3.0 WELL TESTING AND STIMULATION

The five well tests (Stage 1-5) performed on the Shenandoah-1A were designed by a combination of APEX Petroleum Engineering and Falcon Oil and Gas personnel. Stages 1, 2 & 5 included a hydraulic fracture stimulation. APEX Petroleum Engineering also directed and monitored the stimulation and well test operations. Appendix VII contains design, acquisition and analysis data assembled by APEX for each hydraulic fracture stimulation (Stage 1, 2 &5).

The cementing, stimulations, coil tubing, nitrogen and other well site operations were performed on the Shenandoah-1A by Halliburton Energy Services (HES). The reports and documents for the various tasks that HES provided are contained in Appendix VIII included with this report.

Crocker Tucker Energy Services (CTES) provided the wireline bond logs, perforations, setting bridge plugs and other services on the Shenandoah-1A well. Appendix IX contains the reports that CTES provided.

Well testing on The Shenandoah-1A was provided by SGS Australia Pty Ltd. The well test pressures and fluid production plots are included in Appendix X. Appendix X.a contains the SGS Daily Reports.

The following is a summary of the five well test performed on the Shenandoah-1A.

3.1 Stage 1: Middle Velkerri Lower B

The Stage 1 completion and testing was performed over the Middle Velkerri Lower B interval 2529-2548 meters, Measured Depth from Rotary Table (MDRT). At the Shenandoah-1A location the Middle Velkerri Lower B section is interpreted to be a shale/siltstone source rock with average Total Organic Carbon (TOC) ~ 2 wt%. Mudlog gas shows are high over the Middle Velkerri Lower B (Figure 3.1.5.A).

3.1.1 Fracture Treatment:

On 14 October, 2011, Halliburton Energy Services pumped the stage 1 acid treatment and performed a diagnostic rate step-down test into the Middle Velkerri Lower "B" formation. The treatment consisted of 212 bbls of slick water and 36 bbls of 15% HCl. Lack of sufficient daylight precluded the completion of the fracture treatment which was performed the next morning. On 15 October, 2011, Halliburton Energy Services pumped the stage 1 fracture treatment which consisted of 6,406 bbls of slickwater placing 52,912 lbs of 100 mesh and 148,815 lbs of 40/70 mesh silica sand. The treatment was pumped down 2,548m of 4-1/2" P -110 15.1# Casing at an average rate of 41.2 bpm with an average pressure of 7,421 psi and a maximum sand concentration of 2.0 ppg. Initial well head pressure was 3,942 psi. The final bottom hole ISIP was 8,696 psi (1.044 psi/ft). Total fluid load is 6,654 barrels or 6,772 barrels including the wellbore volume. The treatment ended on 15 October, 2011 at 11:43 hrs.

Net pressure history matching suggests moderately complex fracture geometries with propped fracture half-lengths of approximately 54 m and cumulative sand concentrations of ~ 0.75 lb/sqft. The sand type and sand concentration should be of sufficient mechanical strength for a short term production test; however, higher quality man made proppant should be considered for long term production in a development program.
A definitive fracture closure pressure was not observed during the DFIT prior to the fracture treatment; however, the pressure character suggested the transient was in the process of changing and fracture closure pressure was assumed to be 0.8 psi/ft. Incorporating this value into the Hubert and Willis equation, which relates fracture closure pressure to pore pressure, suggests the reservoir pressure is on the order of 0.662 psi/ft to 0.567 psi/ft.

\[
P_{fc} = \frac{\gamma}{(1-\gamma)}(1-P_i)+P_i+T
\]

Where:

- \( P_{fc} \) = Fracture closure pressure (0.8 psi/ft)
- \( \gamma \) = Poisson’s ratio (assumed 0.29 to 0.35)
- \( P_i \) = Reservoir pressure (calculated to be 0.662 psi/ft to 0.567 psi/ft)
- \( T \) = Tectonic effects (assumed to be 0 in this area)

The average permeability modeled during the stage 1 fracture treatment was very low (0.000074 md).

