Cementing Shallow Water Flow Zones in Deepwater Wells

API RECOMMENDED PRACTICE 65
FIRST EDITION, SEPTEMBER 2002
ERRATA, AUGUST 2003

American
Petroleum
Institute

**Helping You
Get The Job
Done Right.**SM

Cementing Shallow Water Flow Zones in Deepwater Wells

Upstream Segment

API RECOMMENDED PRACTICE 65
FIRST EDITION, SEPTEMBER 2002

American
Petroleum
Institute

Helping You Get The Job Done Right.SM

SPECIAL NOTES

API publications necessarily address problems of a general nature. With respect to particular circumstances, local, state, and federal laws and regulations should be reviewed.

API is not undertaking to meet the duties of employers, manufacturers, or suppliers to warn and properly train and equip their employees, and others exposed, concerning health and safety risks and precautions, nor undertaking their obligations under local, state, or federal laws.

Information concerning safety and health risks and proper precautions with respect to particular materials and conditions should be obtained from the employer, the manufacturer or supplier of that material, or the material safety data sheet.

Nothing contained in any API publication is to be construed as granting any right, by implication or otherwise, for the manufacture, sale, or use of any method, apparatus, or product covered by letters patent. Neither should anything contained in the publication be construed as insuring anyone against liability for infringement of letters patent.

Generally, API standards are reviewed and revised, reaffirmed, or withdrawn at least every five years. Sometimes a one-time extension of up to two years will be added to this review cycle. This publication will no longer be in effect five years after its publication date as an operative API standard or, where an extension has been granted, upon republication. Status of the publication can be ascertained from the API Upstream Segment [telephone (202) 682-8000]. A catalog of API publications and materials is published annually and updated quarterly by API, 1220 L Street, N.W., Washington, D.C. 20005.

This document was produced under API standardization procedures that ensure appropriate notification and participation in the developmental process and is designated as an API standard. Questions concerning the interpretation of the content of this standard or comments and questions concerning the procedures under which this standard was developed should be directed in writing to the standardization manager, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005. Requests for permission to reproduce or translate all or any part of the material published herein should also be addressed to the general manager.

API standards are published to facilitate the broad availability of proven, sound engineering and operating practices. These standards are not intended to obviate the need for applying sound engineering judgment regarding when and where these standards should be utilized. The formulation and publication of API standards is not intended in any way to inhibit anyone from using any other practices.

Any manufacturer marking equipment or materials in conformance with the marking requirements of an API standard is solely responsible for complying with all the applicable requirements of that standard. API does not represent, warrant, or guarantee that such products do in fact conform to the applicable API standard.

FOREWORD

Unless indicated otherwise, laboratory procedures referenced in this document are performed according to API recommended practices on equipment that has been calibrated according to guidelines in the appropriate API recommended practice.

This document has been prepared with input from operators, drilling contractors, service companies, consultants and regulators. It is based on experiences in the U.S. Gulf of Mexico. Users in other deepwater basins may use the document with appropriate modifications to meet their conditions. The document focus is on the drilling and cementing of casings in the shallow sediments of deepwater wells in which highly permeable and over-pressured sands are found. These over-pressured sands frequently lead to flows of water during drilling and casing operations and after cementing. Such flows can have very costly and catastrophic results if not controlled. The body of the document discusses pertinent points relating to site selection, drilling and cementing the large diameter casing strings placed in this environment. A number of "best practices" have been developed by those involved in constructing wells in deep water and are discussed throughout the text. In addition, appendices deal with some specific aspects of the process, including drilling practices, cementing process and interpretation of the shallow flow risk.

As this document has been a team effort, so must the drilling and casing of the shallow sediments where there is risk of shallow water flows (SWF). All parties involved must be working and communicating together to ensure the successful construction of the conductor and surface casings through the shallow hazards.

API publications may be used by anyone desiring to do so. Every effort has been made by the Institute to assure the accuracy and reliability of the data contained in them; however, the Institute makes no representation, warranty, or guarantee in connection with this publication and hereby expressly disclaims any liability or responsibility for loss or damage resulting from its use or for the violation of any federal, state, or municipal regulation with which this publication may conflict.

