St. Flavien Facility

Procedures and Cost Summary for Recommended Well Interventions
Mar 2, 2022

Privileged and Confidential

Presented to:

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ACRONYMS

Acronym	Description
AER	Alberta Energy Regulator
BC OGC	British Columbia Oil and Gas Commission
BOP	Blowout Preventor
CSA	Canadian Standards Association
EUE	External Upset End
MOP	Maximum Operating Pressure
OH	Open Hole
SFL	St. Flavien

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EXECUTIVE SUMMARY

Behr Integrated Solutions Inc. (Behr) was engaged to conduct a review of the wells in the St. Flavien field. There are a total of nine (9) vertical wells and six (6) horizontal wells in the field. Four (4) of the nine (9) vertical wells are used for observation purposes.

The status of each of the wells was reviewed and workover recommendations, with timeline estimates, to complete the work were provided.

A cost estimate has been prepared on the basis that seven (7) distinct mobilizations will be required to conduct the operations on all the wells. On this basis, a cost of $8,377,000 is estimated (in 2021 dollars) to complete the work. Intragaz should make provisions to conduct the work on all the wells over the next 15 to 20 years.

Ultimately, after this round of workovers is complete, the St. Flavien field will be consistent with best practices outlined the CSA Z341 standard. Afterwards, maintaining guidance outlined in this standard is recommended.

A summary report titled "St. Flavien Facility, Review of Wells and Recommendations for Well Interventions" dated March 2, 2022, provides background related to the proposed operations.

INTRODUCTION

Behr Integrated Solutions Inc. (Behr) has been engaged by Intragaz Inc. (Intragaz) to review the status of the wells in the St. Flavien field and provide forward looking recommendations for well interventions. The review incorporates the following considerations:

- The status of the wells
- Monitoring results
- Regulatory requirements
- Standards and best practices.

From this information, an outline of steps required for the well interventions has been prepared. Additionally, priorities for the order of the work have been set. Finally, costs for the proposed work, in 2021 dollars are provided.

The specific steps of the workover may be amended when the schedule time of work approaches. The availability, type and proximity of services may influence procedural decisions. Additionally, new technologies may become available which could result in procedural changes. Regardless, the objective of the workovers will remain the same.

RECOMMENDATIONS OF WELL INTERVENTIONS

The following table provides a maintenance overview for the next sequence of well workovers.

Well		Workover Objective
Name	Status	
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Annex 1 includes the following detailed information to accomplish the workover objectives:

- Background and ongoing maintenance considerations
- Forward-looking recommendations
- Suggested workover overview
- Expected workover timeline.

OPERATIONS AND COST ESTIMATE

Cost estimate to complete workover schedule

Code		INTANGIBLE COMPLETION COST	Mobilization Costs (7 Mob's)	Site Costs	Total Cost
930	058	Rig Move in/out (includes Camp move)	[redacted]	[redacted]	[redacted]
930	063	Service rig - Daywork	-	[redacted]	[redacted]
930	064	Mud and Chemicals	-	[redacted]	[redacted]
930	068	Crew travel, Subsistence and camp	-	-	-
930	069	Water & Water hauling	-	[redacted]	[redacted]
930	070	Boiler	-	-	-
930	071	Communications	-	-	-
930	072	Equipment Rentals - BOP Equipment	-	[redacted]	[redacted]
930	072	Equipment Rentals Drill Pipe and Collars	-	-	-
930	072	Equipment Rentals - Power Swivel	-	-	-
930	072	Equipment Rentals - Power Plant	-	-	-
930	072	Equipment Rentals - Other	-	[redacted]	[redacted]
930	074	Fuel and Lubricants	-	-	-
930	081	Wellsite supervision	[redacted]	[redacted]	[redacted]
930	083	Engineering services	-	[redacted]	[redacted]
930	090	Trucking and Hauling	[redacted]	[redacted]	[redacted]
930	091	Tank Truck and Fluid Hauling	-	-	-
930	094	Fluid Disposal (Vacuum Truck)	-	-	-
930	098	Fishing Services	-	[redacted]	[redacted]
930	100	Casedhole Logging & Perforating	-	[redacted]	[redacted]
930	102	Safety services	-	-	-
930	104	Environmental services	-	-	-
930	109	Wireline Services & Recorders	-	[redacted]	[redacted]
930	110	Pickup/Laydown/Torque Services	-	[redacted]	[redacted]
930	111	Thread Supervision Services	-	[redacted]	[redacted]
930	112	Coil Tubing / N2 Services	-	[redacted]	[redacted]
930	115	Snubbing Equipment	-	-	-
930	126	Packer Equipment Supervision	-	[redacted]	[redacted]
930	139	Cement & Services - Primary or Remedial	-	-	-
		Subtotal:	[redacted]	[redacted]	[redacted]
Code		**TANGIBLE COMPLETION**			
940	054	Wellhead, Assembly and Installation	-	[redacted]	[redacted]
940	105	Production Tubing	-	[redacted]	[redacted]
940	105	Production Casing	-	-	-
930	108	Downhole equipment (Except BH pumps)	-	[redacted]	[redacted]
		Subtotal:	-	[redacted]	[redacted]
Code		**GENERAL**			
930	130	Miscellaneous	-	-	-
930	199	Contingency (25%)	[redacted]	[redacted]	[redacted]
930	500	Non-Op ICC	-	-	-
930	129	Overhead 3/2/1 or ______________	-	-	-
		Subtotal:	[redacted]	[redacted]	[redacted]
		TOTAL	2,303,000	6,074,000	8,377,000

Details of the individual well costs are shown in Annex 2. A 25% contingency has been applied. Factors such as the remoteness of most services, uncertainty in the availability of equipment or services, competitiveness of the industry at the time of operations all contribute to the need for a high contingency. In addition, unforeseen circumstances that arise during a workover are more complex and costly to resolve, as mobilization of equipment for resolution of the circumstance will often involve distant service requirements (as far away as Alberta) with costly delays and mobilizations.

