam was in the middle of the hole; this may be the cause of the greatest deviation between observed and modelled post-frac pressures (Johnson and Ramsay 2024).

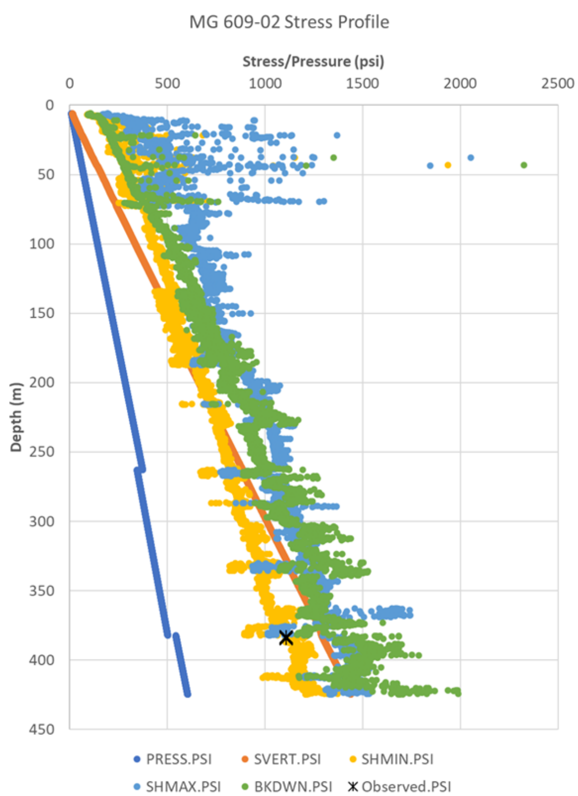

Figure 3. Development of log-derived 1D stress profile for SG609-02 based on observed DFIT closure (black asterisk) and estimated reservoir pressure with minimal depletion (dark blue trace) (after Johnson and Ramsay 2024).

One fluid injection and 23 proppant-laden stages were pumped. Treatment pressures were higher than those observed in the previous SG608-01 lateral, likely because of lower pre-frac depletion. Days 1–4 or the first 16 stages closely resembled the predicted pressures (Figure 4).

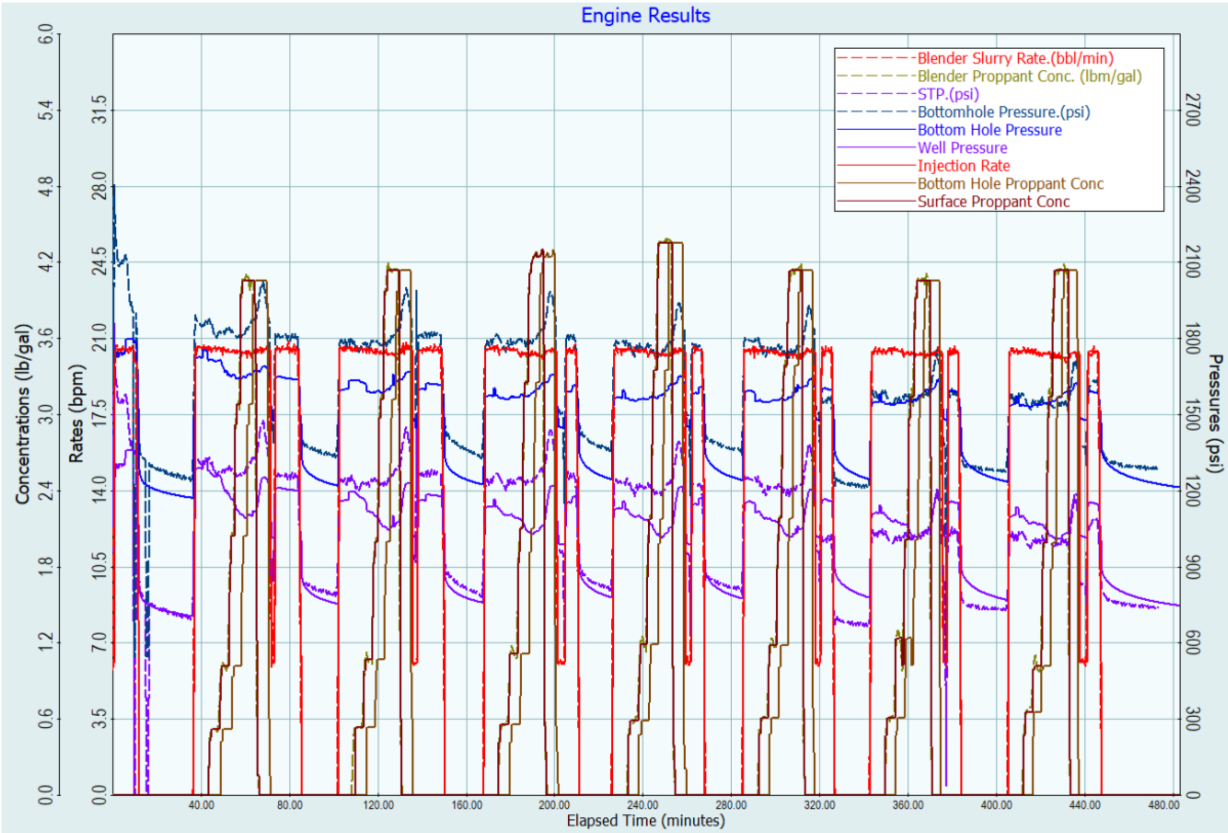

Figure 4. Treatment pressure history-match of observed surface and model-predicted pressures, surface and downhole proppant concentrations, injection rate, and model-predicted and surface-calculated bottom hole treating pressures for Day 4, Stages 10–16 (after Johnson and Ramsay 2024).

Days 1, 2, 4, and 5 all produced good transverse fractures, achieving the targeted 4 lb/gal proppant concentration, resulting in a downhole concentration greater than 0.5 lb/ft². The model predicted that Day 3 (Stages 5–9) produced some longitudinal components in addition to transverse fractures (Figure 5); this region corresponded to the greatest separation between the seam and the IHF well and was consistent with micro seismic events closely adjacent to the IHF wellbore beginning in Stage 5 (Figure 6).

IHF/SIS Well Interconnections and Post-Stimulation Results

SG608-*01 IHF/SIS Well Interconnections and Treatment Results*

Throughout the treatment, pressure, fluid, and sand influx were noted in varying SIS and pressure observation wells during various stages, confirming that interconnections to the SIS wells were successful. The post-frac modelled dimensions met or exceeded the pre-frac modelled dimensions (Figure 7a), whilst the SRV estimated from interconnections observed in offsetting SIS and observation wells (yellow region, Figure 7b) exceeded the modelled SRV (red region, Figure 7b) This breadth of fracture-created length was corroborated by the evidence of lengthy fractures in the Jaws 1ST IHF treatment application, interconnecting with previous vertical wells. Offsetting SIS wells showed production improvement post-frac. An offsetting SIS well was analytically history-matched prior to the frac operations, anchoring the model on the observed gas rate data and honouring the pre-frac BHFP. Post-frac, the forecast could not match the observed gas rates**.** It would not be achievable in the model without invoking a negative BHFP, indicating that the frac improved the SIS well lateral length, increased permeability, decreased skin, or increased drainage area (Johnson et al. 2021; Johnson and Ramsay 2024).

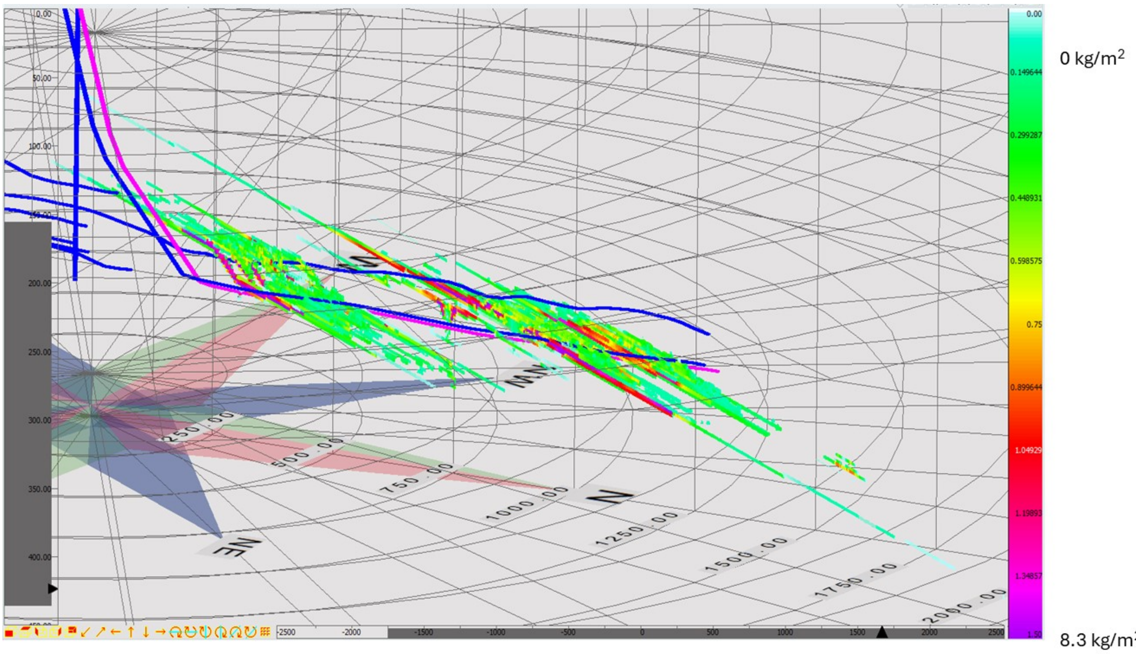

Figure 5. Graphical representation and distribution of propped fractures around IHF well (magenta) and adjoining SIS wells (blue) (after Johnson and Ramsay 2024).