Suggested revisions are invited and should be submitted to the standardization manager, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005.

CONTENTS

Cementing Shallow Water Flow Zones in Deepwater Wells

1 Scope

1.1 FLOWS

This document is the compilation of technology and practices used by many operators drilling wells in deep water. In a number of cases, there is not a single way of performing a specific operation. In some cases, several options may be listed, but in others there may be practices which are successful, but which are not listed in this document. This document is not meant to limit innovation.

In wells drilled in deep ocean waters, water flows from shallow formations can compromise the hydraulic integrity of the tophole section. Modes of failure include: (1) poor isolation by cement resulting in casing buckling/shear; (2) pressure communication to other shallow formations causing them to be overpressured; and (3) disturbance of the seafloor due to breakthrough of the shallow flow to the mudline. Such damage can and has resulted in the complete loss of drilling templates containing previously cased wells. Additionally, such shallow flow can result in changes in the state of stress in the tophole section, possibly resulting to damage to existing casings in the present or adjacent wells later in the life of the well.

Flows from these shallow formations are frequently a result of abnormally high pore pressure resulting from undercompacted and over-pressured sands caused by rapid deposition. Not all flows are the result of these naturally developed formation geo-pressures. Hydraulic communication with deeper, higher pressure formations is another cause for abnormal shallow pressures. Some of the observed shallow flow problems have been due to destabilization of gas hydrates or induced storage during drilling and casing and cementing operations. Although minor compared to geo-pressured sands, flows due to induced storage may still cause damage from sediment erosion or mining, breakthrough to adjacent wells and damage to the cement before it sets. These problems can worsen with each additional well when batch setting shallow casings. Although most of the discussion in this text is focused on shallow water flow (SWF), shallow flows can be mixtures of water, gas and formation fines. In most cases the concepts are similar and can be employed with minor modifications, depending on the type of flow.

Flows allow production of sand and sediments resulting in hole enlargement which can increase the flow potential and make it more difficult to control. The enlargement may also cause caving of formations above the flow interval. The flow of water and formation material from these zones can result in damage to the wells including foundation failure, formation compaction, damaged casing (wear and buckling), reentry and control problems and sea floor craters, mounds and crevasses (OTC 11972, IADC/SPE 52780).

1.2 HAZARDS

The Gulf of Mexico has been divided into areas by the severity of the hazard based on data from geotechnical wells (SPE/IADC 67772). The Minerals Management Service (MMS) also maintains a map showing the location of flow incidents on a web site at http://www.gomr.mms.gov/homepg/offshore/safety/wtrflow.html.

The following factors make drilling in deep water with SWF potential unique:

a. Temperatures at the mud line and through the shallow sediments are quite low and may approach 40°F.
b. Pore and fracturing pressures are very close, making the drilling window very narrow.
c. The hole is drilled riserless, with returns taken to the sea floor.
d. Seawater is used for drilling.
e. There is no means to control flow at the wellhead.
f. Returns and flows are observed only remotely through video from a remotely operated vehicle (ROV).
g. In development projects, conductor and surface casing are batch set.

The shallow water flow conditions described in this document exist in wells drilled in water depths greater than about 500 ft and more commonly at water depths greater than 1000 ft. These wells are commonly drilled from floating drilling rigs such as drill ships, semi-submersibles, spars and tension leg platforms.

Shallow water flow sands are typically encountered at depths of 600 ft – 2500 ft below mud line (BML). The conditions favoring the formation of shallow water flow sands include:

a. High rate of deposition (> 1500 ft/million years) sedimentary basins of current or ancestral river complexes, such as the Mississippi River depocenter.
b. Areas with substantial regional uplift, in which once deeply buried sediments are encountered at shallow depths—North Sea, Norwegian Sea.
c. Continental slope regions subject to large scale subsea slides—Storegga Slide area, Norwegian North Sea.