The cost estimate is based on seven (7) distinct mobilizations. The separation of time between mobilizations could range between one (1) and three (3) years and may be influenced by equipment location and availability.

CONCLUSIONS

Each of the wells in the St. Flavien field have been reviewed. Based on the review, priorities have been assigned to conduct workovers, which are described in a report titled, “St. Flavien Facility, Review of Wells and Recommendations for Well Interventions”, dated March 2, 2022.

A cost estimate has been prepared on the basis that seven (7) distinct mobilizations will be required to conduct the operations on all the wells. Each mobilization may be separated by anywhere from one (1) to three (3) years, depending on proximity and availability of services. On the basis of seven (7) mobilizations, a cost of $8,377,000 is estimated (in 2021 dollars) to complete the work.

ANNEX 1 – [redacted]

Well Name: [redacted]

Permit #: [redacted]

Background and Ongoing Maintenance Considerations

1) This well was originally drilled in 1972.
2) The burst rating for the intermediate casing string and the liner is 64.47 MPa and 30.2 MPa respectively.
3) The liner top consists of a hanger/packer device. Import tool, the supplier of the liner top, has indicated the liner top should withstand a pressure test of 21 MPa. The full length of the liner is cemented, so hydraulic isolation from the cement is probable.
4) Perforations in the intermediate casing straddle the base of the Trenton and top of the Chazy formations. This interval is tight and did not produce gas.
5) The most recent workover was in July 2005. During this workover, a casing inspection log was run and a retrievable casing patch was positioned over the Trenton/Chazy perforation interval.
6) The retrievable casing patch that straddles the Chazy is rated for a differential pressure of 21 MPa. To leave a 1.6 safety factor on the rated differential pressure, the recommended maximum pressure test has been limited to 7.0 MPa. The Chazy pressure is about 6 MPa. Therefore, with 7.0 MPa surface pressure on the annulus, the differential pressure on the patch is about 13.3 MPa. To take the patch to 100% of its rated differential pressure, the maximum surface pressure should not exceed 14.6 MPa or about 77% of the maximum operating pressure.
7) Given that a tubing string is in the wellbore, the next casing inspection log is not due until 2025 if protocols for CSA Z341 are followed. However, pressure tests on the casing should be conducted every 5 years. To completely comply with the CSA Z341 standard, the pressure test should be to 1.1 times the maximum operating pressure of the well, or about 22 MPa.
8) The week point in the wellbore is likely the casing patch. A tubing failure could cause the casing patch to rupture. However, the Trenton/Chazy is relatively tight and the MOP is well below the fracture gradient for the Trenton/Chazy. Therefore, there is not a significant risk associated with a casing patch failure.

Recommendations

1) Continue annual pressure tests on the annulus to a surface pressure of 7 MPa until the next workover
2) Conduct workover to achieve the following objectives:
    a. Conduct casing inspection logs down to about 1440 m KB (just above the isolation packer for the Beekmantown formation.)
    b. Pressure test the casing above and below the Trenton/Chazy formation to 22 MPa (down to the isolation packer).

c. Straddle the Chazy perforations with hydraulic-set retrievable packers that are rated to 50 MPa or above and run a sliding sleeve below the straddle packer set so that the annulus below the straddle packers can be subsequently pressure tested to 22 MPa at least once every five years.
d. Increase the annual pressure tests on the annulus above the straddle packers to 22 MPa.

Workover Overview

[redacted]

[redacted]

Workover Timeline

Description of Operations			Number of days					
[redacted]	Hours	Cum Hours	Day	Serv R	Sup	Packer Rep	Slickline	Logging
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Standby Days							[redacted]	

ANNEX 1 – [redacted]

Well Name: [redacted]

Permit #: [redacted]

Background and Ongoing Maintenance Considerations

1) [redacted] was originally drilled in 1976, The last workover was in 2016.
2) In the 2016 workover, a retrievable casing patch was replaced with a set of hydraulic packers that straddle the Trenton perforations. A sliding sleeve below these packers enables the upper and lower wellbore to be pressure tested.

[redacted]

8) There are two packers and a sliding sleeve between the Beekmantown B and C. If the zones are ever to be isolated during the service life of the well, the packers between the two zones could be pressure tested through a combination of setting an internal plug below the isolating packer set, closing sleeves above the packer set and opening the sleeve between the packer set. However, there is little need to pressure test these packers as all of the sleeves are open and the two zones are producing in communication.
9) There are three isolation packers stacked above each other just above the upper Beekmantown B perforations. The additional packers were installed to address leaks from the previously installed packers.