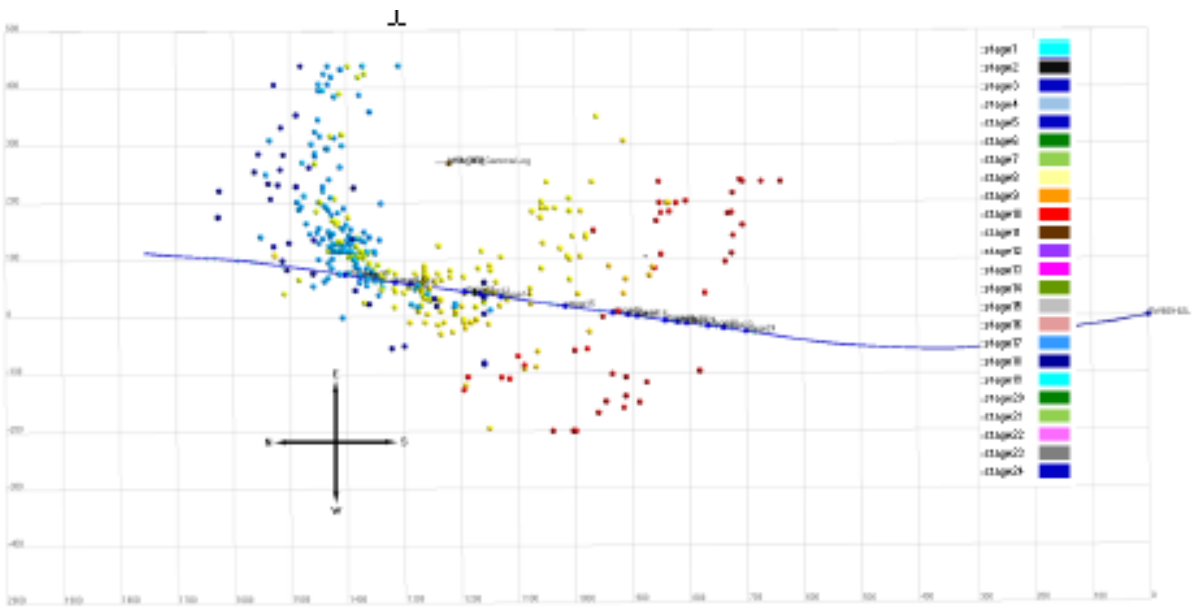

Figure 6. Map view looking East of the microseismic events located during the 24 stages of the stimulation of the IHF well (after Johnson and Ramsay 2024).

Other SIS wells indicated anecdotal decreases in decline post-frac, but operational difficulties and inability to work over offsetting SIS wells meant that UIS drilling was still required to achieve the desired drainage targets within the mining timeframe.

Anecdotal evidence from UIS wells in the 608-panel adjoining the initial IHF well indicated that the panel may have been stimulated based on an increase in both UIS and the IHF well productivity relative to offsetting and unaffected SIS production wells (Table 1).

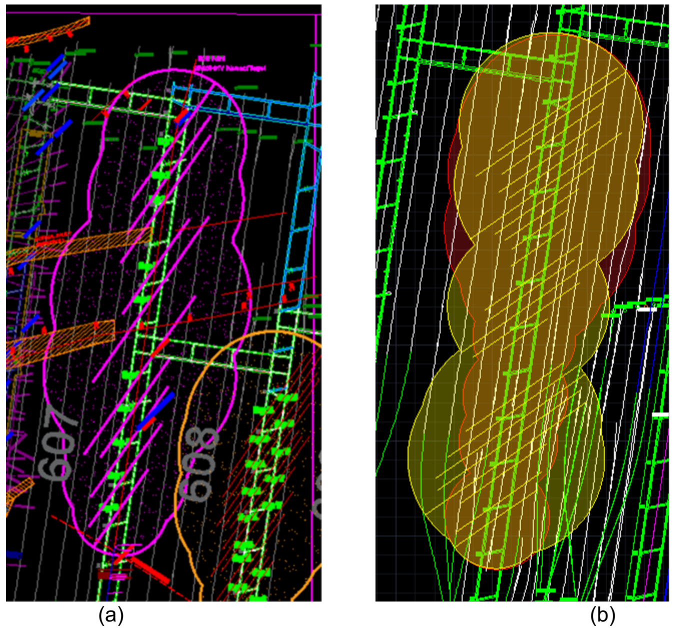

Figure 7: (a) SG608-01 well trajectory (solid red line), pre-frac modelled hydraulic fracture lengths and SRV (magenta lines), SIS wells (grey lines), planned mine gate road (light green lines), and post-frac modelled hydraulic fracture lengths and SRV (magenta outline); and (b) post-frac modelled SRV (red region) and the region of disturbance observed in offsetting SIS and observation wells (yellow region) (after Johnson et al. 2021).

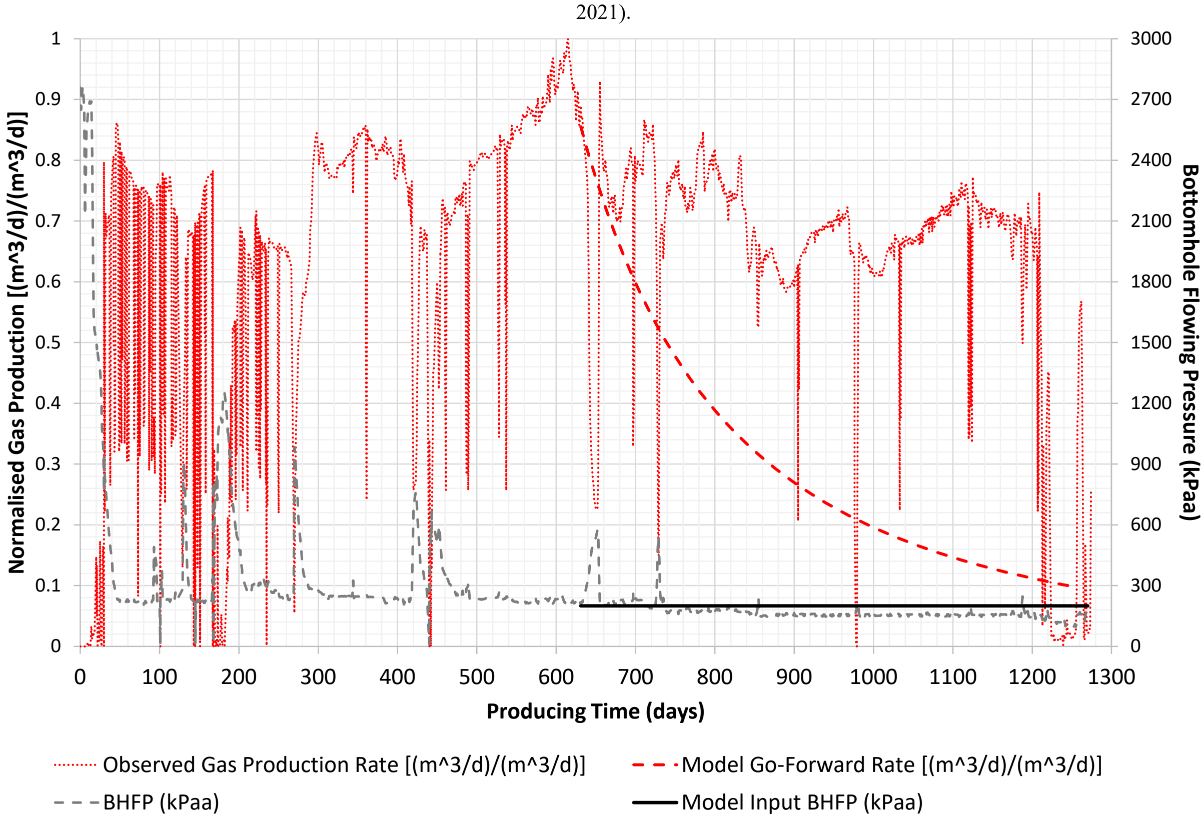

Figure 8. Production history from SIS well offsetting SG608-01 Well, then model-predicted actual versus forecast gas production (after Johnson and Ramsay 2024).