Abnormal pressures may be present in the top hole section of a deepwater well. Abnormal pressure can be trapped below the impermeable layers found above the SWF sands, or may begin at or near the mud line and increase more-or-less linearly with depth. In general, the degree of over-pressurization is consistent with the rate of deposition. Pore pressures equating to 8.6 lbm/gal to 9.5 lbm/gal equivalent mud weight (EMW) may be encountered in the SWF zones. When abnormal pressures are trapped below impermeable barriers, the pore pressure can be very close to the fracture gradient of the sediment. This results in a very narrow pressure margin within which drilling operations must be conducted to maintain well control and prevent induced fracturing of formations. (See SPE/IADC 67772.) The margin between pore pressure and fracture gradient becomes more narrow as water depth increases.

Temperatures at the mud line of a deepwater wellbore are quite low, in the range of 35°F – 55°F depending on water depth, latitude, and presence of warm/cold ocean currents. The low temperatures result in slow hydration of the cement making special slurries and/or additives necessary. The geothermal gradients found in deepwater areas may be sequestered as a result of the water depth effect and may suppress wellbore temperatures throughout the entire stratigraphic column. In other areas the geothermal gradient may rise quickly to normal values as depth increases.

1.3 BEST PRACTICES

Because of such problems and to form an effective seal while preventing flow, careful attention must be paid to the cementation of wells having the potential for shallow flow. This document addresses the drilling and cementing process and makes recommendations for such wells. Appendix F gives a matrix for this process with values for each step. The resultant score provides the user with a factor of the relative chance of success of the cementation process. This process and matrix are based on known industry practices and are meant to be used to apply the process within the constraints of the well conditions with the greatest degree of risk minimization.

The process includes:

a. Site selection.
b. Drilling.
c. Fluid properties.
d. Wellbore preparation and conditioning.
e. Operational procedures and good cementing practices.
f. Mud removal and placement technique.
g. Cement slurry design.
h. Pre-job preparation.
i. Cement job execution.
j. Additional considerations.
k. Post cementing operations.
l. Remediation of flows.

A number of "best practices" have been developed for drilling and cementing in the deepwater, shallow water flow environment. Generally, these have been developed from lessons learned while drilling deepwater wells. These practices are applied to minimize the risk of shallow water flow and to aid in successfully drilling and cementing the casing through the SWF zones. These practices include the following, which are discussed in more detail throughout the document.

a. *Site selection to minimize the risk for and severity of shallow water flow.*
b. *Use of pressure while drilling and resistivity tools to identify permeable sands and flow events.*
c. *Use of ROV to check for flow with each connection.*
d. *Rapid action to contain flows.*
e. *Switching to mud to control flow as soon as it is encountered.*
f. *Selection of casing seats/casing program to facilitate control and to reach the well objectives.*
g. *Low fluid loss and gel strengths of pad mud spotted in the hole just prior to running casing.*
h. *Use of foamed cement and/or special slurries to maintain control across the SWF zones.*
i. *Batch setting conductor and surface casings.*

A list of "lessons learned" in successfully isolating the top hole section in the presence of SWF include the following:

a. The pore pressure of SWF sand(s) must be hydrostatically contained at the first indication of flow.
b. SWF zones that are drilled underbalanced while flowing will not likely be isolated with cement.
c. Flows that are not contained soon after beginning can jeopardize the success of the project.
d. Wells in which the SWF sands have been hydrostatically controlled must still be cemented with flow mitigating cement systems.
e. Mechanical isolation devices, when used without flow mitigating cement systems, may not provide zonal isolation over the life of the well.

Note that this document is not meant to be a training manual. Although fairly comprehensive, there are still many details which are not discussed and which must be addressed when drilling and cementing wells in deep water. It is meant to highlight key parameters for increasing the chance of successfully drilling and cementing casings where there is a risk of shallow water flow and to discuss options that are available. Many more details can be gleaned from the references listed in the Bibliography. Most of the information in this document is from U.S. Gulf of Mexico experience. The concepts can be applied in other deep water environments with appropriate modifications. The user should consult experts within the industry for specific details of the cementing process relating to the technology being employed by a specific company for a specific scenario. The construction of the casings through the SWF zones must be a team effort to be successful. All parties involved must participate in the planning and execution of all phases of the process to ensure successful construction of the conductor and surface casings.

