APPENDICES

LAST UPDATE- 2011

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APPENDIX 1

TESTING PROCEDURE FOR PSH AND PSL 1.

Close isolating valve on pressure sensing connection.

2. Apply pressure to sensor with hydraulic pump, high pressure gas or nitrogen, and record high sensor trip pressure.

3. If sensor is installed in series with the high sensor upstream from the low sensor, bleed pressure to reset the high sensor. Bleed pressure from sensors and record low sensor trip pressure.

4. Adjust sensor, if required, to provide proper set pressure. 5.

Open sensor isolating valve.

APPENDIX 2

TESTING PROCEDURE FOR LSH AND LSL

INSTALLED INTERNALLY

1. Manually control vessel dump valve to raise liquid level to high level trip point while observing liquid level in gage glass.

2. Manually control vessel dump valve to lower liquid level to low level trip point while observing liquid level in gage glass.

INSTALLED IN OUTSIDE CAGES

1. Close isolating valve(s) on float cage(s).

2. Fill cage(s) with liquid to high level trip point.

3. Drain cage(s) to low level trip point.

4. Open isolating valve(s) on cage(s).

APPENDIX 3

TESTING PROCEDURE FOR TSH AND TSL

TEMPERATURE BATH METHOD

1. Remove temperature sensing probe.

2. Place a thermometer in the hot bath.

3. Insert temperature sensing probe in the bath and raise temperature of bath until the controller trips.

4. Verify that this temperature is no higher than the operator specified maximum temperature for the process.

5. Insert temperature sensing probe in the bath and lower temperature of bath until the controller trips.

6. Verify that this temperature is no lower than the operator specified minimum temperature for the process.

7. Reinstall temperature sensing probe.

OPERATION TEST METHOD

Test in accordance with the manufacturer's operating manual.

Note: Because of the destructive tendencies, Eutectic type temperature devices are not to be tested.

APPENDIX 4

TESTING PROCEDURE FOR PSV

1. Remove lock or seal and close inlet isolating block valve. (Not required for PSV's isolated by reverse buckling rupture disc or check valve or pilot operated PSV's.)

2. Apply pressure through test connection with nitrogen, high pressure gas or hydraulic pump, and record pressure at which the relief valve or pilot starts to relieve.

3. The safety valve or pilot should continue relieving down to reset pressure. Hold test connection intact until the pressure stops dropping to ensure that valve has reset.

4. Open inlet isolating block valve and lock or seal.

APPENDIX 5

TESTING PROCEDURE FOR FSV

1. Close upstream valve and associated header valves.

2. Open bleeder valve and bleed pressure from flowline between closed valves.

3. Close bleeder valves.

4. Open appropriate header valve.

5. Open bleeder valve.

6. Check bleed valve for backflow. If there is any continuous backflow, measure the leakage rate.

7. Close bleeder valve and open upstream valve.

MAXIMUM ALLOWABLE LEAKAGE

Gas - 5 cubic feet per minute
Liquid - 200 cubic centimeters per minute

APPENDIX 6

TESTING PROCEDURE FOR BSL

PILOT FLAME-OUT CONTROL

1. Light pilot

2. Block fuel supply to main burner.

3. Shut off fuel supply to pilot and check BSL for detection.

BURNER FLAME-OUT CONTROL

1. Light main burner.

2. Block fuel supply to pilot.

3. Shut off fuel supply to main burner and check BSL for detection.

APPENDIX 7
TESTING PROCEDURE FOR SDV

1. Bleed pressure off of the actuator and allow valve to reach the 3/4 closed position.

2. Return supply pressure to the actuator.

APPENDIX 8

TESTING PROCEDURE FOR SSV/USV

1. Close valve to be tested.

2. Position valve(s) as required to permit pressure to be bleed off downstream of the SSV/USV.

3. With pressure on upstream side of SSV/USV, open bleed valve downstream of test valve and check for flow.

4. Close bleed valve.

5. Return SSV/USV to service.

MAXIMUM ALLOWABLE LEAKAGE

No fluid flow allowed.

APPENDIX 9

TESTING PROCEDURE FOR SCSSV, TUBING PLUG, AND INJECTION VALVE

Note: All these test methods shall meet or exceed the requirements set forth in the current incorporated edition of API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems. The leakage rates are those set forth in Subpart H or in the approved DWOPs.

