McMoRan Oil and Gas
OCS-G 26013 Well A1
South Marsh Island Block 230
"Davy Jones" Prospect
Summary Well Temporarily Abandonment (TA) Procedure
May 22, 2014

SUMMARY:

McMoRan Oil and Gas (MMR) is seeking BSEE approval to temporarily abandon (TA) the OCS-G 26013 #A1 ST01 "Davy Jones #1" (DJ1) well.

With BSEE approval, the forward TA plan is to rig up 15K coiled tubing equipment to set a cement plug at least 300 ft long with the bottom of the plug no more than 100 ft above the perforated interval, as per 30 CFR 250.1721 (b) and 30 CFR 250.1715 (a) (3) (iii) (C). The well will then be displaced with kill weight fluid (18.5 ppg low toxicity mineral oil mud) from above the cement plug to 16,350 ft (top of the liner/ production packer).

This will be followed by setting a 2.313" plug on eline in the nipple profile above the production packer, as a mechanical barrier as per 30 CFR 250.1715 (a) (11). The tubing will be punched above the packer at 16,290 ft and kill weight fluid circulated in the tubing and tubing-casing-annulus. The dual Surface Controlled Sub-Surface Safety Valves will be closed and a back pressure valve set in the tubing hanger. The 25K Production Tree will be removed and replaced with a 25K BOPE.

The tubing will be cut above the packer and tubing pulled out of hole. A second cement plug 200 ft long will be set inside the 7" production tieback casing, 500 ft above the packer, as per 30 CFR 250.1721 (c). A pressure test will be performed at 1,000 psi on the 2nd cement plug, as per 30 CFR 250.1715 (b) (2). Kill weight mud will remain above the cement plug. A third cement plug 500 ft will be placed inside the 7" tieback casing, with the base of the plug at 1,000' from surface, as per 30 CFR 250.1721 (d).

Sea water will be left above the 500 ft cement plug inside the tieback casing. A 25K dry hole tree will be installed prior to rig demobilization.

The three cement plugs, a 2.313" plug/production packer and dry hole tree provide five independent well control barriers for the well TA; see Well Schematic (Proposed), page 10.

PERFORATION INTERVALS:

Sand	Perfs (MD)	Perfs (TVD)	BHP (psi)	BHT (°F)	MASP (psi)
Wilcox F	28,325'-28,354'	28,228'-256'	26,500		22,500
	28,364'-28,374'	28,266'-276'			
	28,384'-28,422'	28,285'-322'		454	
Wilcox D	27,830'-27,872	27,613'-655'			
Wilcox C	27,530'-27,582'	27,454'-506'			
Wilcox B	27,380'-27,424'	27,310'-354'			
	27,434'-27,438'	27,364'-368'			
	27,448'-27,458'	27,377'-387'			

DETAILS OF TA OPERATIONS:

1. Rig up (RU) H_2S equipment on Mobile Offshore Drilling Unit (MODU). Mobilize MODU to location, jack-up, and skid out over well.

   NOTE*:*

   - Confirm 30K kill pump system installed on the DJ#1 platform is functional and rigged up to the 25K tree.

2. Conduct Job Safety Assessment (JSA). Review temporary abandonment (TA) operations with rig crew, service company personnel, and other pertinent parties. Begin TA operations.

3. Verify all the valves on 2⁹⁄₁₆" 25K production tree are closed. Record wellhead pressure in the 'A', 'B', and 'C' annuli. RU equipment to bleed off pressure from the well as required.

4. On the 2⁹⁄₁₆" 25K production tree, slowly open master surface safety valve (MSSV), then 2⁹⁄₁₆" 25K manual crown valve (MCV) and record the pressure above the back-pressure valve (BPV) in the tubing hanger.

5. RU 2⁹⁄₁₆" 25K manual working valve (MWV) on top of the MCV.

6. RU 3⁹⁄₁₆" 30K wireline pressure control equipment (WLPCE) on top of the MWV.

- *See Stack up Schematic DJ-CO-DG-0004*

7. Pressure test WLPCE to 250 psi low, and 23,000 psi high.

8. Run-in-hole (RIH) with slick-line and equalize pressure across the back-pressure valve (BPV) in the tubing hanger.

9. Pull out of hole (POOH) with the BPV. Lay down (LD) BPV.

10. Monitor well pressure in the tubing.

11. Pick up (PU) GS pulling tool. Make up (MU) 30K WLPCE lubricator. RIH with pulling tool to engage the 2.375" slickline plug. Pressure up to equalize across the plug in the 2.375" nipple located above the dual surface controlled subsurface safety valves (SCSSVs).

