AAPG Datapages/Search and Discovery Article #90234 © 2015 AAPG Asia Pacific Region, Geoscience Technology Workshop, Opportunities and Advancements in Coal Bed Methane in the Asia Pacific, February 12-13, 2015, Brisbane Australia

Is it the Geological Environment, Engineering Skill or Luck that Differentiates the Success of Hydraulic Fracturing in Australian Coal Seam Gas Projects?

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Abstract

Coal seam gas (CSG) pilot testing is employed to characterize the production from a particular geo-domain associated with certain perceived geological risk and uncertainty or to estimate potential project reserves to a reasonable degree of accuracy for further development planning. These pilots strive to increase the chance of success by defining optimal reservoir characterisation methods and developing the most effective stimulation strategy (e.g., cavitation, hydraulic fracturing). CSG pilots often attribute success to a combination of several factors, including favourable:

- geologic, structural or geomechanical settings;
- reservoir properties such as the permeability distribution or gas content; and
- completion or stimulation strategy, most often hydraulic fracturing.

In Australia, this need to reduce uncertainty appears to be more pronounced based on the increased costs of development, tenure retention requirements, and technical risks that often remain an ongoing contingency for developmental decisions (Johnson and Mazumder, IPTC 18108, 2014). The largest technical contingency across several large basins in Australia continues to be the inability to produce economic outcomes using completions involving hydraulic fracturing. Thus, it is reasonable to believe that differences exist in the Australian and North American environments hindering widespread application of hydraulic fracturing.

In this presentation, key observations regarding several Australian CBM pilots will be presented and discussed. For each of these areas, the author will explore the questions of whether the geological/geomechanical environment, engineering skill or luck was the likely main contributor to success of hydraulic fracturing treatments in each area. Finally, the presentation will note areas for new technology implementation and experimentation to improve hydraulic fracturing success in problematic areas where high in-situ stress magnitudes or unfavourable current stress orientations exist relative to pre-existing cleats and natural fractures (formed by paleostresses).

Case Area 1, Permian Coal Measures: Bowen Basin (Moranbah/Middlemount, Dawson Valley/Moura and Scotia/Peat Fields)

The first area of discussion is the northern Bowen Basin area, which has been recognised as a world-class thermal and coking coal producing area with high coalbed methane (CBM or CSG) resources and the site of the earliest trials of hydraulic fracturing in the Australian CSG industry. Gas pre-drainage for mining operations is extensive across the mining areas of the basin, so areas surrounding current mines were logical areas to develop CSG resources based on North American experiences. After these early, unsuccessful, well-documented attempts

(Broadmeadow Field, Reeves O'Neill, ICBMS 19, 1989; Central Colliery, Jeffrey et al., SPE 24362, 1992; Dawson Valley, Morales and Davidson, SPE 25862, 1993), a hiatus in CSG development occurred in the northern areas until the recent Arrow Moranbah Gas Project.

The next unsuccessful Bowen Basin pilot attempts were made by Conoco in the Moura/Dawson Valley area using hydraulic fracturing techniques adapted from those used in the San Juan Basin (e.g., ~70% vol/vol nitrogen foamed, gelled water, fracturing fluids). Later, Oil Company of Australia (OCA now Origin) became successful at applying these strategies in its Moura area operations. As target coals were gas saturated and produced little associated water, foam treatments allowed rapid stimulation, completion and testing; however, 'water fractures' were eventually adopted as they allowed multiple stages to be performed more efficiently, using fracture ball/baffle combinations, and at reduced costs relative to nitrogen foamed fluids.

The next successful area for review is the Peat (Origin)/Scotia (Santos) Fields, encompassing a large structural, anticlinal complex formed along the Burunga-Leichardt Fault, a regional geological feature in the eastern Bowen Basin, and close to the township of Wandoan Queensland. The target of the Peat/Scotia Fields are the Upper Baralaba Coal Measures (UBCM), which are low ash, gas saturated coals, which are extensively fractured both in the direction of paleostresses (cleating) and with favourable natural fracture overprints based on modern stress azimuths. Whist the number of seams are lower than the Dawson Valley area, seams are thicker and have higher permeability values (e.g., 3-10 times higher). Early appraisal wells in the Peat and Scotia Fields both trialed hydraulic fracturing and cavity completions. Initial rates from the cavitation completions were high, but operational and production difficulties led to vertical completions with hydraulic fracturing going forward.

Early in both fields development, Origin and Santos used vertical wells with foam fracturing to allow rapid stimulation, post-fracture clean-up, testing, and connection; however, both fields evolved to using large-volume, low-sand concentration 'water fractures' in later developmental drilling programmes. Both operators observed areas of increased in-situ stress magnitudes and pressure dependent leakoff, affecting placement of hydraulic fractures in this high permeability environment (Badri et al., SPE 64493, 2000; Johnson, Flottman and Campagna, SPE 77824, 2003). Finally, both fields experienced wellbore failures related to shear events, theorised to be unresolved stress concentrations at layer boundaries or sub-seismic fault reactivations.

Overall Bowen Basin stress regimes are regionally compressional with strike-slip to transpressional enclaves based on prior studies (Hillis, Enever and Reynolds, AJES 5:46, 1999; Gillam, PhD Thesis, University of Adelaide, 2004). High magnitude stresses correlating to reduced permeability/productivity and reduced hydraulic fracture effectiveness had been noted in the Burunga Anticline fracture treatments (Johnson, Flottman and Campagna, SPE 77824, 2003). Further, a review of Dawson Valley well completions (McMillan and Palanyk, SPE , 2007) concluded from production data analyses that all seams were not being effectively stimulated and generalised that the stress regime may be a contributor to frac and production success or failure in that area. This evidence all points to in situ stress as a major determinant of permeability and pilot success in the Bowen Basin.