2 References

API

RP 10B	*Recommended Practice for Testing Well Cements,* 22nd Edition, December 1997
RP 75	*Recommended Practice for Development of a Safety and Environmental Management Program for Outer Continental Shelf (OCS) Operations and Facilities*

ISO

10426-2	*Petroleum and natural gas industries—Cements and materials for well cementing—Part 2: Recommended practice for testing of well cements*
10426-3	*Petroleum and natural gas industries—Cements and materials for well cementing—Part 3: Recommended practice for testing of deep water well cements*. Working Draft

3 Terms and Definitions

3.1 BHA: Bottom hole assembly

3.2 BML: Below mud line

3.3 critical gel strength period: Time required for the cement to progress from Critical Static Gel Strength to a static gel strength of 500 lb/100 ft^2.

3.4 critical static gel strength: Gel strength of the cement that results in hydrostatic decay producing an exactly balanced condition in the well.

3.5 flow checks: An observation, usually by ROV when riserless, of the condition of the well during a non-circulating period to determine if flow is occurring.

3.6 ROP: Rate of penetration.

3.7 ROV: Remotely operated vehicle.

3.8 SWF: Shallow water flow.

3.9 WOB: Weight on bit.

3.10 WOC: Wait on cement.

4 Site Selection

Well location can affect the risk and severity of shallow water flow (IADC/SPE 52780). Use best available data, including shallow seismic and data from offset exploratory, appraisal and geotechnical wells, to select a site which can reach the well target(s) with the least risk. Where "in-house" expertise is not available, commercial services can be used to assist in shallow hazard identification and analysis.

Flow risks can be characterized as negligible, low, moderate or high. Keep in mind that it is difficult to judge the severity of a SWF. The following is a description of each, based on one set of evaluation criteria. The evaluation criteria are listed in Appendix A. The potential well location can be evaluated to determine the potential for flow using this "interpretation guide." If the risk is not acceptable, alternative locations can be evaluated to find the one with the least risk of flow.

High—An interval possessing all of the characteristics of a shallow water flow interval, or that ties directly to a shallow flow in an offset well, or is located at a known regional, shallow flow horizon.

Moderate—An interval meeting the criteria listed above for "High" risk, but which could be breached, or otherwise shows evidence that provides reasonable doubt for the presence of shallow flow conditions.

Low—An interval generally lacking the characteristics of a shallow water flow interval, although some interpretive doubt exists.

Negligible—An interval where data clearly indicate there is no risk of either sand or adequate seal, or where offset drilling has proven the absence of flow risk.

Any one indication can be spurious. Shallow water flow interpretation on seismic data involves accumulation of evidence. The more points that can be answered by a "yes", the greater the risk that shallow flow conditions are present.

Several references address assessment of SWF risk. They can be read to assist in determining SWF risk. See Trauggott and Heppard, "Pressure Prediction for Shallow Water Flow Evaluation"; Huffman and Castagna, "Rock Physics and Mechanics Considerations for Shallow Water Flow Characterization"; and SPE/IADC 67772, "Trends in Shallow Sediment Pore Pressures—Deepwater Gulf of Mexico."

5 Drilling

Individual well spacing and drilling order should minimize the impact on adjacent wells. Well arrangement with the greatest distance between adjacent wells can reduce the risk of damage to a well from an adjacent well that is experiencing flow. Flow can cause changes in the mechanical stresses affecting both the well experiencing the flow and adjacent wells.

The condition of the hole will have a major bearing on the quality of the cementation. Thus, the hole should be drilled in such a manner to produce a condition that allows the best cementation to be achieved. Critical elements of the hole condition include the diameter and shape of the borehole. Large washouts make it difficult to successfully install and cement a casing string, which can lead to later problems like load shedding, casing buckling and wear. Casing buckling in the washed-out sands may prevent physical reentry into the well. Uncontrolled flows can also lead to compaction and subsidence of the flow zones, impacting the integrity of nearby wells or structures.