### 3.1.2 Flow Back Summary:

The well was opened on 15 October, 2011 at 21:52 on a 12/64” choke with well head pressure of 4,632 psi. The choke size was reduced quickly to a 4/64” for the first several hours. The flow testing equipment proved very early on that it was not properly suited for unconventional well testing. It could not properly handle the high water rates in conjunction with the low gas rates; thus, steady gas rates were not easy to achieve. By 10:52 the morning of the 16th there was enough gas to burn the flare without the pilot being on. The specific gravity of the gas ranged from 0.626 to 0.704 probably due to increasing CO₂ content which ranged from 3% to 6% during that time. In addition to the gas being produced, condensate with an API gravity of 43 was collecting on the mud pit. 2. A. Additional analysis of the condensate fluid is documented in Appendix X included with this report.
By 12:52 on the 17th, the pressure had dropped to less than 100 psi and N₂ was started in order to help unload the water in the casing. The N₂ did help unload the casing and recover some burnable gas; however, the gas was not measureable so an attempt was made to decouple the N₂ from the gas with mass balance. With a total measured gas volume through the separator and a known N₂ volume, a gas rate of about 34 Mscfpd was derived. With the N₂ off, the well continued to support a lazy flare (Figure 3.1.2.B) which did not require the pilot to remain ignited. The casing remained loaded during this exercise so the gas rate, if the well was cleaned up and was not experiencing any loading effects, should have been higher. On 18 October, 2011, at 7:22, the test was terminated since the gas rate was insufficient to measure with the available equipment. The flow back separator has since been modified to better handle these specific flowing conditions.

Water recovery has been good with over 37% of the load. This was somewhat unexpected as load recovery in shale is usually lower than tight sandstones, ranging from 10% to a maximum of 40%. The fluid has a tendency to redistribute in the reservoir replacing the water converted during hydrocarbon
generation. However, most treatments in unconventional shale source rock are shut in for longer periods of time (weeks) at higher temperatures which gives the fluids longer to redistribute into the microstructure of the formation. The quick turnaround of this stage probably influenced the higher fluid load recovery.

There is no indication that formation water was being produced and none was expected. The increase in chlorides measured, in the flow back stream, was believed to be associated with leaching of minerals from the formation and is normal in unconventional plays. In addition, the dye added at the Halliburton blender and present in the fracture treatment fluid was also present in the well head fluid samples.

### 3.1.3 Reservoir Permeability:

The modeling of the DFIT data and fracture treatment results indicated a very low permeability over the Middle Velkerri Lower B interval. The average permeability over the rock contacted by the DFIT and stimulation was ~0.000074 md (74 nd). This is very low permeability and may require long lateral well bores to contact sufficient permeable formation to produce at acceptable rates.

The log derived permeability form the core based model develop prior to the Middle Velkerri Lower B test had an average ~ 0.006 md for rock greater than 4% porosity (PHIE>0.04). The only Velkerri core that is available for the center of the Beetaloo Basin is from the Shenandoah-1A, Core 2 (2511-2518 m). Core 2 is 12 m above the Middle Velkerri Lower B “sweet spot” (2539-2557 m). This model was edited to incorporate the results from the Stage 1 DFIT and fracture stimulation. The updated log derived average permeability for the Middle Velkerri Lower B using a cutoff of PHIE > 0.04 is ~ 0.000260 md (260 nd), net pay = 38.5 m. Therefore the deliverability (K*H) of the Middle Velkerri Lower B is estimated at 0.01 md meters.

### 3.1.4 Reservoir Gas Saturation:

The log model for gas saturation is represented graphically by a Pickett Plot (Figure 3.1.4.A). This plot is interpreted to be a very strong indication that the intergranular porosity over the Middle Velkerri Lower B is gas saturated. Gas storage is interpreted to exist in rock with porosity greater than ~ 4%. There is 38.5 m with intergranular porosity greater than 4%, average PHIE= 0.055, TOC =0.02, SW = 0.31 and Avg. Permeability = 260 nd (0.000260 md).
Figure 3.1.4.A Stage 1: Middle Velkerri Lower B - log derived Pickett Plot
3.1.5 Composite Petrophysical Interpretation (CPI) Plot:

Figure 3.1.5.A Stage 1: Middle Velkerri Lower B - CPI plot with updated permeability model
3.2  Stage 2: Middle Velkerri B Sandstone

The Stage 2 completion and testing was performed over the Middle Velkerri “B” interval 2481-2598.5 meters, measured depth. At the Shenandoah-1A location the Middle Velkerri B section is interpreted to be low porosity sands with shale laminations. Since there is little to no organic carbon identified over this interval, the Middle Velkerri B is not considered a source for hydrocarbons and therefore the hydrocarbons that are stored in the sands most likely migrated into the sand bodies from the Middle Velkerri LB source rock. Mudlog gas shows are high over the Middle Velkerri B (Figure 3.2.7.A).