SURFACE MAXIMUM ALLOWABLE LEAKAGE RATE

Gas - 5 cubic feet per minute Liquid - 200 cubic centimeters per minute

SUBSEA MAXIMUN ALLOWABLE LEAKAGE RATE

Gas - 15 cubic feet per minute
Liquid - 400 cubic centimeters per minute

Note:

1. The listed testing procedures are for wells that **<u>do not produce H_2S.</u>** For wells that produce H_2S, pressure must be bled into a closed system, such as pressure vessels or a flare system, using H_2S resistant material.
2. For SCSSV testing:
   A. Use either Method A for normal wells for gas.

Method A:

1. Shut-in the well at the wellhead.
2. Wait an appropriate period of time and record SITP.
3. Bleed SCSSV hydraulic control line pressure to zero to shut-in SCSSV. Then observe pressure for build up. (Not applicable for subsea wells).
4. Bleed surface pressure sufficiently to establish a differential pressure across SCSSV.
5. Wait an appropriate period of time and record surface pressure.
6. Surface pressure recorded in Step 5 confirms SCSSV holding integrity or the need to determine leakage rate addressed in Step 7.
7. Determine gas leakage rate using the following formula:

$$\text{Leakage rate (SCF/min)} = \frac{Cd^2h(p_2-p_1)}{T_{TEST}}$$

Where: C = 0.000363

d = Inside diameter of tubing in inches
h = Distance between valve and tree in feet p_1
= Initial pressure reading in psi p_2 = Final
pressure reading in psi T_{TEST} = Time lapsed
during test in minutes

Method B: PUMP THROUGH PLUGS

1. Record SITP.
2. Bleed surface pressure sufficiently to establish a pressure differential across pump-through plug or injection valve of approximately 20 percent of the SITP recorded in Step 1.
3. Wait an appropriate amount of time and record surface pressure.
4. Surface pressure recorded in Step 3 confirms pump-through or injection valve holding integrity, or the need to determine leakage rate addressed in Step 5.
5. Determine gas leakage with the following formula:

$$\text{Leakage rate (SCF/min)} = \frac{Cd^2h(p_2-p_1)}{T_{TEST}}$$

Where: $C = 0.000363$
d = Inside diameter of tubing in inches
h = Distance between valve and tree in feet p_1
= Initial pressure reading in psi p_2 = Final
pressure reading in psi T_{TEST} = Time lapsed
during test in minutes

NOTE:

For wells that contain no gas, determine leakage rate by capturing the leaking liquid in a measuring device.

APPENDIX 10

TESTING PROCEDURE FOR ESD AND FIRE LOOP SYSTEM

Testing Procedure for ESD System

1. Select well(s) or component(s) to be shut-in.
2. Bypass all SSVs and SCSSVs on wells not intended to be shut-in.
3. Bypass all component SSVs or pipeline SDVs not intended to be shut-in.
4. Activate ESD station
   A. Mechanical Control
      1. Move valve handle to the shutdown position (full open).
      2. Observe for free valve movement and unobstructed gas bleed. B. Electrical Control
      Push/trip electrical ESD control.
5. Verify that shut-in actuation of selected well(s) and component(s) has been achieved.
   A. Within 45 seconds for SSVs on well(s) and other selected surface components.
   B. Within 2 minutes thereafter for SCSSVs on selected well(s).
6. Return system to service.

Testing Procedure for Fire Loop System

Note: If possible, consideration shall be given to avoid total platform shut-in, as well as those wells which have a history of problems returning to flow after extended periods of being shut-in.

1. Select well(s) or component(s) to be shut-in.
2. Bypass all SSVs and SCSSVs on wells not intended to be shut-in.
3. Bypass all component SSVs or pipeline SDVs not intended to be shut-in.
4. Randomly select an area that is protected by the fire loop system.
   Direct the Operator to conduct an actuation test of the fire loop system in accordance with the Operator's test procedure.
5. Verify that shut-in actuation of selected well(s) and component(s) has been achieved.
   A. Within 45 seconds for SSVs on well(s) and other selected surface components.
   B. Within 2 minutes thereafter for SCSSVs on selected well(s).
6. Return system to service.

APPENDIX 14

TESTING PROCEDURE FOR FSL

1. Slowly close the valve on the media circulation pump discharge.

2. Watch a pressure drops with decrease inflow. The surge tank must be at significantly lower pump pressure than pump discharge pressure.

3. FSL should trip before the flow rate drops to 0 and before the discharge pressure drops below 50 percent of full discharge pressure.

APPENDIX 16

TESTING PROCEDURE FOR MOTOR STARTER INTERLOCK

1. Manually shut off motor starter to blower.

2. Verify interlock shuts down heater immediately.

3. Verify that PSL on blower trips after several seconds.

APPENDIX 17

TESTING PROCEDURE FOR FLAME ARRESTER

Visually inspect the flame arrester to verify that:

1. Flame arrester is clean and free of oil and paraffin residue.
2. Flame arrester is intact.

APPENDIX 19

TESTING PROCEDURE FOR WATER-FEEDING DEVICE

INSTALLED INTERNALLY

1. Adjust fuel gas controls so that the main burner of the steam generator shuts off. Assure continuous pilot light flame.