12. POOH and LD 2.375" slickline plug.

13. Monitor well pressure in the tubing. Close 2$\frac{9}{16}$" 25K MWV.

14. Equalize pressure in the well above the dual SCSSVs. Open the dual SCSSVs. If needed, MU 30K WLPCE lubricator and make a dummy run with slickline to make sure dual SCSSVs are open.

15. Monitor pressure in the tubing.

16. Bleed pressure from the tubing. Once wellhead pressure declines, close dual SCSSVs. Close 2$\frac{9}{16}$" 25K MCV and MSSV.

17. Rig down (RD) 30K WLPCE. RU for coiled tubing (CT) well intervention operations.

18. RU 13$\frac{5}{8}$" 25K BOP blind shear ram (BSR) on top of the 2$\frac{9}{16}$" 25K production tree MCV. RU wedgelock control system on the 25K BOP.

19. Pressure test the 13$\frac{5}{8}$" 25K BOP BSR to 250 psi and 23,000 psi; record time to close the BSR.

20. RU a 2$\frac{9}{16}$" 25K MWV on top of the 13$\frac{5}{8}$" 25K BSR. Pressure test the 25K MWV to 250 psi and 23,000 psi against the 2$\frac{9}{16}$" 25K production tree MCV.

21. Using CT BOP test stump, pressure test the blind rams of the 5$\frac{1}{8}$" 15K CT Quad BOP and blind/shear rams of the 5$\frac{1}{8}$" 15K CT Combi BOP to 250 psi and 15,000

psi for 5 min. Install 1¾” test bar and pressure test the pipe rams of the 5⅛” 15K CT Quad BOP and slip/pipe rams of the 5⅛” 15K CT Combi BOP to 250 psi and 15,000 psi for 5 min.

22. RU 4¹⁄₁₆” 15K risers on top of the 2⁹⁄₁₆” 25K MWV to the rig floor.

23. RU 4¹⁄₁₆” 15K Manual Valve on top of the riser at the rig floor level.

24. Nipple Up (NU) 5⅛” 15K CT BOPs, 15K Quick Connect and Quick Test Sub, dual 15K strippers, and coiled tubing unit (CTU) on top of the 4¹⁄₁₆” 15K Manual Valve.

    - *See Stack up Schematic DJ-CO-DG-0005*

25. Install 1.81” 0.134” WT dimple-on coil connector on 1¾” OD CT. Pull the connector to 10,000 lbs, and pressure test to 5,000 psi.

    Note:

    - Monitor pressure on the 2⁹⁄₁₆” 25K tree and wellhead pressure in the ‘A’, ‘B’, and ‘C’ annuli. Multiple alarms will be set at the planned operational limit.

    - Monitor liquid and gas returns.

    - In an emergency where the wellhead pressure reaches 12,000 psi (80% of the operational limit for 15K coiled tubing system), the 1¾” coil tubing (CT) will be sheared using the 13⅝” 25K BOP blind shear ram. The CT will be picked up and the 2⁹⁄₁₆” 25K MWV closed. Then, the 5⅛” 15K blind/shear rams on the coiled tubing Combi BOP and 5⅛” 15K blind rams on the coiled tubing Quad BOP will be closed. Well will be secured.

26. Make up (MU) 1.81” OD CT BHA with wash nozzle, 1.81” OD dual flapper check valve and 1.81” OD weight bars.

27. Pressure test the CT system to 250 psi and 15,000 psi for 10 min.

28. Open 2⁹⁄₁₆” 25K production tree MSSV and 2⁹⁄₁₆” 25K MCV. Equalize and open dual SCSSVs. Monitor pressure in the 3½” production tubing. If needed, bleed off wellbore pressure to below 10,000 psi.