[redacted]

[redacted]

[redacted]

[redacted]

For this report, the casing repair option is outlined in detail, rather than cementing an internal string. If a decision was made to cement an internal string into [redacted] then the cost of the site costs of the operation (including tubulars) is estimated at $688,000, including a 25% contingency.

Workover Overview

[redacted]

[redacted]

[redacted]

Workover Timeline

Description of Operations		Cum Hours	Number of days				
[redacted]	Hours		Day	Serv R	Sup	Packer Rep	Slickline
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Total		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Standby Days							[redacted]

ANNEX 1 – [redacted]

Well Name: [redacted]

Permit #'s: [redacted]

Background and Ongoing Maintenance Considerations

1) [redacted] was originally drilled in 1984, The last workover was in 2010.
2) After the well was drilled, open-hole abandonment plugs were placed across the Beekmantown zones, The top of these cement plugs is at 1420 m KB. Surface casing with a 244.5 mm OD was landed at 298 m KB.
3) The open hole section between the surface casing shoe and the cement top was left open for monitoring until 2010, when 177.8 mm 338.7 kg/m J55 production casing, with a burst rating of 34,340 kPa was set into the well at 1253 m KB.
4) [redacted]
5) Pressure has been maintained below 8,400 kPa on this well. Continued observation is prudent.
6) This well is strictly an observation well that is not used for injection or withdrawal, and it is not completed in the primary storage horizon. Consequently, the CSA standard and other gas storage well practices do not directly apply to this well. Nonetheless, continued monitoring of the well is appropriate. When tubing is pulled from this well, a casing inspection log is recommended.
7) Given the low operating pressure of the well, the risk associated with a casing failure is very low.

Workover Overview

[redacted]

[redacted]

Workover Timeline

Description of Operations		Cum Hours	Number of days			
[redacted]	Hours		Day	Serv R	Sup	Logging
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Total		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

ANNEX 1 – [redacted]

Well Name: [redacted]

Permit #'s: [redacted]

Background and Ongoing Maintenance Considerations

1) [redacted] was originally drilled in 1992, The last workover was also in 1992.
2) After the well was drilled, open-hole abandonment plugs were placed across the Beekmantown C zone, The top of the cement plug is at 1565 m KB. Surface casing with a 244.5 mm OD was landed at 300.8 m KB and production casing was landed at 1483.74 m KB. The production casing is 177.8 mm 38.7 kg/m N80 casing with a burst rating of 49,920 kPa.
3) The open hole section between the surface casing shoe and the cement top was left open for monitoring.
4) The well is completed with 73 mm tubing which includes a Baker Lokset packer, near the base of the casing at 1483.74 m KB. The base of the tubing is at 1504.13 m KB.
5) This casing has a burst pressure of 49,920 kPa or about 2.5 times MOP. Consequently, even if some corrosion is evident, the casing is likely above CSA requirements for pressure integrity. However, it is unclear if a casing inspection log has ever been run in this well, and at best the most recent log would be in May 1992, when the last workover was conducted.

Workover Overview

[redacted]

[redacted]

Workover Timeline

Description of Operations		Cum Hours	Number of days				
[redacted]	Hours		Day	Serv R	Sup	Slickline	Logging
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Total		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Standby Days						[redacted]	

ANNEX 1 – [redacted]

Well Name: [redacted]

Permit #'s: [redacted]

Background and Ongoing Maintenance Considerations

1) [redacted] was originally drilled in 1993, The last workover was in 1996.
2) The well was originally perforated in the Beekmantown C (from 1720 m – 1726 m KB). However, these perforations were abandoned with a bridge plug that was set at 1711 m KB and capped with an 8 m cement plug. Perforations in the Beekmantown B remain open and are used for injection and withdrawal. Surface casing with a 244.5 mm OD was landed at 203 m KB Production casing was landed at 745 m KB. The production casing is 177.8 mm 38.7 kg/m N80 casing.
3) The open hole section between the surface casing shoe and the cement top was left open for monitoring.
4) The well is completed with 73 mm tubing which includes a Baker Lokset packer, near the base of the casing at 1504 m KB. The base of the tubing is at 1514 m KB.
5) This casing has a burst pressure of 49,920 kPa or about 2.5 times MOP. Consequently, even if some corrosion is evident, the casing is likely above CSA requirements for pressure integrity. However, it is unclear if a casing inspection log has ever been run in this well, and at best the most recent log would be in May 1992, when the last workover was conducted.