Walloon Coal Measures, Surat Basin

The next area for discussion is the Jurassic, Walloon Coal Measures (WCM) of the Surat Basin. Earliest hydraulic fracturing treatments (early-2000s) were trialed in the Roma Shelf, Undulla Nose, and Goondiwindi Slope WCM areas. All were largely ineffective with wellbore failures being observed in the Undulla Nose areas for both Queensland Gas Company Ltd (QGC) and Origin Energy (formerly OCA). The poor results from these fracture treatments led to the widespread acceptance of an alternative open hole, pre-perforated liner completion for the Walloons devised by QGC in mid-2004 (Johnson, Scott and Herrington, SPE 101109, 2006).

Further attempts have been made to develop lower permeability areas using ‘water fractures’, cross linked gelled water, and hybrid fracture treatments (i.e., large initial water volumes followed by cross linked gelled water) using various combinations of 100 mesh, 40/70, 20/40, and 16/30 mesh sands. These treatments have been largely unsuccessful at producing wells that will consistently reach economic thresholds at current domestic gas pricing. The stress regime is complex within the Walloons and changes over the large interval; treatments have largely provided little stimulation beyond that of affecting the near wellbore, naturally fractured environment. Thus, further advancement in hydraulic fracturing technologies and improvements in gas pricing (i.e., LNG pricing) will be required to progress some areas to be economic after stimulation in the Walloon coal measures.

Conclusions and Recommendations

In the Bowen Basin Permian coals, a generalisation could be made that initial fracture treatment successes in structured areas were largely insensitive to fracture size, fluid type or sand volumes and more likely attributable to favourable permeability and effective stress regimes associated with those structures. Certainly in the case of closely stacked pays, the results can be positively influenced by achieving better fracture distribution, as noted by the author’s own experiences and as reported by others. Further, in highly permeable, structured areas, fracture treatments still demonstrate high treating pressures and elevated levels of pressure dependent leakoff despite high permeability making operational placement of fracture jobs challenging. Finally, the Scotia/Peat field was the first area to clearly illustrate the stark effects that being on and off structure have had on the economics of Bowen Basin field developments; this inability to expand beyond the ‘stimulation envelope’ has also been observed in several directions off other structured areas.

In the Surat Basin Walloon coals, several significant and well documented hydraulic fracturing studies using extensive diagnostics have been made in low permeable areas by both the QCLNG and APLNG joint ventures (Johnson, et al., SPE 133063, SPE 133066, 2010; Scott et al., SPE 133059; 2010; Brooke-Barnett, et al., SPE 167064; 2013). Both projects determined from extensive analyses of the data generated by these well instrumented experiments that:

- overall high levels of horizontal stresses are prevalent with pressure dependent leakoff, poor fracture containment, and a unidirectional permeability system relating to natural fracturing that is neither favourably or unfavourably aligned to the current maximum stress azimuth;
- the stress regime moves from strike-slip to reverse as you moved upwardly within the thick (c. 300m), low net to gross (c. 10%), sequence of fluvial sands and coals;
- increased complexity of the hydraulic fracture was largely correlatable with lower stress magnitude differentials; and

- the propensity exists to directly enhance and extend the natural fractures in areas of lower horizontal stress magnitude differentials or low viscosity fluids, even at high rates.

New technologies are emerging that could improve success in both basins. QGC recently trialed drilling at 27.5 and at 60 degree inclination in the $\sigma_{H\text{-}Max}$ direction improved hydraulic fracturing in a known problem area (Megorden, Jiang and Bentley, SPE 167053, 2013); they observed improved containment in the targeted seams and improved fracture length in the $\sigma_{H\text{-}Max}$ direction. Prior studies noted that fractures at lowered injection rates with cross-linked fluids simplified dimensions in the $\sigma_{H\text{-}Max}$ direction. Finally, propping a larger stimulated reservoir volume of narrow aperture, stress-sensitive, natural fractures may be achievable using novel fluid and particle combinations derived by experimental results and modelling of selectively sized ultra-fine particles injected into coal cleats using specifically charged fluids (Keshavarz et al., SPE 167757, 2014; Keshavarz et al., APPEA Journal, 2014). Thus, sizable resources in higher stressed, lower permeability Australian CSG areas may be unlocked by the combination of:

- drilling inclined wells in the $\sigma_{H\text{-}Max}$ direction to ‘steer’ the fracture properly;
- pumping successive injections of specifically charged fluids containing properly sized ultra-fine particles to initially stimulate small fractures and cleats; and
- pumping larger hybrid fracture fluid treatments involving fine-meshed, sized particle, slick water injections followed by cross-linked gelled water with larger sized proppant.

In summary, the author believes experience and quick reaction are more important than design skills in effectively stimulating high permeability areas of the Bowen Basin. Improved designs incorporating new technologies are required to effectively stimulate and increase recovery from off structure wells with lowered permeability coals in both basins. New technologies can enable better fracture placement, create a more effective stimulated reservoir volume, and enhance production management by minimising stress-sensitive, permeability effects. The best areas for trialing these technologies the areas in both basins encircling most developed fields– the beginning of the problematic zone or ‘fracture envelope’, the best opportunity for success.