Table 1. Normalised Comparison of Well/UIS pattern production on adjoining panel to initial IHF well.

Well/UIS pattern	Panel	Production start date	Days on production	Normalised average flow rate per day [(m^3/day) / m^3/day)]	Normalised cumulative volume (m^3/m^3)
SIS 1	607	26/03/2019	1427	12%	30%
SIS 2	607	5/04/2019	1417	40%	98%
UIS 1	607	27/12/2020	339	74%	100%
IHF Well[1]	608	21/12/2021[2]	781	51%	30%
UIS 2	607	18/08/2021	550	89%	84%
UIS 3	607	18/11/2021	460	100%	79%

[1]Available data is only available for the first 339 days of production post frac and dewatering; [2]Fracture stimulation was performed on 18/2/2021 before installation of UIS patterns 2 and 3, and shortly after pattern 1.

On a normalised basis, the SIS wells in the panel achieved 12% and 40% of the normalised average daily flow rate, while the IHF well achieved 51% — comparable to the UIS wells at 74–100%. The first-year production of the IHF well approached the same cumulative volume as the worst-performing UIS well with similar permeability and pressure data, despite having been fractured before the installation of UIS Patterns 2 and 3 and shortly after Pattern 1 (Johnson and Ramsay 2024). Neither the IHF well nor the adjoining SIS wells were produced independently of the UIS pattern; therefore, the full extent of the IHF co-application benefit on standalone SIS drainage remains to be quantified.

SG609-02 IHF/SIS Well Interconnections and Treatment Results

The SG609-02 treatment provided the first opportunity to evaluate IHF performance in an undrained panel with higher reservoir pressures and minimal stress relaxation from prior mining or production. The key observations and contrasts with the SG608-01 case are as follows.

Unfortunately, the two SIS wells directly adjoining the IHF well did not have pressure monitoring; however, there was a strong indication that these wells were interconnected by propped fractures based on modelled dimensions (Figure 9) and micro seismic events (Figure 10). Two SIS wells adjoining the heel were equipped with pressure monitoring and experienced responses during Days 2 and 4 that were not predicted by the fracture model (Figs. 9 and 10). On Day 2, SIS well 609-09 experienced a pressure response early during Stages 2–4; proppant profiles did not indicate that the frac hit was likely to be proppant-laden (Figure 9). Similarly, SIS well 609-12 experienced a pressure response early on Day 3 during Stages 5–9, which had indications of longitudinal components that may be closely aligned with the heel-oriented 609-12 lateral (Figure 10).

Conjugate fracturing and fracture complexity are not uncommon in coal frac treatments, and small-width fractures may extend to great lengths. Still, they may not remain open without the implementation of micro-proppants less than 50 μm (Keshavarz et al. 2016). This illustrates the value of pre-configuring the adjoining SIS wells with pressure monitoring prior to IHF treatment. Further, offsetting fibre-optic configured laterals may give greater confidence than micro seismic monitoring on fracture propagation by measuring strains created by the fractures, akin to surface deformation tiltmeter measurements (Bourne et al. 2021, Johnson and Ramsay 2024).

The SG609-02 results, combined with the SG608-01 observations, demonstrate that IHF fractures consistently interconnect with offsetting SIS wells in both previously drained and undrained panels. The unpredicted pressure responses in heel-adjacent SIS wells indicate that the created SRV may exceed the planar 3D model-predicted dimensions through conjugate fracturing and natural fracture interaction — effects that are not captured by current modelling approaches but are observable through pressure monitoring. The SG609-02 case reinforces that pre-positioning SIS wells with pressure monitoring within the anticipated IHF interconnection radius is essential for verifying fracture growth and quantifying the true extent of the SRV (Johnson and Ramsay 2024). A key learning from this study is that comparing adjacent or affected SIS wells on a normalised average rate or cumulative basis do not indicate production impairment by IHF implementation and interaction within SIS patterns (see Table 2). In fact, in under produced areas, affected wells performed better than offsetting non-adjacent wells, despite comparable offsetting wells are shallower where there is anecdotal evidence for increased permeability and similar average production starts and durations than outbye wells.

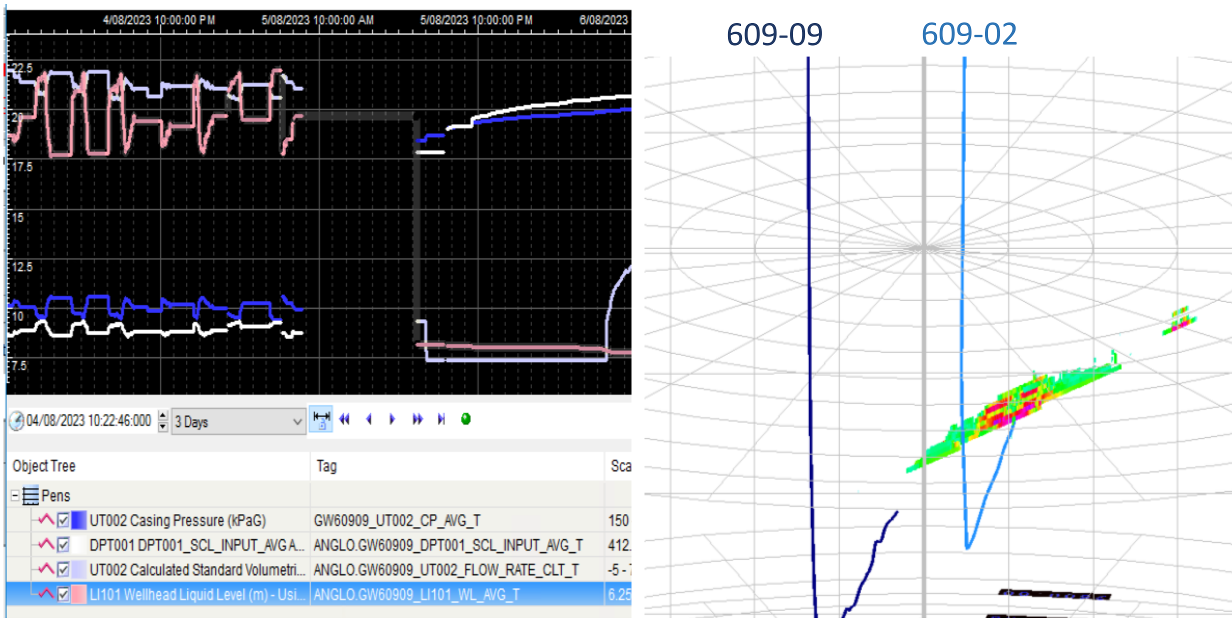

Figure 9. *Pressure responses during Day 2, Stages 2–4 (left) in offsetting SIS well 609-09 (right) (after Johnson and Ramsay 2024).*

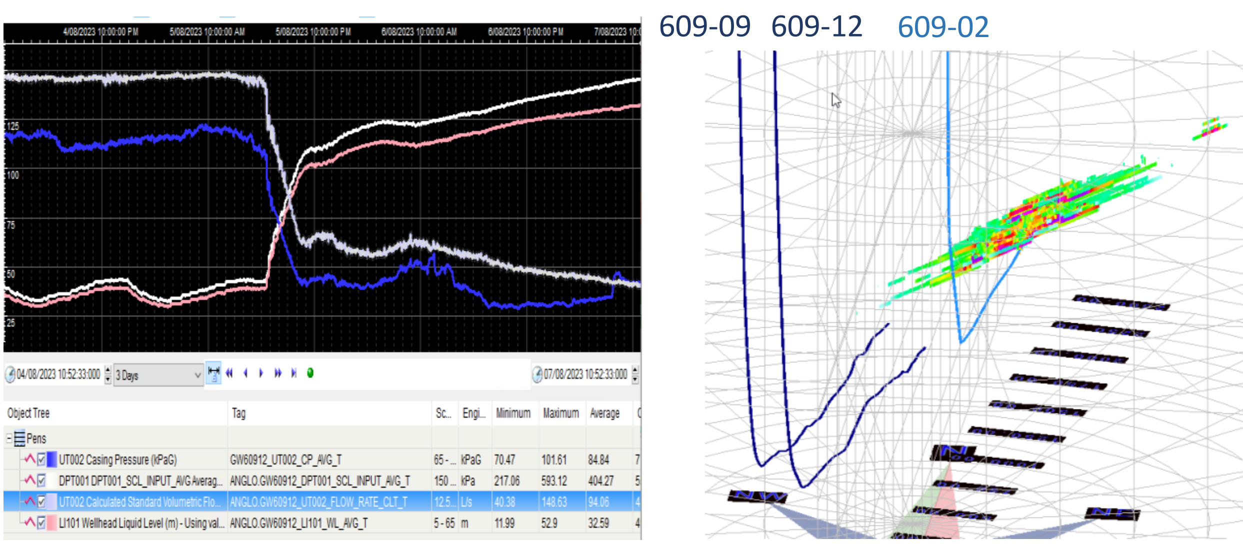

Figure 10. *Pressure responses during Day 4, Stages 5–9 (left) in offsetting SIS well 609-12 (right) (after Johnson and Ramsay 2024).*