If the borehole is washed out or enlarged, effective fluid displacement regimes are more difficult to accomplish. Additionally, washouts make centralization (an important element of effective mud removal) more difficult. Doglegs make centralization more difficult to achieve as well. Care should be taken to minimize doglegs and washouts.

Washout or hole enlargement is controlled in a variety of ways, depending on the enlargement mechanism.

Most important is to prevent wellbore enlargement due to the mining of sand by preventing or minimizing shallow water flows. Wellbore enlargement in sand formations can also be caused by hydraulic erosion. Hydraulic erosion is caused by excessive bit nozzle velocity and turbulence at the bit. Secondary erosional effects can be limited by controlling the annular velocity to avoid turbulence across the bottom hole assembly (BHA).

These effects may be managed by controlling drilling mud properties, nozzle velocity and annular velocity to minimize turbulence. Additionally, when circulating sweeps, do not leave the bit across sands.

Another factor affecting hole enlargement is the fluid loss characteristics of the drilling fluid. High fluid loss leads to high near-wellbore pore-pressures (no distinct pressure gradient across a sealing filter cake). This means that near-wellbore pore pressure is equal to mud pressure and near-wellbore radial effective stress is zero such that there is no effective overbalance acting to support the formation. This in turn can aggravate hole washout and promote tophole collapse.

Lost circulation should be prevented as well. Losses are due to pressures in the wellbore exceeding the breakdown pressures of weak, poorly consolidated formations. These pressures may be due to high fluid weight, excessive cuttings loading or high frictional pressure. The mud weight is maintained between the minimum necessary to control shallow water flows and the maximum at which weak formations are broken down, preferably, close to the minimum. The difference between this minimum and maximum can be very small. The frictional pressure, combined with the hydrostatic pressure of the fluid should be kept below the pressure at which the formations are broken down. A contributing factor to the combined pressure is the cuttings which are carried out of the well by the drilling fluid. The amount of cuttings in the fluid can be controlled to avoid exceeding the fracture gradient. In order to do this, the flow rate should be balanced against controlling the rate of penetration (ROP) (to reduce production of cuttings) and weight on bit (WOB)/RPM (to reduce the size of the cuttings, making them more easily removed from the well.) Additionally, circulating bottoms up on each stand and using viscous or weighted sweeps may aid in keeping the hole clean, depending on well bore conditions, flowrates, and type of drilling fluid.

Pressure while drilling measurements can aid in borehole pressure management. When pressure increases are noted, remedial action can be taken to avoid breaking down weak formations. Additionally, pressure while drilling measurements can be used to recognize flows and begin to take appropriate action to mitigate them (SPE/IADC 52781, SPE 62957, OTC 11972). Resistivity at the bit can also be used to indicate when potential overpressured sands have been penetrated (SPE/IADC 52781).

ROP should be controlled as indicated by pressure while drilling readings or hydraulic modeling and pressure management. ROP is also a concern due to its impact on time drilling opposite sensitive shales, as well as the time these shales are exposed to well fluids and pressures. ROP criteria can be established to balance the requirement to minimize cuttings loading and the exposure of sensitive shales.

To detect flows as early as possible, constantly monitor returns by video on board the ROV. Additionally, flow checks should be made after each connection and after sweeps to determine if shallow flow is occurring. Monitoring for as long as one hour may be required when weighted mud is in the hole. If SWF is encountered, the flow should be killed as quickly as possible. The rate of shallow water flows is difficult if not impossible to judge based on visual ROV observations. With this in mind, allowing a seemingly "smaller" flow for even short periods of time may later result in an unacceptable wellbore for cementing and subsequently isolating the flow.

The well should be static when attempting to cement casing across formations capable of flowing. For best results, there should be no flow and minimal mud losses, either due to lost circulation or to fluid loss. Appropriate lost circulation material (LCM) and bridging agents should be used to minimize mud losses during static periods immediately prior to cementing. In addition, whenever kill or pad mud is used, it should be formulated to have fluid loss control. High fluid loss can result in thick filter cake, which in turn can make removal and subsequent zonal isolation by the cement difficult.