2. Shut off manual burner fuel valve.

3. Lower the water level of the vessel by opening the drain valve on the lowest portion of the steam generator and leaving it fully open.

4. Verify that the automatic water-feeding device initiates fill-up prior to exposing the fire tube.

5. Verify that the input rate exceeds the manual bleed rate by noting the rise in the water level.

6. Verify that the automatic water-feeding device ceases fill-up when the vessel is full.

INSTALLED EXTERNALLY

1. Adjust fuel gas controls so that the main burner of the steam generator shuts off. Assure continuous pilot light flame.

2. Shut off manual burner fuel valve.

3. Close isolating valves on float cage.

4. Drain cage to low level trip point.

5. Verify that the automatic water-feeding device initiates fill-up prior to exposing the fire tube.

6. Verify that the input rate exceeds the manual bleed rate by noting the rise in the water level.

7. Verify that the automatic water-feeding device ceases fill-up when the vessel is full.

APPENDIX 20

ELECTRICAL INSTALLATION REQUIREMENTS

DEFINITIONS:

High temperature device - Any device whose maximum operating temperature exceeds 726~ F.

Explosion-proof enclosure - An enclosure which is capable of withstanding an explosion of a gas or vapor within it and of preventing the ignition of an explosive gas or vapor which may surround it, and which operates at such an external temperature that a surrounding gas or vapor will not be ignited.

Hermetically sealed device - Any device which prevents a hazardous or corrosive gas from coming in physical contact with an arcing or high temperature component.

Non-incendive equipment - Electrical equipment which, in its normal operating condition, would not ignite a hazardous atmosphere in its most easily ignitable concentration.

General purpose equipment - Equipment which does not constitute a source of ignition (arcing, sparking, or high temperature devices) under normal operating conditions.

Area classification - See Appendix 21

Area classified as Division 1 - An area in which:

(1) Ignitable concentrations of flammable gases or vapors exist continuously, intermittently, or periodically under normal operating conditions;

(2) Ignitable concentrations of such gases or vapors may exist frequently because of repair or maintenance operations or because of leakage; or

(3) Breakdown or faulty operation of equipment or processes might release ignitable concentrations of flammable gases or vapors, and might also cause simultaneous failure of electrical equipment.

INSPECTION PROCEDURES:

1. Verify that all high temperature devices located in classified areas are installed in explosion proof enclosures.

2. Verify that hermetically sealed devices are not used in areas classified as Division 1.

3. Verify that non-incendive equipment is not used in areas classified as Division 1.

4. Verify that general purpose equipment is not used in areas classified as Division 1.

5. Verify that all electric generating stations are of the revolving field, brushless type.

6. Verify that all electric generating stations are powered by either natural gas or diesel fuel. Gasoline is not acceptable.

7. Verify that all electrical equipment is grounded in a positive manner.

8. Verify that all metal equipment (e.g., buildings, skids, and vessels) is grounded in a positive manner. Welding provides a positive ground while bolting does not.

9. Verify that each ground connector is either bare or if insulated is green or green with yellow stripe(s).

10. Verify that all lighting fixtures used in areas classified as Division 1 are explosion-proof.

11. Verify that all lighting fixtures are either protected or installed out of the way of moving objects.

12. Verify that all electric fire pumps have wiring systems which will withstand direct flame impingement for at least 30 minutes. The wiring system includes all feeder and control cables.

13. Verify that each cable support system is made of noncombustible material and provide rigid support of the electrical cable.

14. Verify that cables are individually secured and that cable trays have a rung spacing of not more than 12 inches.

15. Verify that all electrical installations appear to be free from worn insulation, missing parts, unprotected connections, corrosion, missing or worn seals,

APPENDIX 21

AREA CLASSIFICATION

PRODUCTION EQUIPMENT

Any area containing any of the following production equipment:

1. Flowing well
   A. Surface safety valve
   B. Sample valve, bleed valve, or similar device C.
   Wireline lubricator

2. Artificially lifted wells
   A. Beam pumping well
   B. Electric submersible pumping well
   C. Hydraulic subsurface pumping well
   D. Gas lift well