Table 2. Normalised Production Comparison of Offsetting (1-2 spacing) to Non-Offsetting (>2 spacing) SIS Wells IHF Wells

Panel	Location	Normalised average producing days (days/days)	Normalised average flow rate per year [(m^3/yr) / m^3/yr)	Normalised cumulative volume (m^3/m^3)
Existing Wells 608/609 Panel	Offsetting IHF	1.31	1.05	1.00
	Non-Offsetting	1.36	1.00	1.42
Initial Wells 609/610 Panel	Offsetting IHF	1.00	1.64	1.31
	Non-Offsetting	1.22	1.01	1.11
Overall Results	Offsetting IHF	1.15	1.34	2.31
	Non-Offsetting	1.29	1.00	2.53

IHF/SIS Implementation Recommendations and Workflow

Based on the collective research, a comprehensive workflow has been developed that integrates vertical well data acquisition, data processing, SIS/IHF well drilling and completion, treatment execution, diagnostics, and post-processing/modelling activities into a sequential framework for IHF implementation (Johnson Jr 2024). The workflow incorporates critical learnings from the initial Jaws 1ST application in the Cooper Basin (Johnson Jr., Cheong, et al. 2020), the Surat Basin modelling case (Johnson et al. 2021), the Bowen Basin vertical and horizontal well trials (Johnson et al. 2021, Johnson and Ramsay 2024), and recent deep coal stress profiling work in the Taroom Trough (Johnson Jr. and Saldungaray 2025). A parallel integrated technology framework for CBM/CMM pilot well planning, encompassing geoscience, well testing, production technology, and reservoir engineering disciplines, has been presented by Johnson Jr., Holl, and Tauchnitz (2025); the IHF/SIS workflow described herein aligns with and builds upon that broader framework. While many of the individual elements are not atypical of CBM well activities, the nuances associated with IHF — particularly stress characterisation across multiple lithologies, maintaining indirect fracture-to-wellbore connectivity, managing over-flushing risk, and the iterative exchange between fracture and reservoir models — distinguish this workflow from conventional completion and stimulation practices. The recommended sequence and key considerations at each stage are described below.

Vertical Pilot Well, Data Acquisition and Stress Characterisation

In compressive or transpressive basins — common across the Eastern Hemisphere — high tectonic strains cause significant difficulties when targeting fracture stimulations directly in the coal (Johnson Jr., Cheong, et al. 2020), with numerous authors documenting complex fracture geometries from direct coal initiation based on treatment mine-backs (Diamond, 1987; Diamond & Oyler, 1987; Jeffrey et al., 1992; Jeffrey & Settari, 1998; Jeffrey et al., 1995; Jeffrey et al., 1987; Jeffrey et al., 1998; Johnson et al., 2010; Palmer et al., 1993). In Australia's Cooper and Bowen Basins, the higher stress in the clastics compared to the bounding coal intervals (Hillis et al., 1999; Reynolds et al., 2006; Tavener et al., 2017) makes a strike-slip stress state ideal for IHF. Therefore, accurate stress characterisation is the critical first step in the workflow and the primary determinant of IHF feasibility.

Plan and drill a vertical pilot well at the intersection of the proposed IHF and SIS well azimuths, preferably at a down-dip location to maximise the potential to lower bottomhole pressure. Acquire dipole sonic and micro-resistivity image log data, DSTs in the target coal, and multiple DFITs across clastics of varying moduli to enable the simultaneous solution for tectonic strains using the Kirsch (1898), poroelastic (Thiercelin and Plumb 1994), and fissure opening pressure equations (Zoback 2007, Pokalai et al. 2016). The resulting fracture can be imaged on post-DFIT image logs, and DFIT data in the coal and interburden provide breakdown and closure pressures for a localised 1D stress profile. These strains cannot be resolved from a single coal initiation and are best obtained by solving simultaneously from multiple data points across strata of differing moduli (Johnson Jr. and Saldungaray 2025). Where direct

DFITs in coal are impractical due to extended closure times, injection/flowback inflection point testing can verify the predicted coal stress; recent work in the Taroom Trough demonstrated that inflection points in the Kianga Formation coals closely aligned with the stress profile predicted from DFITs in the underlying Back Creek Formation clastics, increasing confidence in treatment design for interbedded coal/sandstone sequences (Johnson Jr. and Saldungaray 2025). Knowing the stratigraphy and stability of the interburden is essential — underlying or overlying zones of instability or fluid sensitivity (e.g., highly lithic, shale, tuffaceous intervals) should be identified and avoided as they may affect long-term IHF well-to-fracture connectivity. Once testing is complete, the vertical well can be left as an open-hole completion through the coal and interburden with PVC or glass-reinforced epoxy (GRE) casing cemented through target intervals where additional formation stability is required (Johnson Jr 2024).

Data Processing and Model Building

Define PDP. Understanding PDP behaviour is essential for evaluating success with any hydraulic fracturing methodology for low-permeability coal reservoirs during early appraisal periods. Defining this PDP behaviour requires DFIT data, a capable reservoir simulator, and a good understanding of coal properties and key model parameters. The DFIT is a key tool in that: (1) DFITs investigate the permeability above fracture closure pressure (i.e., low net effective stress conditions) and derive a pressure-dependent leak-off (PDL) constant; (2) once the fracture has closed, the DFIT provides an estimate of Darcy leak-off and initial permeability that can be used to calibrate reservoir parameters using the Carter leak-off equation (Howard and Fast 1957); and (3) estimates of permeability losses to PDP under high net effective stress can be better estimated (Johnson Jr., You, et al. 2020). The workflow produced by Johnson Jr., You, et al. (2020) was multi-disciplined and tied all coal static and dynamic reservoir characterisation processes to better constrain the final history-matching to enable more accurate forecasting of post-fracturing future performance. The key enabler to better productivity and development planning decisions earlier in the appraisal process is the characterisation of fracture compressibility obtained from history-matching the DFIT after-closure data in a Pressure-Dependent capable Reservoir Simulator (PDRS). This was completed using multi-scenario evaluations to obtain a best-fit match (see Figure 11). Pre-determining these parameters earlier in a development plan can improve project economics (Johnson Jr 2024).

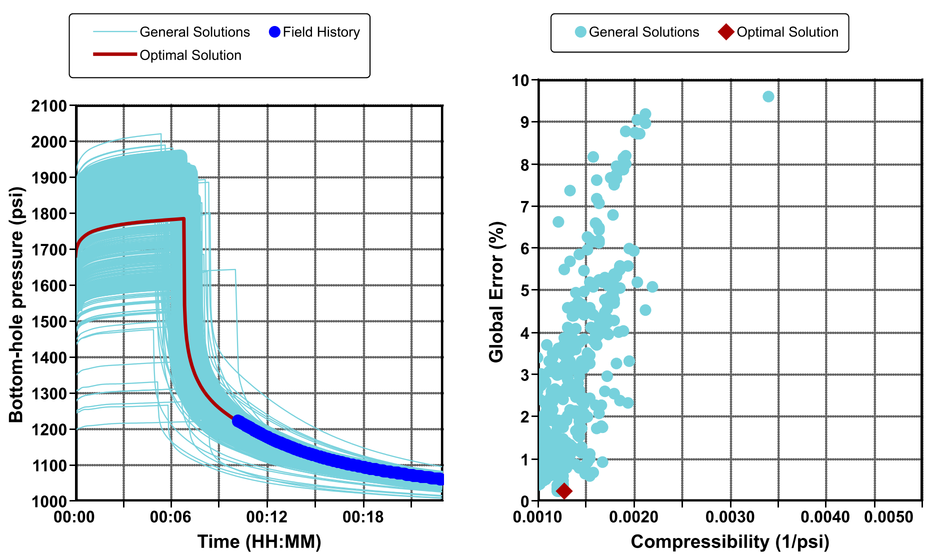

Figure 11. ACA of DFIT using PDRS (Analyst 3). Left: 'Best Fit' parameters (red trace) versus field observed data (blue markers). Right: Values of compressibility tested and their associated errors (After Johnson Jr., You, et al., 2020).