Prevention of SWF ensures the highest probability of successfully attaining the objective of setting casing with a competent cement sheath. Close attention should be paid to the details of job planning and execution to avoid flows which require remediation. If flows occur, *minimize the flowing time* to avoid washout of the hole.

Drilling on a single trip with a full diameter bit minimizes the time the hole is open, reduces the number of trips and is suited to locations where the conditions and severity of SWF are known.

For locations with a high SWF potential and conditions are not known, either drilling a smaller diameter pilot hole to determine formation properties and the presence and severity of SWF zones (SPE 52781) or having a weighted sacrificial mud available is recommended. If SWF zones are encountered, a smaller diameter pilot hole makes dynamic kills easier to achieve, while a large volume of weighted sacrificial mud would allow SWF control in any sized hole. The risk of a SWF should be evaluated against the need for sacrificial mud and any constraints imposed by its use in opening the smaller diameter hole to run casing. These factors plus the rig's sacrificial mud storage capacity, drill pipe size, and mud pump capacity should be used to choose the most appropriate approach for these areas.

6 Flow Control and Severity

6.1 FLOW CONTROL

Attempts to kill the flow soon after it starts or just after the flow zone has been drilled increase the probability of killing/shutting off the flow (SPE 62957, SPE/IADC 52781). After extensive flow has occurred or after cementing, successful control of flows can be difficult to achieve. Reasons for immediate attempts to control the flow are:

a. Minimizing flow time reduces wellbore washout, instability and possible damage to nearby wells.

b. Location of the flow zone is at an optimal place in the wellbore (on bottom) for spotting and treating to shut off flow.

c. If flow can not be controlled, immediate abandonment can reduce further expenditure and reduce formation disturbance effects on adjacent wells.

Flows should be killed as soon as possible using kill weight mud. This implies the need to maintain sufficient mud on location to be able to kill and control the flow. Most of the time, large volumes of kill weight fluid are maintained on the rig or in stand-by support vessels. Frequently this fluid is in the form of a high density, concentrated mud which is diluted to the required density as it is being used (IADC/SPE 59172, SPE/IADC 52781).

If flow occurs outside the previous casing or if the sands are continuous and well connected with a charging aquifer, the probability of successfully isolating the sand with casing and a good integrity cement job can be low. The probability of success may be better if the flow is drilling induced and sands are not highly charged or well connected. Flow outside the casing can be observed by ROV. The site should be evaluated and strong consideration given to site abandonment and relocation if the flow cannot be controlled.

6.2 FLOW SEVERITY

The severity of geopressure flows and their potential impact on cementing operations can be characterized as follows:

a. Flows that can be controlled without lost circulation or the lost circulation is cured.

1. High probability of success.
2. High performance, non-foamed cement slurries extended with glass beads/pozzolan microspheres may be used.
3. Foamed cements are recommended.

b. Flows that cannot be controlled without complete lost circulation.

1. Probability for successful cementing operations is extremely low.
2. Foamed cements are recommended.
3. Large cement volumes are recommended to kill flow for well abandonment.

Operators should consider developing independent criteria for determining flow severity. Such methods could include measurement of pressures while drilling. If the severity is not known, prudence dictates that flows should be assumed to be severe and operations conducted accordingly.

7 Fluid Properties

7.1 GENERAL

Consideration should be given to the nature and method of use of fluids when selected for wells drilled in deep water. Typical fluids are used for drilling, killing the well and to protect the rat-hole during cementing. Each of these will have different properties. When used in the well with returns taken to the seabed, the fluids must be formulated to satisfy the prevailing regulatory environmental discharge regulations. When encountering a flow and mudding up, the density of the fluid, whether for drilling or for killing the flow, should be adequate to kill the well and maintain it in a static condition and without losses while the well is being prepared for and during the cementing process. The density should be in the low end of the range between the pore pressure equivalent and the fracturing pressure equivalent. This allows a greater differential between cementing fluids and the wellbore fluid, which will aid in mud displacement.