29. Open 2⁹⁄₁₆” 25K MWV. Verify all valves are open prior to RIH with CT.

30. RIH with 1¾" CT to 27,280 ft (100 ft above the top perforations) while displacing 10.4 ppg fluid in the wellbore with 14.0 ppg calcium bromide ($CaBr_2$).

31. Pump cement down the coiled tubing and POOH while laying at least 300 ft of cement in the 5" liner with the bottom of the cement plug at 27,280 ft.

32. Circulate bottoms up above the cement plug with 14.0 ppg $CaBr_2$, while holding back pressure. POOH while maintaining back pressure. Wait on cement.

33. RIH with CT near the top of the cement plug. Displace liner with 18.5 ppg LTMO mud from the top of the cement plug to 16,350 ft.

34. POOH with 1¾" CT. Close the dual SCSSVs, 2⁹⁄₁₆" 25K production tree MSSV and 25K MCV, and 25K MWV.

35. RD CT equipment. Monitor well.

36. RD 2⁹⁄₁₆" 25K MWV. RD 13⅝" 25K BOP BSR from 2⁹⁄₁₆" 25K production tree.

37. RU a 2⁹⁄₁₆" 25K MWV on top of the on top of the 2⁹⁄₁₆" 25K production tree. RU 3⁹⁄₁₆" 30K WLPCE on top of the 2⁹⁄₁₆" 25K MWV. Pressure test WLPCE to 250 psi low, and 23,000 psi high against the 25K MWV.

    - *See Stack up Schematic DJ-CO-DG-0010*

38. Open 2⁹⁄₁₆" 25K production tree MSSV and 25K MCV. Equalize and open dual SCSSVs. Monitor pressure in the 3½" production tubing.

39. Open 2⁹⁄₁₆" 25K MWV. RIH with e-line and set 2.313" plug in the nipple profile in the tubing at 16,288 ft, above the production packer. POOH. RIH and set prong in the 2.313" plug. POOH.

40. RIH with tubing punch perforating charges on eline and shoot circulating holes in 3½" tubing above the production packer while holding pressure on annulus. POOH tubing puncher.

41. Circulate tubing and casing-tubing-annulus with 18.5 ppg LTMO mud while holding back-pressure on the returns.

42. Close the dual SCSSVs.

43. RIH with eline and install BPV with prong (2-way check) in tubing hanger. POOH. Monitor well.

44. Close 2⁹⁄₁₆" 25K production tree MSSV and 25K MCV.

45. RD 3⁹⁄₁₆" 30K WLPCE.

46. Monitor well.

47. ND 2⁹⁄₁₆" 25K Production Tree.

48. NU 13⅝" 25K x 11" 25K double studded adapter flange (DSA) on top of 11" 25K tubing head. NU 13⅝" 25K BOPE on top of the DSA. Test BOP to 250 psi low and 23,000 psi high (10K annular to 250-7,000 psi).

NOTE*:*

- <u>Top to bottom BOP rams</u>: Inverted blind/shear rams, 3½" pipe, blind/shear, 2⅞" pipe, 3½" pipe
    - *See Stack up Schematic DJ-CO-DG-0007*
- Subsequent BOP pressure tests will be conducted every 7 days or less and BOP, including wedgelock; function tests will be conducted every 7 days or less.
- RU 30K kill pump and 2⁹⁄₁₆" 25K choke and kill manifold to the 13⅝" 25K BOPE system.
- 30K kill pump to remain rigged up and operational throughout the TA operations.

49. RIH with tubing hanger torque tool on 3½" 15.48# C-22HS Vam TOP landing joint. Release 25K mandrel tubing hanger. POOH.

50. RIH with tubing hanger running tool on 3½" 15.48# C-22HS Vam TOP landing joint. Engage 11" 25K mandrel tubing hanger and pull 3½" tubing in tension.

51. RU 15K FOSV on top of the landing joint. RU 3¹⁄₁₆" 15K WLPCE on top of the FOSV.

- *See Stack up Schematic DJ-CO-DG-0019*

52. Pressure test WLPCE to 250 psi low, and 15,000 psi high against the 15K FOSV.

53. Monitor well. RIH and pull BPV with prong (2-way check).

54. Equalize and open the dual SCSSVs.

55. RIH with tubing explosive cutter on e-line and cut 3½" tubing above the packer, while maintaining tension in the tubing.