Hydraulic Fracture and Reservoir Models. Build the hydraulic fracture and reservoir models to design well azimuths, trajectories, treatment schedules, and anticipated SRV dimensions. Initial reservoir modelling may use average conductivity values to estimate the benefits of IHF/SIS co-application and optimal spacing (Ramanandraibe et al. 2023); a multilayer model is required where stacked sandstone, siltstone, carbonaceous shale, and coal sequences exist, and clastic intervals may contribute to production. The fracture model should be capable of discerning back stress as well as inter- and intra-layer effects along the planned trajectory, with sleeve placement optimised to minimise back stress effects — which are largely related to the IHF-hosted interval based on its higher modulus relative to the targeted coal (Johnson Jr 2024). Integrating a DFIT into multi-well interference testing offers a powerful method for characterising coal seam permeability and anisotropy; the DFIT-derived fracture can serve as the pulse source in a PDRS to analyse the pressure response in offset observation wells and inform optimal well spacing (Johnson Jr., Holl, and Tauchnitz 2025).

SIS and IHF Well Drilling and Completion Design. Drill SIS wells first to confirm seam continuity and structure, pre-positioned within the anticipated IHF fracture interconnection radius (60–120 m). Acquire LWD data, including azimuthal natural gamma ray and compressional sonic, to correlate coal material properties with the vertical well. Intersect the vertical well and suspend with a PVC or GRE liner to allow re-entry for cleanouts. For mining applications, pre-configure SIS wells with pressure monitoring prior to IHF treatment (Johnson and Ramsay 2024). Co-application in a pre-existing SIS field will result in frac hits, necessitating a post-frac workover and clean-up strategy for offsetting wells (Johnson et al. 2021).

Land the IHF well with packers and frac sleeves spaced at 40–50 m based on preliminary modelling and perform multiple toe DFITs to verify the stress model at the lateral level. The toe DFIT should confirm the PDL coefficient, fissure opening pressure, and closure stress. Drill toe-down to minimise valleys and intercept the vertical production well with adequate sump volume. Place the standoff ‘floor touches’ introduced earlier (see Introduction) within packer-isolated intervals, particularly where azimuthal GR is not available. Eliminate washouts and key seats that may affect packer performance; consider multi-element packers if hole callipers become problematic (Johnson et al. 2021).

Fracturing Treatment Execution and Diagnostics. Execute the hydraulic fracturing treatment with stage-by-stage diagnostic mini-fracs, step-down tests, and adequate shut-in time to provide additional permeability estimates and an evolving stress picture along the lateral. The fracture model should be updated as the treatment progresses, and monitoring of the SIS wells should ascertain frac hits versus time. Continuous (on-the-fly) ball-dropping systems are recommended to minimise over-flushing — the only documented cause of stage failure across all IHF stages placed to date. Fracture reorganisation post-injection is highly likely given the low post-frac leak-off, higher width from lower coal modulus, and continued extension post-shut-in; the balance between aggressively propping the fracture and avoiding a screen-out is more pronounced where large stress contrasts are present (Johnson Jr., Cheong, et al. 2020). Proppant selection, concentration, and placement strategy should adequately prop fractures intersecting the SIS wells while minimising embedment (Wang et al. 2021), reducing fines generation (Fraser and Johnson Jr 2018), and incorporating breaker technologies to minimise conductivity loss (Johnson Jr 2024).

No singular diagnostic methodology is adequate to fully describe the fracturing process in coals. A comprehensive program including surface deformation tiltmeters, strain measurements in offsetting SIS wells, liquid tracing of each stage, and micro seismic monitoring is recommended. Liquid tracers provide ground-truthing of production by stage and fracture connectivity; fixed-location, slow-release gas, and water-dissolving tracers can provide understanding of long-term production contributions by zone. Distributed acoustic sensing (DAS) monitoring using fibre-optic cable in offsetting vertical or lateral wells is an emerging method for understanding fracture geometry and frac hits, with strain processing like downhole tiltmeter measurements. Fibre-optic configured laterals may give greater confidence than micro seismic monitoring on fracture propagation, particularly in mining environments where depletion-related stress relaxation generates significant micro seismic noise (Johnson Jr 2024, Johnson and Ramsay 2024).

Update Post-Frac Models and Go-Forward Strategy. A fully calibrated post-job fracture model should be imported back into the reservoir simulator and used to history-match post-frac production. These steps are iterative, taking data from the fracturing model to the reservoir model and vice versa. Extend the calibrated understanding to evaluate adjacent panels, optimise stage count and spacing, and assess micro-proppant co-application against baseline treatments. More detailed anisotropy data from multi-well interference testing can be incorporated to run sensitivities and firm a development go-forward strategy. Consider the need for additional UIS drilling and solids-manageable artificial lift systems such as ESPCP, particularly in formations prone to coal fines or interburden production (Johnson Jr 2024, Johnson et al. 2021).

Reservoir-Scale Sensitivity Analyses of Key Variables

The effectiveness of IHF co-applied with SIS wells is governed by several interrelated reservoir, completion, and economic variables. The data acquired through the workflow described above — particularly the 1D stress profile, DFIT-derived PDP parameters, and calibrated fracture/reservoir models — directly informs the sensitivity of these variables. This section first summarises the key sensitivities observed across field applications, then presents the reservoir modelling framework developed to quantify these effects.

Key Sensitivities Observed Across Field Applications

However, this contrast is not static — the SG608-01 case in a pre-drained panel and the SG609-02 case in an undrained panel demonstrated markedly different treating pressure responses for the same seam, confirming the sensitivity of IHF performance to the local depletion-dependent stress state. At Moranbah North Mine, localised mining effects further modify the floor stress regime, creating a locally destressed zone below the seam, unlike profiles observed in undrained areas (Johnson et al. 2021, Johnson and Ramsay 2024). These observations underscore why the workflow requires multiple DFITs across varying lithologies and depletion states to calibrate the stress model before treatment design, and why toe DFITs in the IHF lateral are necessary to verify the stress profile at the point of execution.

Stress Contrast and Depletion State. The stress contrast between the coal and bounding clastics is the primary geomechanical control on IHF fracture behaviour. In strike-slip regimes, the coal is typically lower stressed than bounding intervals, facilitating fracture migration from the IHF wellbore into the coal.

IHF Well-to-Seam Separation. The proximity of the IHF wellbore to the target seam directly affects both fracture geometry and the risk of longitudinal components. In the SG609-02 case, the region of greatest separation between the IHF well and the seam corresponded to Day 3 (Stages 5–9), where the model predicted some longitudinal components in addition to transverse fractures — consistent with micro seismic events closely adjacent to the IHF wellbore. A sensitivity analysis on wellbore position in the Surat Basin modelling case determined the optimal location at the base of the lowermost coal ply to maximise seam coverage with IHF treatments (Johnson et al. 2021). Maintaining the lateral within 2–4 m of the seam with intermittent floor touches has proven effective in both the SG608-01 and SG609-02 applications (Johnson and Ramsay 2024).

Interlayer Effects and Long-Term Connectivity. The fluid sensitivity, formation stability, and modulus of the hosting clastic layer affect the long-term IHF well-to-fracture connectivity. Back stress effects from prior stages are related to the IHF-hosted interval based on its higher modulus relative to the targeted coal (Johnson Jr., 2024). In the Walloon Coal Measures, interbedded sandstone and siltstone intervals have been found prone to fluid degradation and plasticisation because of clay mineralogy, which may diminish long-term conductivity if not managed through appropriate fluid and proppant selection (Johnson et al. 2021). These interlayer effects reinforce the workflow requirement for thorough geological and petrophysical characterisation of the interburden prior to IHF well planning, as emphasised in the integrated technology framework for CBM/CMM pilot well planning (Johnson Jr., Holl, and Tauchnitz 2025).

Over-Flushing Risk. As the connection from the initiation to the larger fracture is an indirect connection, the risk of over-flushing during treatment placement remains the only documented cause of stage failure across all IHF stages placed to date. The single failure occurred in the Jaws 1ST well, where over-displacement caused disconnection between the indirect fracture and the horizontal wellbore. Conservative spacer volumes and a strict QC protocol with pre-frac mini-fracs for each stage are essential to calibrate leak-off and minimise over-displacement risk (Johnson Jr., Cheong, et al. 2020).