3.2.1 Fracture Treatment:

On 19 October, 2011, Halliburton Energy Services pumped the stage 2 fracture treatment into the Middle Velkerri "B" formation. The treatment consisted of 7,528 bbls of slickwater, 47 bbls of 15% HCl placing 76,061 lbs of 100 mesh and 125,666 lbs of 40/70 mesh silica sand. The treatment was pumped down 2,498.5 m of 4-1/2" P-110 15.1# Casing at an average rate of 37.6 bpm with an average pressure of 8,665 psi and a maximum sand concentration of 2.0 ppg. Initial well head pressure was 97 psi. The final bottom hole ISIP was 8,967 psi (1.077 psi/ft). Total fluid load is 7,575 barrels or 7,691 barrels including the wellbore volume. The treatment ended at 16:38 hrs.

Net pressure history matching suggests a moderately complex fracture geometry with propped fracture half-lengths of approximately 46 m and cumulative sand concentrations of ~ 0.8 lb/sqft. The sand and sand concentration should be of sufficient concentration and strength for a short term production test; however, higher quality proppant should be considered for long term production in a development program.

Fracture closure pressure was observed during the DFIT prior to the fracture treatment and helped calibrate the fracture model for the given formation idiosyncrasies. A fracture closure pressure gradient of 0.795 psi/ft was observed. Incorporation of this value into the Hubert and Willis equation, which relates fracture closure pressure to pore pressure, suggests the reservoir pressure is on the order of 0.653 psi/ft to 0.556 psi/ft depending on the Poisson’s ratio assumed.

\[ P_{fc} = (\gamma/(1-\gamma)) \times (1-P_i) + P_i + T \]

Where:

- \( P_{fc} \) =Fracture closure pressure (0.795 psi/ft)
- \( \gamma \) =Poisson’s ratio (assumed 0.29 to 0.35)
- \( P_i \) =Reservoir pressure (calculated to be 0.653 psi/ft to 0.556 psi/ft)
- \( T \) =Tectonic effects (assumed to be 0 in this area)

The average permeability modeled during the stage 2 fracture treatment was an order of magnitude higher than the stage one lower interval as predicted with the petrophysical model.
3.2.2 Flow Back Summary:

The well was opened to flow on 20 October, 2011 at 04:10 on a 6/64” choke with well head pressure of 4,730 psi. During the 12 hour shut-in period after the fracture treatment, significant amounts of gas entered the fracture as fluid redistributed in the system. Early flow initial gas rates were as high as 84 Mcfpd with 3,200 bbls of water per day. While this is not a production test, it does corroborate the petrophysical assessment suggesting the Middle Velkerri “B” is a gas reservoir. The measured gas specific gravity was between 0.638 and 0.704 with CO2 concentrations from 0% to 8%.

From 20 October through 24 October, the well flowed utilizing N2 assist at times to help recover the treatment fluid to the extent a stable gas rate might be recorded. Gas flow was restricted by loading effects as the rate was not above the critical velocity to unload water from the tubular configuration (1.75” CT in 4 ½” 15.1# casing). That critical rate at 200 psi is ~ 1,000 Mcfpd which is achieved by pumping N2 at 700 scf/min. The process was designed to lift the fluid from the casing above critical rate then drop the N2 rate to 500 scf/min or lower which allowed fluids (gas and water) to enter the wellbore. The backpressure caused by pumping 700 scf/min prevented production; however, each time the well was circulated above critical rate, significant amounts of water and gas were recovered with a large intermittent flare (N2 does not burn).

As in stage 1, water recovery has been good with over 50% of the load which is indicative of tight gas sands. There is no indication that formation water was being produced and none was expected. The increase in chlorides is believed to be associated with leaching of minerals from the formation and is normal in unconventional plays. In addition, the dye present in the fracture treatment fluid is in the samples.

Normally, measuring the gas rate is a two phase process. The first is to dewater the formation (recover the fracture fluid to the extent gas will flow) and the second is to test the gas rate. In this situation, a single micro-darcy interval will not produce gas at a sufficient rate to unload water from the tubular configuration. When the nitrogen was used to help unload the water, the bottomhole flowing pressure decreased to the point that the micro fractures may have closed. The micro-fractures that have been created contribute the bulk of the stimulated rock volume (SRV) and losing them further inhibits flow.

The flowback was indicative of a very low permeability reservoir which was not unexpected. Usually more zones are tested together to ensure sufficient gas rate at higher bottom hole flowing pressures exists to unload the well and achieve a steady test.