56. POOH with eline and tubing cutter. Monitor well. RD 3$\frac{1}{16}$" 15K WLPCE.

57. POOH and LD 11" 25K mandrel tubing hanger, dual SCSSVs and control lines, and 3½" production tubing.

58. RIH and set storm packer with tail pipe. Change BOP rams configuration, from top to bottom, with rams inverted blind/shear rams, 2⅞" pipe, blind/shear, 2⅞" pipe, 3½" pipe, to run 2⅞" workstring. Test BOP to 250 psi low and 23,000 psi high (10K annular to 250 psi and 7,000 psi). Pull storm packer.

    - *See Stack up Schematic DJ-CO-DG-0009*

59. PU and RIH with 2⅞" workstring (NC-26, X-95, 0.362" wall, 10.4 lb/ft nominal weight) and set a 200 ft cement plug with the base of cement plug 500 ft above the packer at 16,290 ft. Wait for cement to set. POOH to 1,000 ft while LD workstring.

60. Perform positive pressure test to 1,000 psi.

61. Set 500 ft of cement plug from 500 ft to 1,000 ft. Wait for cement to set. POOH to 500 ft while LD workstring

62. Displace well with seawater to surface. POOH and LD workstring.

63. Monitor well. RD 13⅝" 25K BOPE.

64. RD 13⅝" tubing spool. RU 13⅝" 15K x 2$\frac{9}{16}$" 25K adapter on top of the 13⅝" 15K flange.

65. Install 2$\frac{9}{16}$" 25K dry hole tree (DHT). Pressure test DHT to 1,000 psi. Record pressure on DHT. Close all valves on DHT and secure well (see note below).

- *See Stack up Schematic DJ-CO-DG-0008*

66. Demobilize MODU.

67. Seek BSEE approval for subsequent operations at OCS-G 26013 #1 ST01 “Davy Jones #1” well.

68. File EOWR with BSEE Lafayette District.

Note:

- The well will have 18.5 ppg LTMO mud in the liner and in the tieback casing, and in between the cements plugs set.

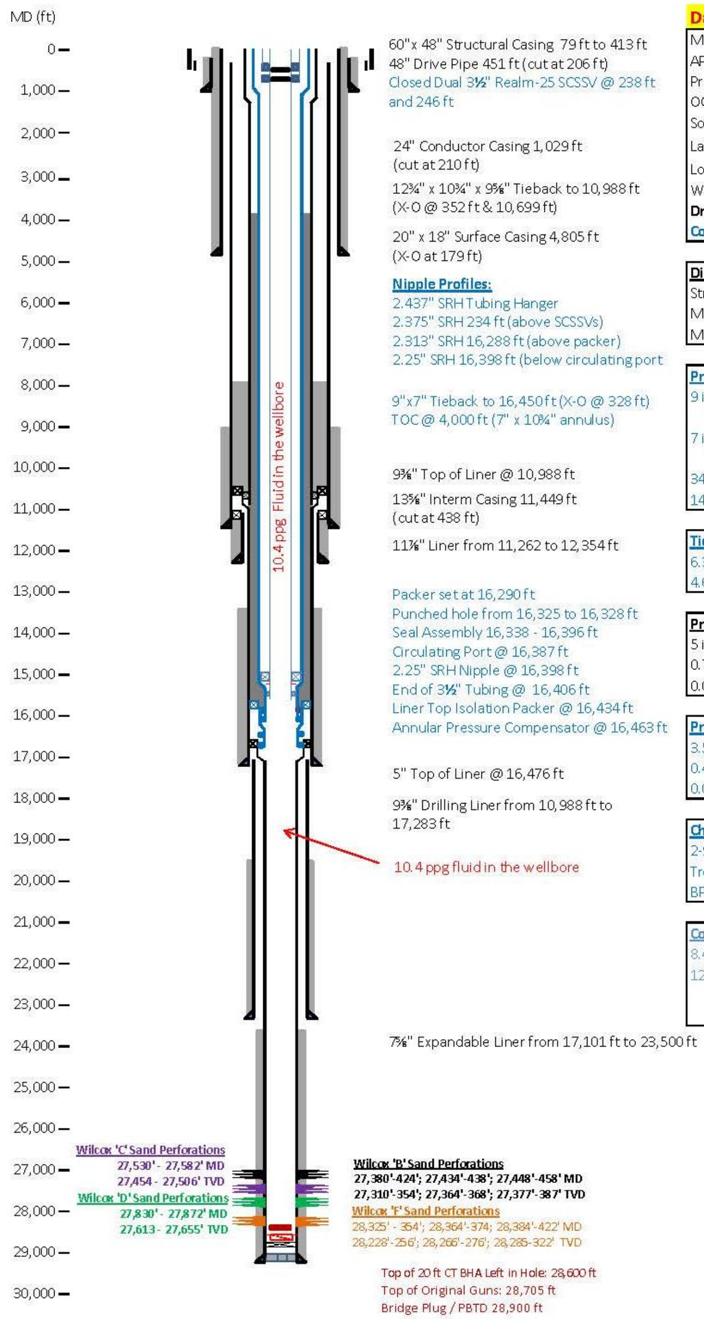
- After the TA operations, pressure on Wellhead/‘A’, ‘B’ and ‘C’ annuli will be continuously monitored on platform logic control (PLC) using the pressure transducer installed in the respective annuli, when persons are onboard the DJ#1 production platform.