Micro-Proppant Opportunities to Improve SRV. Once PDL is properly identified, and the dilation of natural fractures and cleats can be identified through diagnostics, conventional-sized proppants within complex fracturing environments will leave fractures unpropped. Laboratory studies have shown that particles greater than 325 mesh (50 μm) do not penetrate and prop natural fractures in coals under laboratory leak-off conditions (Keshavarz et al. 2014, Johnson et al. 2022). Commercially available micro-proppants in the 10–50 μm range can reduce fracturing fluid loss to natural fractures and preserve stress-sensitive natural fracture conductivity (Johnson et al. 2022). The first field application of a commercially available ceramic micro-proppant in the Taroom Trough has demonstrated that sub-50 μm materials can be successfully deployed in coal stimulations, with anecdotal evidence of increased cleanup post-frac relative to previous deep coal stimulations at shallower depths (Johnson Jr. and Saldungaray 2025, Johnson Jr., Holl, and Tauchnitz 2025). Reservoirs exhibiting PDP behaviour are likely to be the key candidates for successful micro-proppant application, as conventional fracturing technologies in high PDL environments with fracture complexity have failed to deliver a stimulated reservoir volume adequate to achieve commercial gas flows (Johnson Jr 2024).

Reservoir Modelling of Key Sensitivities

To quantify the relative impact of the above variables on SRV expansion, Estimated Ultimate Recovery (EUR), and Net Present Value (NPV), a systematic reservoir modelling study was conducted using a PDRS calibrated to observed DFIT and production data (Ramanandraibe et al. 2023). The modelling framework, key assumptions, and reservoir-scale sensitivity results are summarised below; the detailed modelling methodology and co-application economics are presented in the following section.

Permeability. Coal permeability is the primary discriminator in gas recovery and well productivity. Reservoir modelling demonstrates that for permeability values below 1.0 mD, standalone SIS wells are uneconomic and do not provide adequate pre-drainage. The application of IHF in conjunction with SIS wells significantly improves gas production and EUR in low-permeability coals. More permeable coals exhibit a higher EUR, but the relative increase in gas production because of IHF stimulation is proportionally lower compared to low-permeability coals, as the base SIS performance is already higher (Ramanandraibe et al. 2023).

Permeability Anisotropy. The degree and direction of permeability anisotropy (k_y:k_x) significantly affects reservoir deliverability and optimal fracture placement. In many cases in the Walloon Coal Measures, the natural fracture direction (k_{Max}) can be acutely to orthogonally oriented to the hydraulic fracture orientation (Ramanandraibe et al. 2022). Higher anisotropy ratios require closer well spacing and more fracture stages to achieve equivalent drainage. DFIT-based multi-well interference testing, as described by Johnson Jr., Holl, and Tauchnitz (2025), provides a practical method for characterising directional permeability and informing optimal well spacing in the field.

Fracture Half-Length, Well Spacing, and Stage Count. Determining the optimum combination of fracture half-length, well spacing, and number of stages is key to optimised reservoir deliverability. Modelling indicates that greater than ten fracture stages are required to achieve profitability; thereafter, the SRV, EUR, and NPV increase with the number of fracture stages. The relationship is not linear: initial stages provide the greatest incremental benefit, with diminishing returns as stage count increases beyond approximately 20 stages for a given lateral length. The optimum fracture half-length ranges between 400–600 m, with corresponding SIS well spacing of 800–1200 m for CBM applications (Ramanandraibe et al. 2023). For CMM pre-drainage, well spacings are typically in the order of 50–60 m between parallel SIS wells, and the time required to achieve target gas contents may necessitate closer IHF stage spacing (Johnson Jr., Holl, and Tauchnitz 2025).

Micro-Proppant Benefit. Sensitivity modelling shows that as permeability increases, the incremental NPV from micro-proppants decreases due to marginal improvement in production relative to the additional cost. For the case of 20 fracture stages at 0.1 mD, the relative increase in discounted cash flow versus the cost of micro-proppants was approximately 79%. At 1 mD, the NPV without micro-proppants outweighs the case with micro-proppant injection due to the small improvement in production relative to the additional cost. Until further laboratory testing or actual field cases determine that greater improvement is possible, micro-proppants are best applied in low-permeability coals below approximately 1 mD (Ramanandraibe et al. 2023).

Modelling Next Steps for CBM and CMM Applications

The reservoir modelling framework developed by Ramanandraibe et al. (2023) provides the basis for quantifying the potential benefits of IHF/SIS co-application and micro-proppant integration. This section outlines the modelling methodology and key findings that inform go-forward strategies for both CBM and CMM applications.

Reservoir Modelling Framework. Single and multi-stage fractures were modelled using a PDRS to assess well stimulation effectiveness across a range of IHF stages (1, 2, 5, 10, 15, and 20 stages). The model was constructed as a 2D bi-wing fractured well consisting of Cartesian grids incorporating Local Grid Refinement (LGR) along the fracture faces to improve computational stability. The quarter-symmetry model integrated a high-permeability coal overlying a low-permeability sandstone hosting the IHF lateral (Ramanandraibe et al. 2023). Key reservoir parameters maintained from history-matched models included fracture porosity, average permeability, permeability anisotropy, and fracture compressibility. The Palmer and Mansoori (1998) model was used to represent permeability changes with pressure, incorporating matrix shrinkage effects. A modified Langmuir function was used to describe gas desorption behaviour (Ramanandraibe et al. 2023).

IHF/SIS Co-Application Results. The co-application of IHF and SIS wells was evaluated across varying permeability scenarios and well spacing configurations. Key findings include: (1) well spacing and fracture half-length affect the recovery of gas from coal reservoirs, with determining the optimum spacing between SIS and IHF wells key to optimised deliverability; (2) for permeability values below 1.0 mD, standalone SIS wells are uneconomic; (3) greater than ten fracture stages are required for profitability, with SRV, EUR, and NPV increasing with additional stages; and (4) optimising NPV requires a long-term view of production and drainage (Ramanandraibe et al. 2023).

Micro-Proppant Integration Modelling. The modelling framework was extended to evaluate the co-application of micro-proppants with IHF treatments. The micro-proppant benefit was represented as an increase in the effective SRV through maintaining natural fracture conductivity that would otherwise decline with increasing net effective stress during production. The modelling showed that the relative increase in gas production because of micro-proppant injection is most significant in low-permeability coals, where the base-case decline in natural fracture conductivity has the greatest impact on production (Ramanandraibe et al. 2023). For CMM applications, mines may require more rapid pre-drainage programmes to lower gas contents to safe levels and maintain mine productivity. For low-permeability cases, lower spacings of IHF and SIS wells and additional Underground-to-Inseam (UIS) drilling may be required to reduce gas contents within 2–3 years. The modelling results provide operators with a framework for economic evaluation, balancing drainage timing requirements against capital expenditure for different combinations of IHF stage count, SIS well spacing, and micro-proppant inclusion.

The collective learnings from the cases documented herein — from the Jaws 1ST over-flushing failure and tracer-confirmed interconnections, through the mine-back validated vertical well trials, to the stage-by-stage pressure evolution observed across SG608-01 and SG609-02, and most recently the stress profiling methodology developed for deep interbedded coal/sandstone sequences — have been distilled into the workflow presented in Figure 12. Key elements highlighted in red denote steps that are either unique to IHF implementation or that materially improve subsequent processes, particularly those related to stress characterisation, fracture-to-wellbore connectivity, and post-frac evaluation (Johnson Jr 2024).

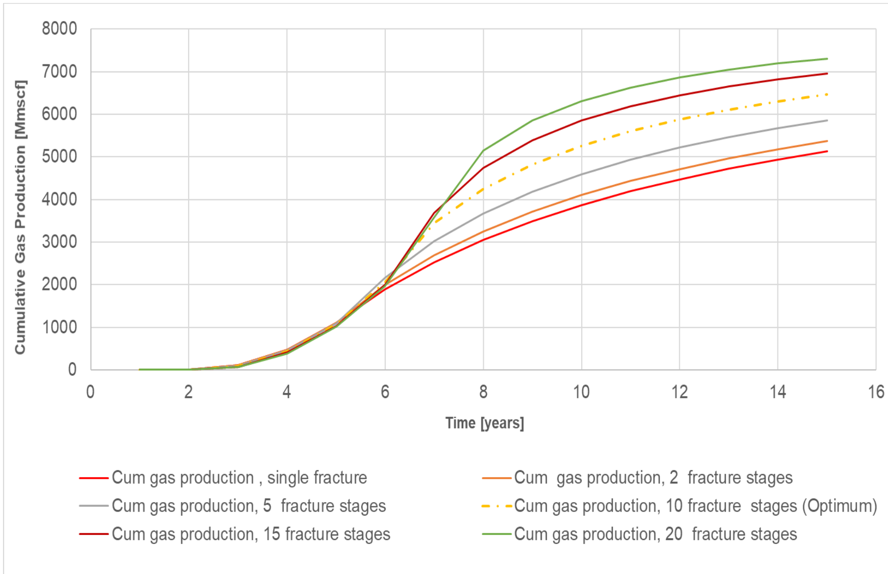

Figure 13. Comparison of EUR for SIS-only versus IHF/SIS co-application across varying permeability scenarios (after Ramanandraibe et al. 2023).