3.2.3 Post Frac DFIT:

On the evening of 24 October, 2011, the flow test was terminated for lack of measurable flow. Very little gas and no water were entering the wellbore and it appeared the micro-fractures and potentially the connection to the reservoir had been lost. A post frac DFIT was performed at 7:25 the morning of the 25th to attempt to determine the cause for the loss of flow. Once water was circulated into the well with CT, the pressure started building and was 300 psi with a full column of fluid just prior to starting the DFIT. The DFIT consisted of 24 bbls of water pumped at an average rate of 3.6 bpm and average casing pressure of 4,200 psi. The BH ISIP was 8,869 or 1.073 psi/ft. Closure pressure was observed in a few minutes and was determined to be 0.784 psi/ft. The good leak off suggests good communication to the reservoir through the fracture and discounts the notion of fluid sensitivity. It appears communication to
the micro-fracture network may have been lost when the casing was dewatered with N₂ and the bottom hole flowing pressure was unknown. Per the operational plan, the recovered load water (8,312 bbls) was pumped back into the reservoir.

3.2.4 Summary of Flow Back after Post Frac DFIT and Water Disposal Operations:

After injecting the recovered flow back water into the Middle Velkerri “B” perforations, the plan was to set a CIBP and perforate the Lower Moroak (stage 3). However, the injection of ~8,300 bbls of water into the formation resulted in a shut in casing pressure of over 5,800 psi. The pressure had to be relieved prior to running the gauge ring and junk basket in the well as the high casing pressure would not let them drop from the lubricator into the casing.

As the flow back was initiated at 03:45 on 26 October, 2011, gas in conjunction with the load water was observed very quickly (a casing volume). The pressure dropped very slowly and the water and gas rate increased to measureable rates of over 2,000 bwpd and ~60 Mcfpd, respectively (Figure 3.2.4.A). The SG of the gas at that time was 0.604 with 2% CO₂ and later was 0.648 with 4% CO₂. Core Labs compositional analysis of formation gas collected from the separator during Stage 2 (Sample No. 1 and 2) is included in Appendix XI.

The well was flowed until ~11:00 on 26 October, 2011 when it was shut in to run the gauge ring and junk basket at 11:17 on 26 October, 2011. The shut in casing pressure surprisingly was still 3,374 psi and built to 4,210 psi in a few minutes after flowing for approximately 7.5 hours.

The gauge ring and junk basket run recovered several pebble size pieces of shale and sandstone material that had migrated through the perforations (Figure 3.2.4.A). This material and size gradation may have occluded the perforations restricting flow until the load water was pumped back into the reservoir reestablishing communication to the reservoir. Apparently disposing of the load water into the stage 2
perforations established a conduit to the micro-fracture network as well accounting for the production response.

Figure 3.2.4.A Stage 2: Middle Velkerri B - Shale and sandstone pebbles.

The pressure built up to 4,210 psi during the gauge ring and junk basket run so the well had to be opened once again to drop the pressure to a manageable level to run the bridge plug. With the well flowing effectively with steady measurable gas rates, it was decided to flow the well an additional 12 hours prior to running the bridge plug and abandoning the Middle Velkerri “B”. At the end of the flow period, the well was flowing at 150 psi at ~ 35 Mscfpd and ~1,600 bwpd on a 32/64” choke. The well was shut in at 03:24 on 27 October, 2011 to run the CIBP. The casing pressure increased to 2,000 psi in 6 minutes, 2,400 psi in 15 min and 2,488 psi in 30 min suggesting good communication to the reservoir and good pressure after flowing for over 14 hours.

3.2.5 Reservoir Permeability:

The modeling of the DFIT data and fracture treatment results has a good correlation with the core derived petrophysical model. The average permeability over the rock contacted by the DFIT and stimulation is ~ 0.006 md (6,000 nd). The log derived permeability from the core based model developed prior to the Middle Velkerri B stimulation and test for porosity greater the 5% had an average ~ 0.06 md (60,000 nd). There is no core data in the Beetaloo Basin for Middle Velkerri Sandstone. Therefore the log porosity/permeability relationship established for the Stage 1, Middle Velkerri Lower B test is modified to fit the Stage 2, DFIT and stimulation results. The updated log derived average permeability (K) = 0.125 md (125,000 nd) for the Middle Velkerri B using a cutoff of PHIE > 0.05, Net Pay (H) = 18.5 m. Therefore the deliverability (K*H) of the Middle Velkerri B is estimated to be 2.23 md meters.
3.2.6 Reservoir Gas Saturation:

The log model for gas saturation is represented graphically by a Pickett Plot (Figure 3.2.6.A). This plot is interpreted to be a very strong indication that the intergranular porosity greater than 5% is gas saturated. Using a 5% porosity cutoff, Net Pay=18.5m, Avg. PHIE=0.073, Avg. SW=0.30 and Avg. Permeability=0.12 md for the Middle Velkerri B sands.