3. Injection wells
   A. Flammable gas or liquid
   B. Nonflammable gas or liquid

4. Multi-well installations

5. Oil and gas processing and storage equipment A.
   Flammable liquid storage tank
   B. Combustible liquid storage tank
   C. Hydrocarbon pressure vessel
   D. Header or manifold
   E. Fired equipment
   F. Vents
   G. Relief valve
   H. Launcher or receiver
   I. Ball or pig launcher or receiver J.
   TFL tool launcher or receiver
   K. Dehydrator, stabilizer, and hydrocarbon recovery unit

6. ACT unit

7. Flammable gas-blanketed and produced water-handling equipment

8. Gas compressor or pump handling volatile, flammable fluids

9. Hydrocarbon-fueled prime movers

10. Instruments
    A. Not operated by flammable gas
    B. Operated by flammable gas

11. Sumps

12. Drains

13. Valves and Valve Operators
    A. Block valves and check valves
    B. Process control valves
    C. Valve operators

    D. Sample, bleed and drain valves, and similar devices.

DRILLING EQUIPMENT

Any area containing any of the following drilling equipment:

1. Rig floor and substructure areas

2. Mud tank

3. Mud pump

4. Shale shaker

5. Desander or desilter

6. Degreaser

7. Diverter line vent

8. BOP

APPENDIX 22

WELL-CONTROL DRILL REQUIREMENTS

ON-BOTTOM DRILLING

A drill conducted while on bottom shall include the following as practicable:

1. Detect kick and sound alarm.

2. Position kelly and tool joints so connections are accessible from floor, but tool joints are clear of sealing elements in BOP systems, stop pumps, check for flow, close in the well.

3. Record time.

4. Record drill-pipe pressure and casing pressure.

5. Measure pit gain and mark new level.

6. Estimate volume of additional mud in pits.

7. Weight sample of mud from suction pit.

8. Check all valves on choke manifold and BOP system for correct position (open or closed).

9. Check BOP system components and choke manifold for leaks.

10. Check flow line and choke exhaust lines for flow.

11. Check accumulator pressure.

12. Prepare to extinguish sources of ignition.

13. Alert standby boat or prepare safety capsule for launching.

14. Place crane operator on duty for possible personnel evacuation.

15. Prepare to lower escape ladders and prepare other abandonment devices for possible use.

16. Determine materials needed to circulate out kick.

17. Time drill and enter drill report on driller's report.

TRIPPING PIPE

A drill conducted during a trip shall include the following as practicable:

1. Detect kick and sound alarm.

2. Install safety valve, close safety valve.

3. Position pipe, prepare to close annular preventer.

4. Install inside preventer, open safety valve.

5. Record time.

6. Record casing pressure.

7. Check all valves on choke manifold and BOP system for correct position (open or closed).

8. Check for leaks on BOP system component and choke manifold.

9. Check flow line and choke exhaust lines for flow.

10. Check accumulator pressure.

11. Prepare to extinguish sources of ignition.

12. Alert standby boat or prepare safety capsule for launching.

13. Place crane operator on duty for possible personnel evacuation.

14. Prepare to lower escape ladders and prepare other abandonment devices for possible use.

15. Prepare to strip back to bottom.

16. Time drill and enter drill report on driller's report.

APPENDIX 23
BOP SYSTEM AND AUXILIARY EQUIPMENT

BOP systems and auxiliary equipment may include but not limited to:

1. Annular and ram-type preventers.
2. Choke and kill lines with various valve assemblies.
3. Remote control stations.
4. Diverter lines.
5. Choke manifolds and valve assemblies.
6. Upper and lower kelly cocks, inside BOP valves, and drill string safety valves.

Note: All test pressures and test schedules may be altered by approval of District Manager.

Sample Calculation of the Maximum Pressure to Protect the Formation at the Casing Shoe:

$$MP = (Emw - Pmw) \times 0.052 \times D$$

Where: MP = Maximum pressure to be contained under the BOP in psi. Emw = Equivalent mud weight from formation pressure integrity test (PIT) at the shoe of the last casing string in lbs/gal. Pmw = Present mud weight in use in lbs/gal. 0.052 = Conversion factor (weight to pressure) D = Present drilling depth in feet.

REMOTE BOP CONTROL STATION

Unit must have capability of functioning all components of the stack and diverter system.

ACCUMULATOR SYSTEM

1. Identify the primary and secondary independent power sources.
2. Each component must have an individual control valve.
3. Unit must be properly sized and pressurized.
4. Air regulators must have overrides or secondary air source.
5. Blind/blind shear ram control valves may be caged but never locked in neutral position.

Test Procedure:

1. Identify and turn off the primary power source.
2. Open the manifold bleed valve to the accumulator fluid reservoir.
3. Allow the pressure to drop enough for the secondary power source to begin building pressure automatically (no more than 1/3 of the initial pressure).