Workover Overview

[redacted]

[redacted]

Workover Timeline

Description of Operations		Cum Hours	Number of days				
[redacted]	Hours		Day	Serv R	Sup	Slickline	Logging
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Total		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Standby Days						[redacted]	

ANNEX 1 – [redacted]

Well Name: [redacted]

Permit #'s: [redacted]

Background and Ongoing Maintenance Considerations

1) [redacted] was originally drilled in 1994, The last workover was in 2000.
2) Intermediate hole was drilled to 1116 m KB where 244.5 mm 59.5 kg/m N80 casing was set. The next intermediate hole section was drilled to 1525 m KB where a 177.8 mm 38.7 kg/m N80 liner was landed. The liner top is at 955.7 m KB. The tiner top has a packoff and a polished bore receptical on the liner top.
3) Import Tool, the supplier of the Liner Top Packer has indicated that the liner top can be pressure tested to 21 MPa.
4) Open-hole abandonment plugs in the bottom of the wellbore have isolated the Beekmantown C and Theresa formations. The Beekmantown B formation is open in the open-hole section with porosity indications from 1549.1 m to 1551.7 m KB. The base of the intermediate liner is landed at 1525 m KB.
5) Either thread leaks or on/off tool leaks have enabled pressure communication between the tubing and the annulus. However, the leak seems to be insignificant, and the communication is gradual in nature.
6) The last casing inspection log was conducted in May 2000. The well is due for the next casing inspection in 2020 in order to be compliant with CSA requirements.
7) Because the tubing head has a 228.6 mm 35 MPa tubing flange, either 228.6 mm or 279.4 mm BOPs will be required.
8) There are two packers in the hole including a 177.8 mm Guiberson AVA packer at 1507.7 m KB and a Guiberson UNI-VI packer at 1501.84 m KB. Each packer has an on/off tool although the J-slots are removed from the on/off tool on the lower packer.

Workover Overview

[redacted]

[redacted]

Workover Timeline

Description of Operations		Cum Hours	Number of days				
[redacted]	Hours	Cum Hours	Day	Serv R	Sup	Slickline	Logging
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]							
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]							
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]							
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Total		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Standby Days						[redacted]	

ANNEX 1 – [redacted]

Well Name: [redacted]

Permit #'s: [redacted]

Background and Ongoing Maintenance Considerations

1) [redacted] was originally drilled in 1994, The last workover was in 2017.
2) Intermediate hole was drilled to 1514 m KB where 177.8 mm 38.7 kg/m SOO55 casing was set. The open hole section was drilled into the Beekmantown B to a total depth of 1628 m KB
3) Prior to the last workover, the well was completed without a packer. When the tubing as pulled, scale was noted on the tubing on the bottom 100 joints. A high-resolution Vertilog was run at the time. The tubing was run back in with a packer and the annulus was pressure tested successfully to 20 MPa. The annulus is filled with inhibited water.
4) After the workover, pressure communication between the tubing and the annulus started. The tubing hanger seals are likely the source of the leak. [redacted]
5) An all-weather access road has recently been installed so access can be achieved at any time.

[redacted]

8) If a rig is in the area, then it would be appropriate to move a rig onto the well, kill the well, pull and replace the seals on the tubing hanger and reinstall and pressure test the wellhead and annulus. The annulus is full of inhibited fluid and has protection from further corrosion. The next casing inspection log timeline of twenty (20) years is appropriate.

Workover Overview

[redacted]

[redacted]

Workover Timeline

Description of Operations		Cum Hours	Number of days			
[redacted]	Hours		Day	Serv R	Sup	Slickline
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Total		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Standby Days						

ANNEX 1 – [redacted]

Well Name: [redacted]

Permit #'s: [redacted]

Background and Ongoing Maintenance Considerations

1) [redacted] was originally drilled in 1995, The last workover was in 1997.
2) The well was originally drilled into the Beekmantown C to a total depth of 1860 m. An abandonment plug was placed across the Beekmantown C with a top depth of 1650 m. 177.8 mm 38.7 kg/m L80 casing was run and landed at 1545 m KB and the Beekmantown B formation was perforated over a gross interval from 1578.2 m to 1592.2 m KB.
3) 73 mm tubing is landed at 1566.8 m KB and a production packer is set at 1552.77 m KB.
4) Packer details and the on/off tool details were not available at the time of this report preparation and will have to be confirmed prior to conducting workover. However, the on/off tool is likely equipped with a 58.75 mm X profile.
5) This casing has a burst pressure of 49,920 kPa or about 2.5 times MOP. Consequently, even if some corrosion is evident, the casing is likely above CSA requirements for pressure integrity. However, it is unclear if a casing inspection log has ever been run in this well.

Workover Overview

[redacted]

[redacted]

Workover Timeline

Description of Operations		Cum Hours	Number of days				
[redacted]	Hours	Hours	Day	Serv R	Sup	Slickline	Logging
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Total		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Standby Days						[redacted]	

ANNEX 1 – [redacted]

Well Name: [redacted]

Permit #'s: [redacted]

Background and Ongoing Maintenance Considerations

1) [redacted] was originally drilled in 1995, The last workover was in 1997.
2) The well was originally drilled into the Theresa to a total depth of 1860 m. The Theresa was peforated from 1761.5 m to 1771.5 m KB. A production packer and tail pipe was left in the wellbore and an abandonment bridge plug was set at 1737 m KB and a 7-m cement cap was placed above the bridge plug (with the top at 1730 m KB.
3) The Beekmantown C formation was perforated over a gross interval from 1671.55 m – 1696.55 m KB. The well is used as an observation well for the Beekmantown C.
4) 73 mm tubing is landed at 1668.13 m KB and a production packer is set at 1633.8 m KB.
5) Packer details and the on/off tool details were not available at the time of this report preparation and will have to be confirmed prior to conducting workover. However, the on/off tool is likely equipped with a 58.75 mm X profile. Additionally, a sliding sleeve at 1611.1 m KB also likely has a 58.75 mm X profile.
6) This casing has a burst pressure of 34,340 kPa or about 1.7 times MOP. Consequently, even if some corrosion is evident, the casing is likely above CSA requirements for pressure integrity.