Figure 3.2.6.A Stage 2: Middle Velkerri B - log derived Pickett Plot
3.2.7 Composite Petrophysical Interpretation (CPI) Plot:

Additional untested sands within the Middle Velkerri A interval are interpreted to be very similar to the sands that produced gas during the Stage 2, Middle Velkerri B test (Figure 3.2.7.A). The Middle Velkerri A interval has; Net Pay = 21 m, Avg. PHIE=0.69, Avg. SW=0.36 and Avg. Permeability=0.095 md (95,000 nd). Deliverability K*H=2.0 md meters.

Figure 3.2.7.A Middle Velkerri A&B - CPI plot with updated permeability model
3.3 Stage 3: Middle Moroak Deltaic Sandstone

The Stage 3 completion and testing was performed over the Middle Moroak Deltaic interval 1837-1910 meters, measured depth. At the Shenandoah-1A location the Middle Moroak section is interpreted to be very low porosity sands with shale laminations. There is only a subtle mud log gas increase over this completion interval (Figure 3.3.5.A).

3.3.1 Breakdown Treatment:

On 28 October, 2011, Halliburton Energy Services pumped a DFIT into the Lower Moroak SS. The treatment consisted of 32 bbls of 13.5% HCl and 12.6 bbls fresh. The treatment was pumped at an average injection rate of 8.3 bpm at an average treating pressure of 5,662 psi. Initial well head pressure was 64 psi. The final bottom hole ISIP was 7,469 psi (1.215 psi/ft). Total fluid load is 44.6 barrels or 133.7 barrels including the wellbore volume to bottom perf. Production testing commenced after monitoring the shut-in pressure until 21:30 hours on 28 October, 2011.

The perforations broke after pumping 2.1 bbls. The breakdown pressure was 6,183 psi at 8.3 bpm. The total volume pumped into the formation after the breakdown was 42.5 bbls. A single definitive transient change was observed at 5,110 psi (0.831 psi/ft). This event is interpreted as closure of an adjacent layer to the Lower Moroak and not the final fracture closure pressure.

However, assuming a fracture closure pressure of 0.70 psi/ft in the Lower Moroak sandstones and incorporating it into FracPro, results in a leakoff coefficient of 0.00025 ft/(min)^1/2. This leakoff corresponds to a permeability of 0.000913 md under the given conditions.

Again, assuming a fracture closure pressure gradient of 0.70 psi/ft in the Lower Moroak and incorporating it into the following equation (Hubert and Willis), suggests a pore pressure in the Lower Moroak on the order of 3,030 psi (0.493 psi/ft):

\[ P_{fc} = \frac{\gamma}{1-\gamma} - (1-P_i) + T \]

Where:

- \( P_{fc} \) = Fracture closure pressure (0.7 psi/ft)
- \( \gamma \) = Poisson’s ratio (assumed 0.29)
- \( P_i \) = Reservoir pressure (calculated to be 0.493)
- \( T \) = Tectonic effects (assumed to be 0 in this area)

Please note that the value presented above is an estimate and the actual reservoir pressure could be significantly different based on the actual fracture closure pressure and Poisson’s ratio.
3.3.2 Flow Back:

The well was opened on 28 October, 2011 at 21:30 on a 20/64” choke with well head pressure of 2,125 psi. The well blew down to 15 psi in 1 minute. The coil tubing unit was sitting on the wellhead and at 21:46 began in the well with nitrogen at a rate of 300 scfpm. The rate was increased to 700 scfpm once on bottom and pumped until 04:50 on 29 October, 2011 when the nitrogen was shut down and coil tubing pulled out of the well. The reported total load recovered was 254.5 bbls; however, the efficiency of the flow turbine can be off as much as 100% when metering acid. In addition, pockets of gas hit the turbine causing it to spin giving a false reading. The last fluid recovered was the last of the acid (pH=3.0) so it is reasonable to assume no additional formation fluid had been recovered.

Given the observed low permeability, it is not surprising the well did not flow without a fracture treatment. Reservoir simulation of these data suggests a gas rate (without load water inhibiting flow) of approximately 5 to 10 mscf/d, see Figure 3.3.2.A.

**Figure 3.3.2.A Stage 3: Predicted unstimulated production response for the Middle Moroak**

![Figure 3.3.2.A Stage 3: Predicted unstimulated production response for the Middle Moroak](image-url)
3.3.3 Reservoir Permeability:

Modeling of the DFIT data indicates low permeability over the Stage 3, Moroak Deltaic interval. The average permeability over the rock contacted by the DFIT is ~0.000913 md (913 nd).