7.2 SACRIFICIAL OR CUT MUD

Although seawater is commonly used and is quite effective above the SWF interval, the fluid used to drill the interval with high potential for flow should be selected based on the considerations mentioned under "Drilling" above. Frequently, mud is made in batches and stored in a concentrated form (higher density) to conserve storage space. When needed, this mud is then diluted to the desired density for well control and to finish drilling the potentially flowing interval.

When drilling with seawater or after the hole is drilled with mud, sweeps should be used to clean the hole prior to placement of kill or pad mud. The use of high viscosity, weighted or foamed sweeps will enhance hole cleaning. To be effective, sweeps must have significantly different properties (higher viscosity and/or density) than the existing mud and must be of sufficient volume to cover 100 linear ft to 250 linear ft of annulus. Due to their unique rheological properties, foamed sweeps are very effective (OTC 8304). Such a sweep uses a weighted fluid foamed to the desired weight. As a minimum, a sweep should be used to remove cuttings upon reaching TD.

7.3 PAD MUD (FLUID LEFT IN HOLE PRIOR TO CEMENTING)

Consideration should be given to the fact that the kill fluid will remain in the hole until it is circulated out during the cementation. Thus, the kill fluid properties should be conducive to removal by the fluids and flow regimes used in the cementing process. Additionally, the fluid properties should be selected with the idea of controlling hole washout or sloughing/caving—this is typically done by controlling fluid loss.

The kill or pad mud should have proper fluid loss control to prevent uncontrolled filter cake development. A mud with low fluid loss and a thin, tough, filter cake is recommended. For ultra-high permeability, shallow sands with high SWF potential, bridging agents (medium-to-coarse granular lost circulation materials) may be required to prevent whole mud leak-off which could result in a loss of hydrostatic and a subsequent flow. The rheology of the kill or pad mud should be controlled so the fluid can be adequately displaced during the cementing process. Generally, the gel strengths should be low and “flat” such that they are not progressive or increasing with time as the fluid remains static.

7.4 SETTABLE FLUIDS

In some cases, hole conditions (such as washouts and lost circulation) may not allow effective displacement of all the drilling/kill fluid by the cementing fluids. In this case, methods to convert the undisplaced drilling/kill fluids into a cementitious material can be employed. (See subsequent discussions about mud removal). These technologies can be provided by the drilling fluids provider.

7.5 RAT HOLE FLUID

If casing is not to be run to bottom, the “rat hole” should be filled with a higher weight mud. This is to prevent cement from falling into the rat hole and displacing rat hole fluid into the cement column, compromising the cement’s properties. The fluid should be of adequate density and properties that there will not be a tendency for the fluid to swap with the cement as it is being placed. The fluid spotted in the rat hole should be treated, in much the same way as the other kill or pad muds, to minimize washout and wellbore instability.

8 Wellbore Preparation And Conditioning

8.1 GENERAL

Every effort should be made to minimize the time between completion of the hole interval and cementing when shallow water flow hazards exist. With the cementing process in mind, the fluids used to drill and kill the well must be designed for ease of removal. If it is prudent after the well has been killed, consideration should be given to replacing the kill fluid with fluids more readily removed during the cementing process. Conditions should be maintained to minimize changes in hole conditions which would lead to difficulty achieving a seal during the cementing operation.

8.2 WELL PREPARATION

Well preparation, particularly circulating and conditioning fluids in the wellbore, is essential for successful cementing. Many poor primary cementing results are the result of difficult to displace fluids and/or inadequate wellbore conditioning. Particular attention should be placed on low fluid loss (thin, tough filter cake) and rheological properties that provide low, flat gel strengths.

Even when good well preparation is planned, contingencies in the cementing operation should be provided in case well conditions prevent the planned well conditioning program from being performed.

Well preparation includes:

a. Proper placement of kill/pad mud in the well. Such fluid should include design of rheological properties to aid in its removal by the cementing fluids.

b. Ensuring the well is dead and there are no losses.

c. Conditioning of fluids prior to cementing to ensure that gel strength is broken, and that cuttings and gas are removed.