- In case personnel are not living on the DJ#1 platform, pressure gauge data on wellhead/’A’, ‘B’ and ‘C’ annuli will be recorded once a month by visiting the platform.

Prepared by: Nigel Alvares, Consultant, Coiled Tubing Advisor
Tom Funchess, P.E., Consultant, Sr. Completion Engineer
Naval Goel, Consultant, Engineering Advisor
David Law, Consultant, Well Control Advisor
Richard A. Sukup, P.E., Consultant, Sr. Advisor

Reviewed by: David B. Lewis, P.E., Consultant, Well Delivery Manager

Approved by: William R. Richey, Sr. Vice-President-McMoRan Oil & Gas



Davy Jones 1

McMoRan Oil & Gas LLC
API #: 17-707-40868-01
Proposed Completion Davy Jones 1
OCS-G 26013 # A1
South Marsh Island Block 230
Latitude: 29° 20' 39.530" N (NAD 27)
Longitude: 92° 03' 13.686" W
Water Depth 19 ft
Drilled: 3/10 Rowan Mississippi (240-C JU); RKB 129'
Completion/ReWorkover: Rowan EXL III Jackup; RKB 129'

Directional Data:
Straight to ~24,600 ft
Max. Inclination 14.1° at 26,100 ft
Max. DLS 10.5° at 23,500 ft

Production Tieback:
9 in. 110.4 ppf 15Cr125 VAM HP to 325 ft
1.35 in. Wall, 6.300 in. ID, 6.175 in. Drift
7 in. 74.4 ppf 15Cr125 JFE LION HW from 325 ft to 16,455 ft
1.200 in. Wall, 4.600 in. ID, 4.475 in. Drift
343 bbl Capacity with no tubing to 16,420 ft
147 bbl Annular Capacity with 3½" tubing to PBR @ 16,349 ft

Tieback Tubing Annulus:
6.3" x 4.6" = 0.0267 BPF; 6.8 bbl Cap. (70 ft to 325 ft)
4.6" x 3.5" = 0.00866 BPF; 139 bbl Cap. (325 ft to 16,349 ft)

Production Liner:
5 in. 34 ppf Q-125 HWST SC70 from 16,476 ft to 29,091 ft
0.75 in. Wall, 3.500 in. ID, 3.375 in. Drift
0.0119 BPF; 149 bbl Capacity from 16,476 ft to 28,900 ft PBTD