4. Turn on the primary power source to observe both systems building pressure and turn off automatically.

Surface Stack Accumulator Size Calculations:

BOP Equipment	Gallons to Close
Typical Annular BOP (13 5/8 inches, 5k) 23.6 Three Typical Ram BOP's (13 5/8 inches, 10k) [11.6 gal. x 3] 34.8 Two Typical Hydraulic Valves (4 inches HCR, 5k) [0.52 gal x 2]	1.1
Total Gallons for Closure [round to 60]	59.5
BOEMRE Regulations [Total Gallons x 1.5]	90
Manufacturer Recommendation [Total Gallons + 50% SF x 2]	180

Typical 3000 psi System
1. Precharge Condition - 1000 psig
1. Full Charge Condition - 3000 psig
2. Discharged or Used Condition - 1200 psig*
(* BOEMRE Requirement - 200 psi above precharge)

Usable fluid in 11 gallon cylinder type	5
Usable fluid in 80 gallon spherical type	54

Typical 3000 psi System (as noted above):
1. BOEMRE - 18 cylinder or 2 spherical
2. Manufacturer - 36 cylinder or 4 spherical

DIVERT

ER SYSTEM

1. Check for sizing, installation, and remote capability.
2. Drive Pipe - Actuated and flow tested.
3. Conductor - 200 psi minimum test and flow tested.
4. Actuated every 24 hours.
5. Retest every 7 days if used for that length of time.
6. No manual or butterfly valves allowed.
7. Diverter lines > 8 ft. in length from the outlet valve flange will require support.
(Memo 8-28-98)

BOP STACK

Check for:

1. Installation with proper number of ram-type and annular preventers, choke and kill lines, valves, control lines, and remote operation capability. Only the kill line can be installed below the ram type preventers.
2. Properly sized inside BOP and drill string safety valves in open position on rig floor.
3. Upper and lower kelly cocks with wrenches or top drive valves when applicable.
4. Dual pod system on subsea installations.

TESTING

1. Surface BOP, subsea BOP stump test, and auxiliary equipment must be tested with water. (Completion stacks may be tested with filtered completion fluid if approved.)
2. All BOP tests must have an associated test chart and a reference document if necessary.
3. All tests must be properly recorded.
4. Low Pressure Test - (Conducted prior to the high test) Between 200 and 300 psi.
   Initial pressure above 300 psi but less than 500 psi may be bled back to the required pressure.
   Initial pressure above 500 psi must be bled to zero and re-pressured.
5. High Pressure Test - Test pressure for the high pressure test must not exceed the working pressure of the BOP or the wellhead assembly rating, whichever is lesser, by more than 10% during initial build up.

APPENDIX 24

CRANE USE CATEGORIES AND INSPECTIONS

Infrequent Usage

Used 10 hours or less per month, based on the average use over a quarter. These cranes will be subject to a pre-use and an annual inspection.

Moderate Usage

Used more than 10 hours but less than 50 hours per month, based on quarter average. These cranes will be subject to a pre-use, quarterly, and an annual inspection.

Heavy Usage

Used 50 or more hours per month. These cranes will be subject to a pre-use, monthly, quarterly, and an annual inspection.

INSPECTIONS

Monthly - Anytime during the calendar month.
Quarterly - Every three months (January, February, & March = 1st quarter; April, May, & June = 2nd quarter, etc.)
Annual - Every 12 months

FREQUENTLY ASKED QUESTIONS

Q: Crane was inspected for monthly on 3/5/2000, when is my next monthly due?
A: No later than 4/30/2000, O.K. to the last day of the month.

Q: Crane was inspected for quarterly on 1/20/2000, when is my next quarterly due?
A: No later than 4/30/2000, O.K. to the last day of the month.

Q: Crane was inspected for annual on 4/1/1999, when is my next annual due?
A: No later than 4/30/2000, O.K. to the last day of the month.

Q: When a crane shifts from moderate to heavy use, when is the monthly due?

Q: When a crane shifts from infrequent to moderate use, when is the quarterly due?
A: By the end of the first month of the quarter following the shift.

A: By the end of the month following the shift, followed by a monthly or quarterly, as needed to set up the required inspection schedule.

APPENDIX 25

PIT VOLUME TOTALIZER TEST

PROCEDURE **<u>Recommended procedure for Alarm Setting:</u>**

To determine loss/gain setting and calibration of the recorder, lift and lower the indicator float in the mud pit to activate the alarm and verify the calibration of the recorder. The recommended maximum and minimum tolerance for the mud volume measuring device is ± 10 bbls.