Appendix F  Lock-Down Sleeve Decision

After the production casing has been installed in the well and cemented in place, the operator may elect to run a lock-down sleeve. A lock-down sleeve locks the casing hanger to the wellhead housing, which prevents upward movement of the casing system and typically is installed prior to completion operations. The lock-down sleeve on Macondo was positioned inside the well on top of the 9-7/8-in. casing hanger and latches into the 18-3/4-in. wellhead housing, thus securing the casing from potentially lifting upwards after it is landed.

Lock-Down Sleeve Procedures

Initially, BP’s temporary abandonment procedure (as proposed on April 12) specified setting the lock-down sleeve before commencing temporary abandonment operations. Figure 1 represents a typical lock-down sleeve. BP modified the procedure twice and then submitted to the Minerals Management Service (MMS) an Application for Permit to Modify on April 16. The modified procedure directed that the lock-down sleeve be set last, after displacing the kill line to seawater, conducting a negative pressure test and setting a surface cement plug for the temporary abandonment.
Appendix F  Lock-Down Sleeve Decision

Changing the sequence in which the sleeve would be set from first to last eliminated the risk of damaging the internal sealing areas of the lock-down sleeve while running drill pipe into the well to set the surface cement plug. However, setting the lock-down sleeve last impacted other well activities during the abandonment phase of the well and increased other risks.

The lock-down sleeve is set in position with a running tool by applying weight. To set the lock-down sleeve, Dril-Quip recommended running 100,000 lb. of weight below the running tool. The weight below the running tool is known as the tailpipe. To achieve the 100,000 lb., there had to be enough space left below the wellhead and above the top of the surface cement plug, which under the final plan would be set in place prior to the lock-down sleeve being installed. Alternatively, Dril-Quip stated in their manual that weight above the running tool could be substituted for weight below the running tool.

BP’s lock-down sleeve running procedure, as revised on April 13, called for assembling 24 joints of 5-1/2-in heavyweight drill pipe (HWDP) and 6-1/2-in. drill collars as a tailpipe section to achieve this required weight. The tailpipe would have been run to approximately 1,350 ft. below the wellhead utilizing this configuration.

In an April 15 version of the 9-7/8-in. x 7-in. casing program, BP specified that six joints of 6-1/2-in. collars; 28 joints of 5-1/2 in. HWDP; and about 36 joints of 5-1/2 in., 21.9-pound-per-foot drill pipe (standard drill pipe) would be used to provide the tailpipe weight. As standard drill pipe provides less weight than heavyweight drill pipe, this tailpipe would have been run to approximately 2,700 ft. below the wellhead.

BP’s final abandonment procedure provided to the drill crew on the morning of April 20, 2010, noted that the cement plug would be set at 8,367 ft. (3,300 ft. below the wellhead), or 600 ft. deeper than the 2,700 ft. of tailpipe in the casing program of April 15. The April 15 version had a tailpipe weight that was much closer to the required amount to set the lock-down sleeve per Dril-Quip procedures. It is unknown why this depth was changed from the previous procedure. The investigation team noted that the 5-1/2-in. standard drill pipe was available in the derrick while the HWDP and drill collars were on the rig’s pipe deck. Picking up the HWDP and drill collars from the deck to the drill floor could be performed offline, meaning the operation could be conducted at the same time as other main operations and not directly impact the rig time and costs. However, at the end of operations, the pipe would need to be laid back on the deck, which could not be done at the same time that the riser and BOP stack was being pulled, and would thus increase operational time and cost.

BP’s decision to set the cement plug deeper, at 8,367 ft., was not critical until BP decided to change the sequence of its abandonment procedures and set its final abandonment cement plug in seawater to minimize contamination of cement with the drilling mud. BP had it classified as a “surface plug.” This waiver likely saved 8 to 12 hours of rig time that would have been necessary to wait for the cement to harden prior to testing the plug, as there were no MMS weight testing or pressure testing requirements for plugs classified as surface plugs.

There is no evidence that BP conducted any formal risk assessment to evaluate the increased risks associated with removing additional amounts of heavy mud in the well and replacing it with lighter seawater before the negative test was performed. Also, no management of change or other risk assessment documents appear to have been prepared.

Casing Hanger Load Summary

The investigation evaluated the potential for the production casing hanger to be unseated, thereby enabling a flow path for hydrocarbons up the production casing annulus. The tension loads experienced by the casing hanger were evaluated by Stress Engineering Services, the findings of which are summarized in Appendix B. The known and anticipated loads on the production casing and casing hanger revealed that the casing hanger likely had some positive tension load throughout the incident, but this was dependent upon the annulus pressure which, if sufficiently high, could have moved the tension load to neutral or slightly negative.

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A Since the wellhead and casing temperatures experienced during the time the well was flowing can only be roughly estimated, any annulus pressure due to the thermal effects likewise would be only rough estimates. It is theoretically possible that the casing hanger and seal assembly could have experienced enough of an uplift force from the combination of thermal effects on the casing and annulus pressure below the casing hanger to temporarily unseat the seal assembly. This would have relieved the annulus pressure and the casing hanger and seal assembly would have re-seated in the wellhead.
After successfully killing the Macondo well, the seal assembly and casing hanger were found to be in the correct position when located with the Dril-Quip Lead Impression Tool (LIT) during the course of the abandonment operations. The 9-7/8-in. casing was perforated, and there was no indication of pressure or gas in the casing annulus.

Both the seal assembly and casing hanger were recovered prior to permanently abandoning the Macondo well. Photographs of the casing hanger and seal assembly show the erosion effects of the well flow path to be from the interior of the casing and not from the casing annulus.

During the Macondo abandonment operations, a 1-5/8-in. brass setting ball was recovered from a section of the marine riser. It is believed this was the ball utilized to activate the Allamont Diverter Test Device and Diverter Sub. Once activated, the ball will drop down hole to the float collar. The presence of this ball in the riser section confirms that the flow path must have been from the bottom of the casing, rather than up the annulus.
1. See Section 3.2, Temporary Abandonment.


4. Ibid.

5. 7” x 9 7/8” Interval, April 15, 2010, BP-HZN-CEC017621, 30.

6. BP-HZN-CEC020165, Email from Brian Morel to Robert Kaluza, et al.

7. 7” x 9 7/8” Interval, April 15, 2010, BP-HZN-CEC017621, 30.

8. Transocean Deepwater Horizon Morning Report, April 18, 2010, TO-DHTF-00005081.


10. See Appendix B.