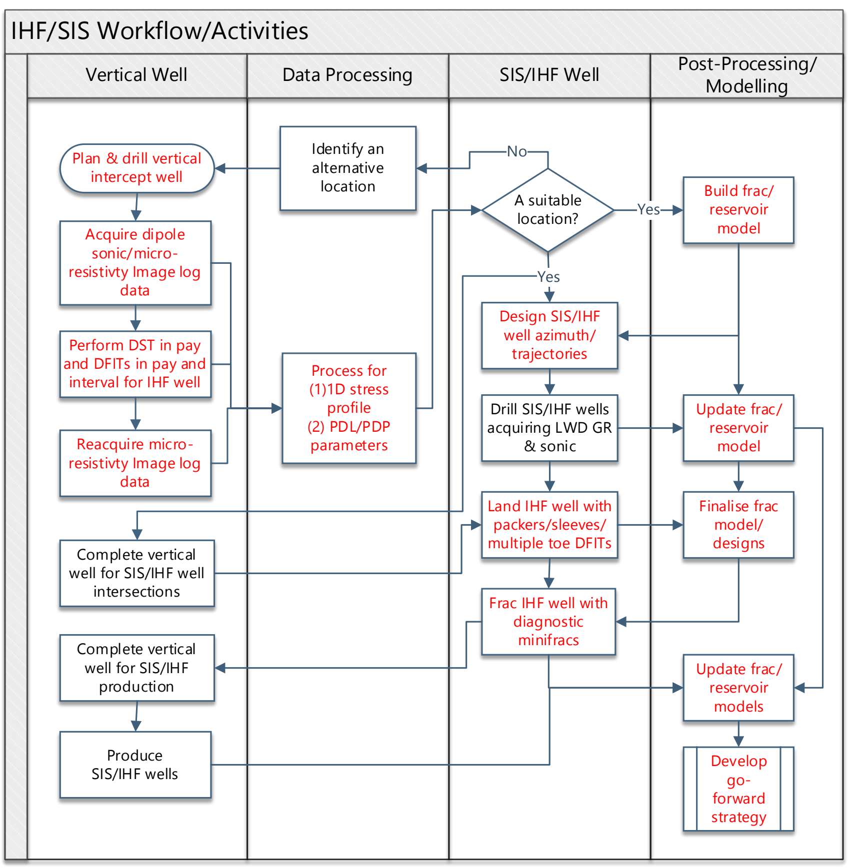

Figure 12. IHF/SIS workflow with key elements highlighted in red. (after Johnson Jr, 2024)

Small-Scale Hydraulic Fracture Modelling Sensitivity Study

To complement the reservoir-scale sensitivity analysis, a parametric hydraulic fracture modelling study was conducted using the calibrated and history-matched stress profile and hydraulic fracturing model from the first IHF application at the S0774 well in the Goonyella Middle Seam, Moranbah North Mine (Johnson et al. 2021). Whereas the reservoir-scale modelling (Ramanandraibe et al. 2023) quantified the impact of permeability, stage count, and spacing on EUR and NPV at the drainage scale, this study examined the near-wellbore fracture propagation mechanics governing whether an IHF fracture successfully enters the coal and impacts on hydraulic fracture length, a prerequisite for any of those reservoir-scale benefits to be realised.

Methodology

The three-dimensional planar hydraulic fracturing simulator (Barree 1983) was used to simulate fracture initiation in the interburden clastic floor and propagation into the overlying coal. The calibrated 1D stress profile and history-matched treatment data from S0774 (Johnson et al. 2021) provided the base-case geomechanical framework. Design scenarios systematically varied coal permeability (0.1, 1, and 10 mD), clastic floor permeability (0.01–0.1 mD), and perforation standoff distance from the coal floor (2–6 m) under the field-observed stress scenario (pressure gradients of 0.373 psi/ft in coal, 0.380 psi/ft in the clastic floor). Fluid and proppant staging were held constant across all scenarios to isolate the effects of these three parameters on fracture geometry, net pressure, and propped dimensions. Fracture dimensions were evaluated using a minimum proppant cutoff of >0.5 lb/ft² and an equivalence of >5 mDft conductivity, consistent with the criteria applied in the field case modelling.

Observations

The results demonstrate that standoff distance is the dominant control on whether the IHF fracture enters the coal and the relative fracture heights in the coal and floor intervals (Figures 14 and 15). At 2 m standoff, all permeability cases achieve significant propped fracture lengths in the coal, with the 10 mD case yielding the greatest length (~380 m), followed by 0.1 mD (~280 m) and 1 mD (~220 m). Propped fracture heights at this standoff range from 3.8 to 5.5 m, approaching the full GM seam thickness in all cases. The corresponding floor propped lengths are minimal (~0–40 m), confirming that the fracture energy is directed into the coal when the wellbore is proximate to the seam. Higher coal permeability values reduce net pressure and therefore PDL. A previous study that showed increased PDL decreases overall fracture length but increases lateral leak off as compared to Darcy-controlled leak off; increased lateral invasion provides a greater potential area for SRV enhancement by micro-proppant implementation than is afforded to Darcy-controlled leak off invasion (Ramanandraibe et al., 2022)

At 3 m standoff, the permeability ranking changes. The 10 mD case drops sharply to ~20 m propped length in coal, while the 0.1 mD (~210 m) and 1 mD (~200 m) cases maintain substantial coal entry with propped heights of approximately 5 m. This inversion reflects a reduction in net pressure by increased leak-off in the 10 mD cases, restricting upward penetration. Reduced leak-off in low-permeability coal preserves higher net pressure and fracture width, facilitating further upward growth. The floor propped lengths at 3 m standoff increase (200–550 m), indicating that a proportion of the fracture energy is being partitioned into the floor even while coal fracture extension is being maintained.

Beyond 3 m standoff, a sharp transition occurs. At 4 m and greater, propped fracture lengths and heights in the coal collapse to near-zero for all permeability cases (see Figure 14).

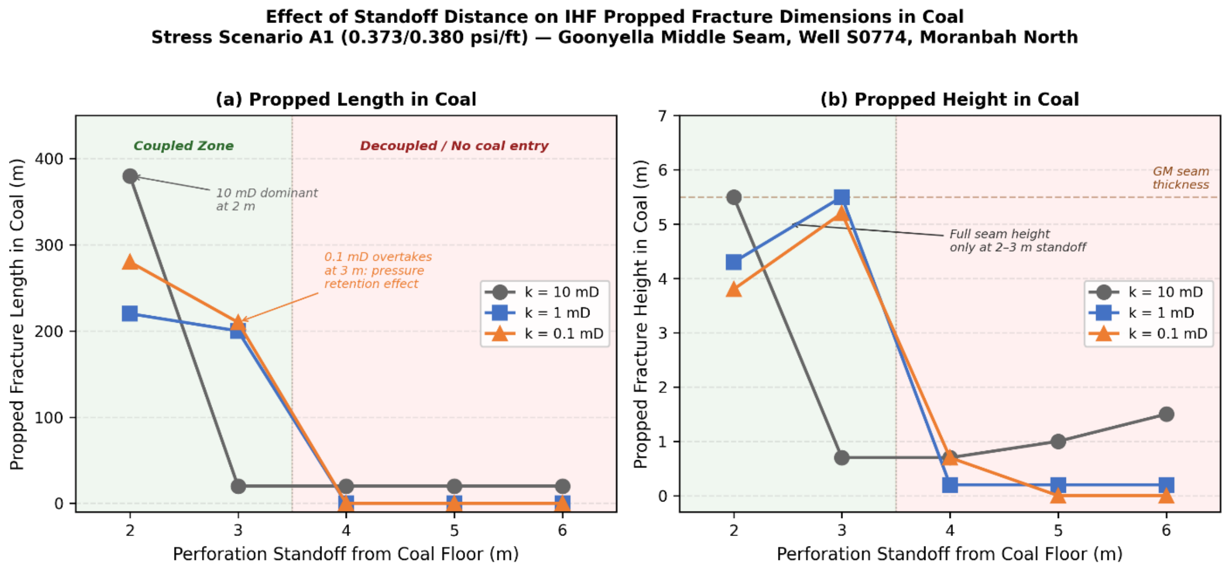

Figure 14. Effect of standoff distance on IHF propped fracture dimensions in coal: (a) propped fracture length and (b) propped fracture height. Stress Scenario A1 (0.373/0.380 psi/ft coal/floor gradients), Goonyella Middle Seam, Well S0774, Moranbah North.