Workover Overview

[redacted]

[redacted]

Workover Timeline

Description of Operations		Cum Hours	Number of days				
[redacted]	Hours		Day	Serv R	Sup	Slickline	Logging
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Total		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Standby Days						[redacted]	

ANNEX 1 – [redacted]

Well Name: [redacted]

Permit #'s: [redacted]

Background and Ongoing Maintenance Considerations

1) [redacted] was originally drilled and completed in 2000. A tubing inspection log was run in September 2011. The inspection log did not identify any defects.
2) 177.8 mm 38.7 kg/m L80 intermediate casing was set at an inclination of 79° in the lower portion of the tight Beekmantown A about 10 m above the top of the Beekmantown B formation. The open hole section is drilled to a total measured depth of 2414 m KB at a true vertical depth of 1491.2 m KB, with most of the horizontal length in the Beekmantown B formation.
3) The burst rating of the casing is 49,920 kPa, or about 2.5 times the maximum operating pressure. Consequently, even if some corrosion is evident, the casing is likely above CSA requirements for pressure integrity.
4) There are two packers isolating the formation from the annulus. The lower packer, which is set at 1450.42 m KB, is a permanent packer; and the upper packer, which is set at 1437.97 m KB, is a hydraulic set retrievable packer. An on/off tool with a 69.85 mm X profile is located immediately above the upper packer.
5) The tubing string is 88.9 mm 13.69 kg/m L80 tubing with New NK3SB connections.
6) The tailpipe below the lower packer is also 88.9 mm and extends to a depth of 1791,29 m KB.
7) The wellhead AOF for this well is about [redacted] m^3/d. The 88.9 mm tubing represents a considerable flow restriction. If the tubing string size diameter above the packers was increased to a 114.3 mm/127.0 mm tapered string, the wellhead AOF would be increased by an estimated [redacted] % to about [redacted] m^3/d.
8) Furthermore, if the tailpipe were perforated immediately below the lower packer to enable flow up the lower annulus and tubing. With enough perforations in the tubing just below the bottom profile, the wellhead AOF of this well could further increased by about [redacted] m^3/d to [redacted] m^3/d to about [redacted] m^3/d. This change would mean that flow would occur up the annulus to these perforations. Tubing punch charges should be used to avoid damaging the casing.
9) There is no urgency in conducting a workover, as the next casing inspection log is not due until 2031. However, given the economic benefit of increasing the tubular size, there may be justification or move the workover on this well forward. If the workover timing is moved forward, conducting a casing inspection log is recommended as it will defer the timing for the next casing inspection workover.

Workover Overview

[redacted]

[redacted]

Workover Timeline

Description of Operations			Number of days							
[redacted]	Hours	Cum Hours	Day	Serv R	Sup	Packer Rep	Thread Rep	N2	Slickline	Logging
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					
[redacted]										
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					
Total		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Standby Days									[redacted]	[redacted]

ANNEX 1 – [redacted]

Well Name: [redacted]

Permit #'s: [redacted]

Background and Ongoing Maintenance Considerations

1) [redacted] was originally drilled and completed in 2002.
2) 177.8 mm 38.7 kg/m L80 intermediate casing was set at an inclination of 79° in the lower portion of the tight Beekmantown A about 7 m above the top of the Beekmantown B formation. The open hole section is drilled to a total measured depth of 2622 m KB at a true vertical depth of 1509.9 m KB, with most of the horizontal length in the Beekmantown B formation. The wellbore also has a short side-track section from 2100 m KB to 2264 m KB.
3) The burst rating of the casing is 49,920 kPa, or about 2.5 times the maximum operating pressure. Consequently, even if some corrosion is evident, the casing is likely above CSA requirements for pressure integrity.
4) There are two packers isolating the formation from the annulus. The lower packer, which is set at 1466.2 m KB, is a permanent packer; and the upper packer, which is set at 1443.72 m KB, is a hydraulic set retrievable packer. An on/off tool with a 69.85 mm X profile is located immediately above the upper packer.
5) The tailpipe and tubing between the packers is 88.9 mm 13.69 kg/m L80 tubing with New NK3SB connections. The tailpipe extends to 1809.0 m KB.
6) The tubing above the packers is a tapered string with 127.0 mm 22.3 kg/m L80 Flush Seal Lock tubing down to 855 m KB, 114.3 mm 17.26 kg/m L80 New NK3SB tubing to 1433 m KB and 1 joint of 88.9 mm 13.69 kg/m L80 NK3SB tubing to the on/off tool at 1443.72 m KB.
7) The tailpipe below the lower packer is also 88.9 mm and extends to a depth of 1809.0 m KB.
8) Remedial cementing operations were conducted on this well as there was evidence of communication from the formation into the annulus. Two sets of squeeze perforations were positioned at 1347, 1360, 1420, 1430 m KB. Cement was circulated between the lower two sets of perforations and the upper two sets of perforations. The squeezes were successful to stop the gas communication.
9) Because of these squeeze perforations, annulus pressure tests are limited to 7 MPa to avoid damaging the perforations.
10) During the next workover, a hydraulic packer with a 98.65 mm bore can be set at about 1340 m so that the squeeze perforations and the annulus could be pressure tested to 22 MPa. However, if the tubing or on/off tool started to leak, then the perforations would be exposed to injection pressure without indications at surface. While the installation of the packer enables some alignment to CSA pressure testing requirements, it would require a sleeve to be placed in the interval between the existing upper packer and the new upper packer so that annulus pressure tests could be conducted. If a gas test were conducted (so that hydrostatic pressures were not involved, then the pressure test could be