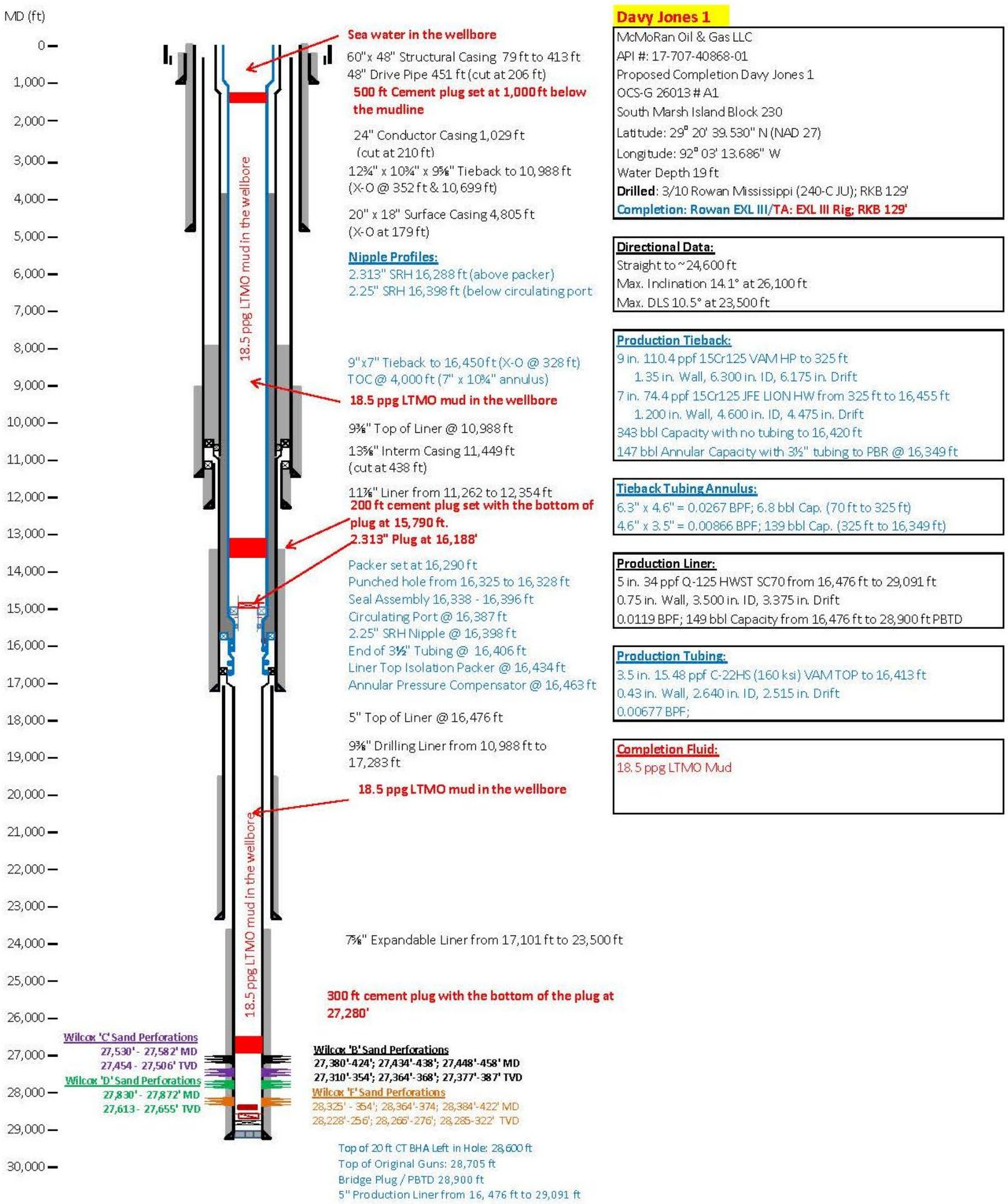
Production Tubing:
3.5 in. 15.48 ppf C-22HS (160 ksi) VAM TOP to 16,413 ft
0.43 in. Wall, 2.640 in. ID, 2.515 in. Drift
0.00677 BPF; 111 bbl Capacity to 16,349 ft

Christmas Tree:
2-9/16" 25M (run & wings)
Tree Top Flange: 2-9/16" 30M
BPV Profile: 2.437" SRH

Completion/Packer Fluid:
8.4 ppg Inhibited Fresh Water Packer Fluid
12.0 ppg Sodium Bromide from 28,600 ft to Surface

Well Schematic (Initial)

McMoRan SM230 A1 "Davy Jones"
Summary Well TA Operations Procedure
May 22, 2014



Well Schematic (Proposed)