The Moroak log derived permeability from the core based model developed prior to the Shenandoah-1A well test is from core data on the Elliott #1 well in the Southern Beetaloo Basin. The Moroak Deltaic core permeability in the Elliott #1 well ranges from 0.01-1.67 md vs. core porosity of 0.036-0.078. This relationship is higher than the relationship established by the Stage 3, DFIT results in Shenandoah-1A.

The Moroak Deltaic log permeability model is edited for the Shenandoah-1A well to fit the Stage 3, DFIT results. The update log model results in a lower permeability vs. porosity relationship throughout the Moroak Deltaic Sandstones.

3.3.4 Reservoir Saturation:

The log model for Moroak water saturation is represented graphically by a Pickett plot (Figure 3.3.4.A). Applying the RW from SP analysis from a relatively porous Moroak Sand (2035-2060 m) confirms the SP result and establishes the formation resistivity factor (m=2.1) used in the Archie water Saturation equation. The mud log response from Shenandoah-1A indicates the potential for gas in this Moroak Sand, but log analysis indicates that the Moroak Sand (2035-2060 m) is most likely wet.

Figure 3.3.4.A Moroak water saturated sand - RW model
Due to borehole rugosity over the Stage 3, Moroak Deltaic interval, porosity from the sonic log (PORSWSS) is used to confirm the Pickett Plot interpretation (Figure 3.3.4.B). The very low porosity (PORSWSS=0.05) calculated over the Stage 3 Moroak is interpreted as irreducible water and most likely will not flow significant gas.

Figure 3.3.4.B Stage 3: Moroak Deltaic, very low porosity, water saturated sand
3.3.5 Composite Petrophysical Interpretation (CPI) Plot:

Figure 3.3.5.A Stage 3: Moroak Deltaic - CPI plot with updated permeability model
3.4 Stage 4: Moroak Fluvial Sandstone

The Stage 4 completion and testing was performed over the Moroak Fluvial interval 1728-1780 meters measured depth. At the Shenandoah-1A location the Upper Moroak section is a massive fluvial sandstone with indications of natural fractures from the STAR image log. There were modest mud log gas shows over this completion interval, however the shows dissipate over the porous interval @ 1806 m (Figure 3.4.5A).

3.4.1 Breakdown Treatment:

On 30 October, 2011, Halliburton Energy Services pumped a DFIT into the Upper Moroak SS. The treatment consisted of 9 bbls of fresh water containing 25 bio-balls (water soluble diverting agent), 28.2 bbls 15% HCl with 124 bio-balls displaced with 85.8 bbls of fresh water. The balls were then surged from the perforations and let fall below. Injection was again established with a total of 12.6 bbls of fresh water. The treatment was pumped at an average rate of 8.4 bpm, with an average pressure of 5,100 psi. The final bottom hole ISIP was 6,614 psi (1.150 psi/ft). Total fluid load is 135.2 barrels or 218.2 barrels including the wellbore volume to bottom perforation. Production testing commenced after monitoring the shut-in pressure until 10:05 hrs. (6 hr shut-in) on 30 October, 2011.

The perforations broke after pumping 1.7 bbls. The breakdown pressure was 4,440 psi at 3.5 bpm. The total volume pumped into the formation after the breakdown was 133.5 bbls. A single definitive transient change was observed at 4,650 psi (0.808 psi/ft). This event is interpreted as closure of an adjacent layer to the Lower Moroak and not the final fracture closure pressure.

However, assuming a fracture closure pressure of 0.70 psi/ft in the Upper Moroak sandstones and incorporating it into FracPro, results in a leakoff coefficient of 0.002 ft/(min)$^{1/2}$. This leakoff corresponds to a permeability of 0.073 md under the given conditions.

Again, assuming a fracture closure pressure gradient of 0.70 psi/ft in the Upper Moroak and incorporating it into the following equation (Hubert and Willis), suggests a range of pore pressure in the Upper Moroak on the order of 3,165 psi (0.550 psi/ft) to 2,837 psi (0.493 psi/ft):

$$P_c = (\frac{\gamma}{1-\gamma}) (1-P_r) + P_r + T$$

Where:

- $P_c$ = Fracture closure pressure (0.7 psi/ft)
- $\gamma$ = Poisson’s ratio (assumed 0.25 to 0.29)
- $P_r$ = Reservoir pressure (calculated to be 0.550 to 0.493)
- $T$ = Tectonic effects (assumed to be 0 in this area)

Please note that the value presented above is an estimate and the actual reservoir pressure could be significantly different based on the actual fracture closure pressure and Poisson’s ratio.
3.4.2 Flow Back Summary:

The well was opened on 30 October, 2011 at 10:05 on a 16/64” choke with well head pressure of 974 psi. Nitrogen was started almost immediately (10:14) while running coil tubing to bottom in order to unload the wellbore as soon as possible. This would hopefully facilitate the recovery of the treatment fluid and potentially get a gas rate and/or a reservoir water sample. Nitrogen was circulated just above the perforations until the casing volume was recovered and then dropped below the perforations to help lift any fluid entering the wellbore. After circulating N₂ for 1 hour, the N₂ was shut down to see what the well would do on its own.