The fractures are fully contained within the clastic floor, where propped lengths increase progressively with standoff distance, reaching 500–680 m at 6 m standoff. Within this contained regime, floor fracture length scales with clastic permeability, reflecting permeability-controlled leak-off stabilised propagation. Floor propped heights grow from ~2 m at 2 m standoff to 6.5–7.5 m at 6 m standoff as the fracture propagates vertically within the floor rather than crossing the coal–clastic interface (see Figure 15). If dual laterals were drilled with the lower closer to the underlying GM Lower Seam, then effective downward growth could create IHF fractures into that interval, increasing overall drainage in a pattern system of IHF and SIS wells in multiple seams.

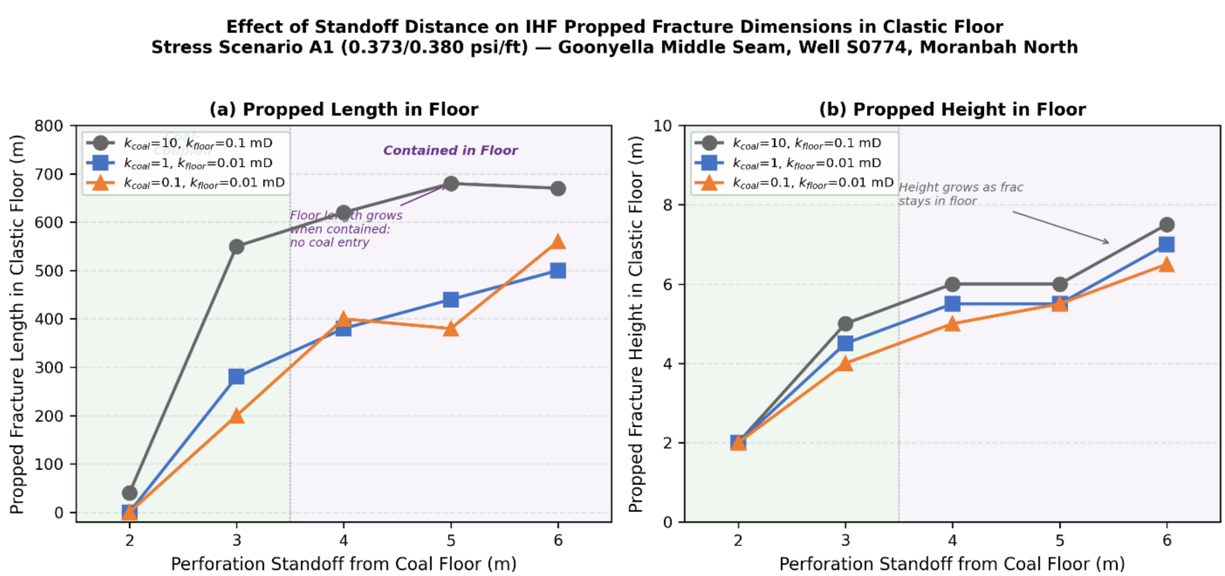

Figure 15. Effect of standoff distance on IHF propped fracture dimensions in the clastic floor: (a) propped fracture length and (b) propped fracture height.

Results

These modelling results identify a critical coupled-to-contained threshold at 3–4 m standoff. Below this threshold, the fracture is hydraulically coupled to the coal and propagates into it; above it, the vertical stress contrast and limited net-pressure gradient across the interface prevent upward migration regardless of permeability. This provides the quantitative basis for the field-established 2–4 m wellbore-to-seam separation recommended in the previously outlined workflow (Johnson Jr, 2024).

The permeability inversion observed at 3 m standoff — whereby low-permeability coals (0.1 and 1 mD) achieve longer propped fractures in the coal than the 10 mD case — is a significant finding. It indicates that IHF is proportionally more effective in the low-permeability coals where it is most needed, as reduced leak-off preserves the net pressure required for fracture propagation across the coal–clastic interface. This result is fundamentally encouraging for Bowen Basin CMM applications, where the primary IHF targets are seams below 1 mD.

Potential Improvements and Future Applications

Based on the field experience and modelling results presented previously, several potential applications and improvements are identified: (1) better drainage in areas where direct placement of SIS wells is difficult or unstable; (2) overlying implementation where seam floors are unstable or if tuffaceous siltstones are present; (3) stimulation of floor or rider seams to improve drainage and reduce goaf influx post-mining; (4) co-application of micro-proppants to extend the effective SRV based on laboratory and modelling studies indicating three-fold improvements are likely on an individual fracture basis (Keshavarz et al. 2014); (5) optimisation of SIS/IHF well placements to more rapidly drain low-permeability areas by increasing hydraulic fracture interconnection through simultaneous treatments akin to the zipper-frac process used in North American shale gas treatments (Johnson and Ramsay 2024).

Conclusions

This paper has unified the key findings from five studies spanning a decade of Australian IHF research, field application, and mine-back verification in two basins into a cohesive framework for implementation in low-permeability CBM and CMM applications. The following conclusions are drawn:

IHF is a proven technology for low-permeability coal stimulation in compressive and transpressive stress regimes. Fifty-five (55) stages have been placed across five wells (two vertical, three horizontal) in the two basins with consistently low Near-Wellbore Pressure Loss (NWBPL) and negligible screen-out risk. The only known stage failure was attributed to over-flushing. IHF co-applied with SIS wells can improve gas production and EUR in low-permeability coals (below 1 mD) in predrainage scenarios, where standalone SIS wells are uneconomic. Greater than ten fracture stages are required for profitability, with diminishing returns beyond approximately 20 stages (Ramanandraibe et al., 2023). Normalised UIS and SIS production data do not indicate any impairment to productivity by IHF/SIS interaction and show localised improvement in undepleted areas and anecdotal evidence of improvements in areas to be redeveloped by UIS drainage post-fracturing.

DFIT-calibrated modelling using a PDRS provides the essential framework for characterising PDP behaviour from PDL and after closure analyses, constraining fracture compressibility, and generating reliable baseline production forecasts. Pre-determining these parameters earlier in a development plan improves project economics and forecasts the potential benefit of micro-proppant application.

Micro-proppant co-application with IHF provides the greatest incremental benefit in low-permeability coals by maintaining natural fracture conductivity under increasing net effective stress. As noted by Ramanandraibe et al. (2022), the SRV created by PDL in lower-permeability coals can enhance the productivity. The first field deployment of commercially available micro-proppants has been completed

(Johnson Jr. and Saldungaray 2025), and early results have exceeded all treatments in the Cooper Basin and deepest CBM gas in Australia.

Reservoir scale sensitivity analyses identify permeability, fracture half-length, stage count, and stress contrast as the dominant variables affecting IHF performance. Over-flushing risk and interlayer effects require careful management through strict QC protocols and geological characterisation.

Small-scale sensitivity modelling results identify a critical coupled-to-contained threshold at 3–4 m standoff. Below this threshold, the fracture is hydraulically coupled to the coal and propagates into it; above it, the vertical stress contrast and limited net-pressure gradient across the interface prevent upward migration regardless of permeability. This provides the quantitative basis for the field-established 2–4 m wellbore-to-seam successfully implemented in the 3 lateral applications.

For CMM applications, IHF addresses the critical challenge of pre-draining low-permeability panels in advance of mining using non-steel completions below the seam. Mine-back evaluations confirm the structural stability of the IHF fracture zone (i.e., roof and floor decoupling) and alignment with the maximum horizontal stress direction.

Finally, returning to the title of this paper, not all parent–child well interactions have negative consequences. In the CMM co-application setting, the IHF lateral is deployed as the child well into a pre-existing pattern of predrilled SIS parent wells. Unlike the depleted-zone 'frac hits' and asymmetric fracture growth that typify adverse parent–child interactions in unconventional shale developments, the field evidence assembled in this paper — multi-well tracer recoveries at offsetting wells (Johnson Jr., Cheong, et al. 2020), pressure, fluid and proppant responses in adjoining SIS wells during IHF stimulation (Johnson et al. 2021; Johnson and Ramsay 2024), mine-back verification of contained, structurally stable fracture zones, and normalised UIS and SIS production data showing no impairment and localised improvement in undepleted areas (Ramanandraibe et al. 2023) — consistently demonstrates that the IHF child enhances, rather than degrades, the productivity of its SIS parents. The IHF child establishes a more effective shared SRV that encompasses the IHF and adjoining SIS wells (Johnson and Ramsay 2024), and that shared SRV is also available to later offsetting SIS and UIS wells drilled into the same panel post-fracturing. Properly designed and placed, the IHF–SIS parent–child relationship is therefore a beneficial one, accelerating just-in-time pre-drainage in low-permeability coals where standalone SIS parents are otherwise uneconomic.

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