increased to 20 MPa, which would be equivalent to the hydro-pressure tests to 7 MPa. A gas test to 22 MPa could also be considered as this would enable conformance to the CSA standard and only increase the pressure test on the perforations by 2 MPa. This pressure tests should be conducted every 5 years.

11) The casing was scraped in the 2005 workover and has since had inhibited water in the annulus.

Workover Overview

[redacted]

[redacted]

[redacted]

Workover Timeline

Description of Operations		Number of days							
[redacted]	Hours	Cum Hours	Day	Serv R	Sup	Packer Rep	Thread Rep	N2	Slickline	Logging
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					
[redacted]										
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					
Total		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Standby Days									[redacted]	

ANNEX 1 – [redacted]

Well Name: [redacted]

Permit #'s: [redacted]

Background and Ongoing Maintenance Considerations

1) [redacted] was originally drilled and completed in 2002.
2) 177.8 mm 38.7 kg/m L80 intermediate casing was set at an inclination of 73° in the lower portion of the tight Beekmantown A about 22 m above the top of the Beekmantown B formation. The open hole section is drilled to a total measured depth of 2522 m KB at a true vertical depth of 1512.3 m KB, with most of the horizontal length in the Beekmantown B formation. The wellbore also has two short side-track sections from 2031 m KB to 2343 m KB and from 1792.6 to 2114.0 m KB.
3) The burst rating of the casing is 49,920 kPa, or about 2.5 times the maximum operating pressure. Consequently, even if some corrosion is evident, the casing is likely above CSA requirements for pressure integrity.
4) There are two permanent packers isolating the formation from the annulus. The lower packer, which is set at 1450.7 m KB and the upper packer is set at 1448.6 m KB. The tubing is latched into the upper packer. Tailpipe with a seal assembly below the upper packer is landed into the lower packer.
5) The tailpipe below the lower packer extends to 1789.54 m KB. All of the tailpipe is 114.3 mm 18.97 kg/m L80 tubing.
6) There are three 96.85 mm Otis X nipples; one in the tubing above the packers at 1438.3 m KB, and two in the tailpipe at 1461.3m and 1471.3 m KB.
7) The tubing above the packers is a tapered string with 127.0 mm 22.3 kg/m L80 Flush Seal Lock tubing down to 909 m KB, 114.3 mm 17.26 kg/m L80 SFL tubing to the upper packer.

Workover Overview

[redacted]

[redacted]

Workover Timeline

Description of Operations		Cum	Number of days							
[redacted]	Hours	Cum Hours	Day	Serv R	Sup	Packer Rep	Thread Rep	N2	Slickline	Logging
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					
Total		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Standby Days									[redacted]	

ANNEX 1 – [redacted]

Well Name: [redacted]

Permit #'s: [redacted]

Background and Ongoing Maintenance Considerations

1) [redacted] was originally drilled in 2002 and completed in 2003.
2) 177.8 mm 38.7 kg/m L80 intermediate casing was set at 1628 m MD at an inclination of 82° in the lower portion of the tight Beekmantown A about 28.2 m above the top of the Beekmantown B formation. The open hole section is drilled to a total measured depth of 2595 m KB at a true vertical depth of 1518.7 m KB, with most of the horizontal length in the Beekmantown B formation. The wellbore also has two sidetracks that run from 1665 m MD to 2197 m MD and from 1655 m MD to 2588 m MD.
3) The burst rating of the casing is 49,920 kPa, or about 2.5 times the maximum operating pressure. Consequently, even if some corrosion is evident, the casing is likely above CSA requirements for pressure integrity.
4) There are two permanent packers isolating the formation from the annulus. The lower is set at 1504.25 m KB and the upper packer is set at 1491.4 m KB. There is no on/off tool above the upper packer.
5) The tailpipe and tubing between the packers is 114.3 mm 17.26 kg/m L80 tubing with Hunting SLSF connections.
6) The tubing above the packers is a tapered string with 127.0 mm 22.3 kg/m L80 Flush Seal Lock tubing down to 874.1 m KB, 114.3 mm 17.26 kg/m L80 SLSF tubing to 1the packers.
7) The tailpipe below the lower packer is also 114.3 mm and extends to a depth of 1652.3 m KB.
8) Remedial cementing operations were conducted on this well in 2009 as there was evidence of communication from the formation into the annulus. Two sets of squeeze perforations were positioned at 1347, 1360, 1460, 1470 m KB. Cement was circulated between the lower two sets of perforations and the upper two sets of perforations. The squeezes were successful to stop the gas communication. A casing inspection log was not run in the 2009 workover. Therefore, the next log is due in 2023.
9) Because of these squeeze perforations, annulus pressure tests are limited to 7 MPa to avoid damaging the perforations.
10) During the next workover, a hydraulic packer with a 98.65 mm bore can be set at about 1340 m so that the squeeze perforations and the annulus could be pressure tested to 22 MPa. However, if the tubing below the top packer began to leak, then the perforations would be exposed to injection pressure without indications at surface. While the installation of the packer enables some alignment to CSA pressure testing requirements, it would require a sleeve to be placed in the interval between the existing upper packer and the new upper packer so that annulus pressure tests could be conducted. If a gas test were conducted (so that hydrostatic pressures were not involved, then the pressure test could be increased to 20 MPa, which would be equivalent to the hydro-pressure