No fluid (gas or water) entered the wellbore after the N₂ was shut down. There was never any gas substantial enough to detect as all gas gravities indicated nitrogen (specific gravity of 0.98). With the rathole circulated clean of any potentially corrosive acid and no further fluid entry, the CT was brought to surface in order to move on to stage 5. The total load recovered was 147 of 218 bbls.

3.4.3 Reservoir Permeability:

Modeling of the acid injection data indicates low permeability over the Stage 4, Upper Moroak Fluvial interval but higher than the Stage 3, Moroak Deltaic interval. The average permeability over the rock contacted by the acid injection is ~0.0829 md (82,900 nd).

The image log (STAR) run over the Moroak in the Shenandoah-1A identifies significant high angle natural fractures over the Upper Moroak down to 1795 m. The Stage 4 test was designed to contact the naturally fractured interval (1728-1780 m). These natural fractures may provide the permeability that the Stage 4 test has contacted.

The Moroak log derived permeability from the core based model developed prior to the Shenandoah-1A well test is from core data on the Elliott #1 well in the Southern Beetaloo Basin. The Upper Moroak Fluvial core permeability in the Elliott #1 well ranges from 0.01-274 md vs. core porosity of 0.01-0.092. This relationship is higher than the relationship established by the Stage 4, acid treatment results in Shenandoah-1A.

The Upper Moroak Fluvial log permeability model is edited for the Shenandoah-1A well to fit the Stage 4, acid stimulation results. The update log model results in a lower permeability vs. porosity relationship than the initial core based model but it is higher than the result from the Stage 3, Moroak Deltaic interval.
3.4.4 Reservoir Gas Saturation:

The Pickett Plot (Figure 3.4.4.A) over the Stage 4, Upper Moroak Fluvial indicates the potential intervals with high water saturation, particularly intervals where porosity increases. Neither significant formation gas nor water was produced during the Stage 4, test indicating the fractures may be closed and contain very little if any formation fluids.

Figure 3.4.4.A Stage 4: Moroak Fluvial - Pickett Plot
3.4.5 Composite Petrophysical Interpretation (CPI) Plot:

Figure 3.4.5.A Stage 4: Moroak Fluvial - CPI plot with updated permeability
3.5 Stage 5: Lower Kyalla

The Stage 5 completion and testing was performed over the Lower Kyalla interval 1631-1649 meters measured depth. At the Shenandoah-1A location the Lower Kyalla section is interpreted to be a source rock with TOC ~ 2 wt% composed of shale/siltstone and sandstone layers. Mudlog gas shows are very high over the Lower Kyalla reaching 11% total gas (Figure 3.5.5.A).

3.5.1 Fracture Treatment:

On 31 October, 2011, Halliburton Energy Services pumped the stage 5 fracture treatment into the Lower Kyalla formation. The treatment consisted of 7,834 bbls of slickwater, 32 bbls of 15% HCl placing 69,447 lbs of 100 mesh and 158,736 lbs of 40/70 mesh silica sand. The treatment was pumped down 1,659 m of 4-1/2" P-110 15.1# Casing at an average rate of 50.4 bpm with an average pressure of 5,630 psi and a maximum sand concentration of 2.0 ppg. Initial well head pressure was 37 psi. The final bottom hole ISIP was 5,643 psi (1.049 psi/ft). Total fluid load is 7,866 barrels or 7,943 barrels including the wellbore volume. The treatment ended at 15:58 hrs.

A DFIT was not performed prior to stage 5; thus, a fracture closure pressure was assumed to be 0.795 based on the petrophysical similarity to the Middle Velkerri.

Again, assuming a fracture closure pressure of 0.795 psi/ft in the Lower Kyalla and incorporating it into FracPro, results in a leakoff coefficient of 0.0003 ft/(min)^1/2. This leakoff corresponds to a permeability of 0.00219 md under the given conditions.