tests to 7 MPa. A gas test to 22 MPa could also be considered as this would enable conformance to the CSA standard and only increase the pressure test on the perforations by 2 MPa. This pressure tests should be conducted every five (5) years.

11) The casing was scraped in the 2009 workover and has since had inhibited water in the annulus.

Workover Overview

[redacted]

[redacted]

Workover Timeline

Description of Operations			Number of days							
[redacted]	Hours	Cum Hours	Day	Serv R	Sup	Packer Rep	Thread Rep	N2	Slickline	Logging
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					
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[redacted]										
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					
Total		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Standby Days									[redacted]	

ANNEX 1 – [redacted]

Well Name: [redacted]

Permit #'s: [redacted]

Background and Ongoing Maintenance Considerations

1) [redacted] was originally drilled and completed in 2003.
2) 244.5 mm 69.94 kg/m L80 casing was landed at 1678.3 m KB MD at an inclination of 85°.
3) A 177.8 mm 38.7 kg/m L80 intermediate liner was set at 1955 m MD at an inclination of 80° at the top of the Beekmantown B formation. The liner top is at 1242 m KB MD. A second 114.3 mm17.26 kg/m L80 liner was landed in the Beekmantown B at 2350 m KB. The burst of the 244.5 mm intermediate casing, the first 177.8 mm intermediate liner and the second 114.3 mm intermediate liners is 47,370 kPa, 49,920 kPa and 53,640 kPa, respectively. Therefore, the lowest burst rating is about 2.3 times the maximum operating pressure. Consequently, even if some corrosion is evident, the casing is likely above CSA requirements for pressure integrity.
4) However, several problems were identified in a 2017 workover as follows:
    a. A DVV valve, located at 1074.16 m KB MD did not seem to be full drift.
    b. Extra weight was needed on logging tools to get into the wellbore with the HRVertilog. Still could only get down to 1130 m KB.
    c. Could not get past 1118 m KB with 244.5 mm casing scraper. Seemed to be cement stringers in casing.
    d. Could run 177.8 mm scraper down to packer at 1452 m KB.
    e. After pulling out, could not run a 177.8 mm packer past the DVV tool.
    f. Had trouble getting into intermediate liner top at 1242 m KB with 146 mm OD overshot, a cut lip is recommended
    g. There may be residual cement between the DVV tool and the intermediate liner top.
5) Because of the problems getting through the DVV tool, a 244.5 mm x 88.9 mm hydraulic packer was landed above the DVV tool at 1042.89 m KB. Originally, straddle packers were programed to be positioned just above and below the liner top.
6) The casing inspection log run in 2017 did not show evidence of corrosion. The next casing inspection log is not due until 2037. When this work is done, a camera should be run to better understand the wellbore problems. Other technologies may also be available.
7) A detailed review of the workover history should be conducted before programing the next operations to ensure appropriate precautions are in place so that planning around wellbore problems is addressed.
8) New technologies may be available by 2037 that may reduce the need to trip tubulars (such as improved through-tubing casing inspection logging). Currently, these technologies are not considered to be reliable.

Workover Overview

[redacted]

[redacted]

Workover Timeline

Description of Operations		Cum Hours	Number of days							
[redacted]	Hours		Day	Serv R	Sup	Packer Rep	Thread Rep	N2	Slickline	Logging
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				[redacted]	
[redacted]										
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			
[redacted]										
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					
Total		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Standby Days									[redacted]	

ANNEX 1 – [redacted]

Well Name: [redacted]

Permit #'s: [redacted]