Utilizing the Hubert and Willis equation, which relates fracture closure pressure to pore pressure, with a fracture closure gradient of 0.795 psi/ft suggests the reservoir pressure is on the order of 0.653 psi/ft to 0.556 psi/ft depending on the Poisson’s ratio assumed.

\[
P_{fc} = \frac{\gamma}{(1-\gamma)}(1-P_i) + P_i + T
\]

Where:

- \(P_{fc}\) = Fracture closure pressure (0.795 psi/ft)
- \(\gamma\) = Poisson’s ratio (assumed 0.29 to 0.35)
- \(P_i\) = Reservoir pressure (calculated to be 0.653 psi/ft to 0.556 psi/ft)
- \(T\) = Tectonic effects (assumed to be 0 in this area)

Please note that the value presented above is an estimate and the actual reservoir pressure could be significantly different based on the actual fracture closure pressure and Poisson’s ratio.

Net pressure history matching suggests a complex fracture geometry with propped fracture half-lengths of approximately 39 m and cumulative sand concentrations of ~ 0.92 lb/sqft. The sand and sand concentration should be of sufficient concentration and strength for a short term production test; however, higher quality proppant should be considered for long term production in a development program.
3.5.2 Flow Back Summary:

The well was open to flow on 31 October, 2011 at 22:30 on a 16/64” choke with well head pressure of 2,851 psi. During the 6.5 hour shut-in period after the fracture treatment, significant amounts of gas entered the fracture as fluid redistributed in the system. Burnable gas was observed after one wellbore volume had been recovered (Figure 3.5.2.A). The specific gravity of the gas was 0.708 with 1% CO₂. Additional analysis of Lower Kyalla, separator gas is provided by Core Labs (Appendix XII).

Based on the performance of Stage2, care was given not to flow the formation too hard and the choke was held on a 16/64 until approximately 15:40 on 1 November, 2011 when nitrogen was started at 300 scfm. The casing pressure had fallen to ~ 480 psi.

The nitrogen rate was maintained at 300 scfm until the water rate dropped off at which time it was turned off. This allowed fluid and gas to enter the wellbore but did not have sufficient velocity to unload the casing; thus, N₂ rate was again establish to unload the casing. This resulted in a large slug of water and gas through the test equipment. This was done until the flowback was terminated at ~ 06:00 on 3 November, 2011. A total of 2,419 bbls of fluid had been recovered out of 7,943 bbls pumped or 30%.

Figure 3.5.2.A Stage 5: Lower Kyalla - unassisted gas flare.
3.5.3 Reservoir Permeability:

Modeling of the stimulation data indicates low permeability over the Stage 5, Lower Kyalla interval. The average permeability over the rock contacted by the Stage 5 stimulation is ~0.002190 md (2,190 nd). This is low permeability and may require long lateral well bores to contact sufficient permeable formation to produce at significant rates.

The log derived permeability from the core based model developed prior to the Lower Kyalla stimulation and test for porosity greater the 5% had an average ~ 0.025 md (25,000 nd). The only Lower Kyalla core that is available for the center of the Beetaloo Basin is from the Shenandoah-1A, Core 1 (1585-1596 m). Core 1 is 20 m above the Lower Kyalla “sweet spot” (1615-1655 m). The Lower Kyalla permeability model is edited to incorporate the results from the Stage 5 stimulation. The updated log derived average permeability (K) for the Lower Kyalla using a cutoff of PHIE > 0.05 is ~ 0.02 md (20,000 nd), net pay (H) = 48 m. Therefore the deliverability (K*H) of the Lower Kyalla is estimate at 0.96 md meters.

3.5.4 Reservoir Gas Saturation:

The log model for gas saturation is represented graphically by a Pickett Plot (Figure 3.5.4.A). The Pickett Plot over the Stage 5, Lower Kyalla indicates that as porosity increases gas saturation also increase. Assuming a bulk volume of irreducible water=0.04 and applying a 4% porosity cutoff, the Lower Kyalla has 48 m net pay with an Avg. PHIE = 0.071, TOC = 0.02, SW = 0.36 and Avg. Permeability = 0.02 md.

The initial flow back of the Stage 5 stimulation has demonstrated that producible gas is present in the Lower Kyalla. However there is a possibility that the Lower Kyalla stimulation has connected to the Upper Moroak fracture system and that Moroak water may flowing into the Lower Kyalla and loading up the well with water limiting the flow of gas during the Stage 5 test.

Figure 3.5.4.A  Stage 5: Lower Kyalla - Pickett Plot.
3.5.5 Composite Petrophysical Interpretation (CPI) Plot:

Figure 3.5.5.A Stage 5: Lower Kyalla - CPI plot with updated permeability model