Background and Ongoing Maintenance Considerations

1) [redacted] was originally drilled and completed in 2004.
2) 177.8 mm 38.7 kg/m L80 intermediate casing/liner was set at 2124 m KB MD (1506 m KB TVD) at an inclination of 84° in the top of the Beekmantown B.
3) The 177.8 mm liner top is at 455.2 m KB and a 177.8 mm tie-back liner is landed in the tie-back receptacle and tied back to surface.
4) There is an external casing packer on the tie-back liner at 451 m KB.
5) The open hole section is drilled to a total measured depth of 3047 m KB at a true vertical depth of 1539.2 m KB, with all of the horizontal length in the Beekmantown B formation. The wellbore also has two short side-track sections from 2212 m KB to 2664 m KB and from 2150 to 2652 m KB MD.
6) The burst rating of the casing is 49,920 kPa, or about 2.5 times the maximum operating pressure. Consequently, even if some corrosion is evident, the casing is likely above CSA requirements for pressure integrity.
7) There are two permanent packers isolating the formation from the annulus. The lower packer, which is set at 2036.14 m KB and the upper packer is set at 1207.96 m KB. The tubing is latched into the upper packer. Tailpipe with a seal assembly below the upper packer is landed into the lower packer.
8) The tailpipe below the lower packer extends to 2138.44 m KB. All of the tailpipe is 114.3 mm 17.26 kg/m L80 tubing.
9) There are four 96.85 mm Otis X nipples; one in the tubing above the packers at 1196.15 m KB, one between the packers at 1223.09 m KB and two in the tailpipe at 2051.26 m and 2065.79 m KB.
10) The tubing above the packers is a tapered string with 127.0 mm 22.3 kg/m L80 Flush Seal Lock tubing down to 1073.9 m KB, 114.3 mm 17.26 kg/m L80 SFL tubing to the upper packer.
11) The 177.8 mm casing system should be pressure tested to 22 MPa down to the top packer. Because the top packer is a permanent packer, logging operations below the packer cannot be conducted unless the packer is cut out and later replaced. Additionally, there is no sliding sleeve between the packers so the casing cannot be pressure tested between packers. Given the high strength of the casing between the packers, it is not recommended to cut the upper packer out unless there is evidence of a mechanical integrity failure. The formation strength below the upper packer is higher than injection pressures and does not present a risk of loss of gas if the tubulars at this depth were to fail. However, the upper wellbore should be conventionally monitored.
12) The surface casing has a burst rating of 39,640 kPa.

Workover Overview

[redacted]

[redacted]

Workover Timeline

Description of Operations		Cum	Number of days							
[redacted]	Hours	Hours	Day	Serv R	Sup	Packer Rep	Thread Rep	N2	Slickline	Logging
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					
[redacted]										
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			
[redacted]										
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
[redacted]										
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			
[redacted]										
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			
[redacted]										
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					
Total		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Standby Days									[redacted]	

ANNEX 2 – DETAILED COST ESTIMATE

Project Name: St. Flavien Workovers
Location: St. Flavien
AFE No.: 1 Cost Centre:

DESCRIPTION
Cost estimate to complete workover schedule and regain compliance with CSA standard.

Code		INTANGIBLE COMPLETION COST	Mob/ Demob/ Repairs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Total	Mobilization Costs (7 Mob's)	Site Costs	Total Cost
930	058	Rig Move in/out (includes Camp move)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
930	063	Service rig - Daywork		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]
930	064	Mud and Chemicals		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]
930	068	Crew travel, Subsistence and camp																		-	-	-
930	069	Water & Water hauling		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]
930	070	Boiler																		-	-	-
930	071	Communications																		-	-	-
930	072	Equipment Rentals - BOP Equipment			[redacted]				[redacted]								[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]
930	072	Equipment Rentals Drill Pipe and Collars																		-	-	-
930	072	Equipment Rentals - Power Swivel																		-	-	-
930	072	Equipment Rentals - Power Plant																		-	-	-
930	072	Equipment Rentals - Other		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]
930	074	Fuel and Lubricants																		-	-	-
930	081	Wellsite supervision	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
930	083	Engineering services		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]
930	090	Trucking and Hauling	[redacted]		[redacted]				[redacted]								[redacted]		[redacted]	[redacted]	[redacted]	[redacted]
930	091	Tank Truck and Fluid Hauling																		-	-	-
930	094	Fluid Disposal (Vacuum Truck)																		-	-	-
930	098	Fishing Services			[redacted]														[redacted]	-	[redacted]	[redacted]
930	100	Casedhole Logging & Perforating		[redacted]		[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]
930	102	Safety services																		-	-	-
930	104	Environmental services																		-	-	-
930	109	Wireline Services & Recorders		[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]
930	110	Pickup/Laydown/Torque Services											[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]
930	111	Thread Supervision Services											[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]
930	112	Coil Tubing / N2 Services											[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]
930	115	Snubbing Equipment																		-	-	-
930	126	Packer Equipment Supervision		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]
930	139	Cement & Services - Primary or Remedial																		-	-	-
		Subtotal:	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Code		TANGIBLE COMPLETION																				
940	054	Wellhead, Assembly and Installation								[redacted]			[redacted]						[redacted]	-	[redacted]	[redacted]
940	105	Production Tubing											[redacted]	[redacted]		[redacted]			[redacted]	-	[redacted]	[redacted]
940	105	Production Casing																		-	-	-
930	108	Downhole equipment (Except BH pumps)												[redacted]		[redacted]			[redacted]	-	[redacted]	[redacted]
		Subtotal:											[redacted]						[redacted]	-	[redacted]	[redacted]
Code		GENERAL																				
930	130	Miscellaneous																		-	-	-
930	199	Contingency (25%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
930	500	Non-Op ICC																		-	-	-
930	129	Overhead 3/2/1 or ____________																		-	-	-
		Subtotal:	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		TOTAL	329,000	387,100	376,850	158,825	228,675	228,675	286,355	95,075	226,475	226,475	794,599	661,820	517,135	660,070	666,899	558,974	6,403,000	2,303,000	6,074,000	8,377,000

Prepared by: Todd Wilson
Date: 27-Jul-21