8.3 LOST CIRCULATION

Lost circulation should be avoided whenever possible. The pressure in the wellbore should be kept below the fracture pressure by controlling the mud weight, and managing annular friction pressure losses and cuttings loading. The methods of doing this have been discussed previously in the section on drilling.

Lost circulation poses a serious risk to successful cementing operations. Lost circulation should be cured prior to the start of the cementing operation. Failure to do so substantially increases the risk of failure to achieve zonal isolation or structural failure of the well. This is particularly true for multi-well templates.

9 Operational Procedures and Good Cementing Practices

9.1 GENERAL

After the interval has been drilled, avoid undue delays in preparing for and cementing. Casing with appropriate hardware should be made up and run as quickly as prudently possible. That being said, care must be taken when running casing to ensure that surge pressures are not so great as to break down the poorly consolidated formations. Computer simulators can be used to model the surge pressures to determine an appropriate rate for running casing. Drillers should be instructed in the proper running speed. If a casing wiper plug is used, a float shoe or guide shoe and float collar should be run to provide a volume of cement to avoid over-displacement of the primary sealing cement. The volume of the shoe joint(s) should be adequate to allow for any contamination of the cement by displacement fluid while placing the cement.

Casing should be filled with water or, in the case of potential shallow flows, with kill weight mud to prevent underbalance when the well is circulated prior to cementing.

It is highly recommended that inner string cementing be used, either using the stab-in technique or free-hanging drillpipe as the inner string. Typically, stab-in float equipment is not used and the end of the inner-string is run to 50 to 80 ft above the casing shoe. Displacement volume is calculated to leave 40 to 50 ft of cement inside the casing.

Inner-string cementing is preferred for the following reasons:

a. Substantial contamination of cementing fluids (spacers and cementing slurries) can occur in large casing sizes using conventional cementing techniques.

b. Substantially less cement is required to provide adequate uncontaminated cement in the annulus.

c. Displacement volumes would be larger and substantially longer job times would result using conventional techniques.

d. Inner string cementing allows faster response to changing well conditions.

1. Particularly beneficial in combination with foamed cements.
2. Rapid response to flows or lost circulation.
3. Flexibility to start displacement at any point in cementing operation (based on observations at wellhead by ROV).
4. Minimizes cementing operation time—shorter thickening time for cement allows reduced wait on cement (WOC) time.

Common cementing best practice is to circulate the hole a minimum volume of one bottoms-up once casing is on bottom. This is to ensure that cuttings have been removed and that maximum circulatable hole volume has been achieved. However, cementing large diameter bore holes containing kill/spotting fluids may preclude this practice in favor of commencing the cementing job as soon as possible after the casing is in place. Additional circulation will not only require large volumes of kill-weight fluids, but also increase the risk of further well bore washout in the unconsolidated formations. The use of inner string cementing allows the commencement of cementing with the minimum amount of fluid circulated once the desired circulation volume has been accomplished and flow conditions verified.

The circulation rate required to accomplish removal of the mud can be modeled using software available from cementing companies. These modeled rates should be used for the circulation prior to and during cementing. The software should also be used to determine maximum rates allowable before friction pressures are great enough to cause “fracturing” of weak formations.

9.2 CASING HARDWARE/EQUIPMENT

9.2.1 Automatic Fill Floats

Automatic fill float equipment can be used to reduce the surge pressures when running casing. These devices restrict the flow and care must still be taken to ensure that casing is run at a controlled rate to avoid breaking down weak formations. When running an automatic fill float, the casing will become filled with the same fluid that is in the wellbore.

When casing is landed, the automatic fill valve is “tripped” to convert it to a check valve.

9.2.2 Upjet shoe

An upjet shoe can be used to assist in forcing flow all around the shoe and to minimize additional hole erosion at the shoe.

9.2.3 Centralizers

Centralizers are the single most important piece of casing hardware for the conductor and surface casing cementing operations. Centralization of the casing improves displacement efficiency.

Centralization or “stand-off” of casing is better in vertical well sections and with hole sizes closer to the casing size. Even in the case of washed out hole sections, centralizers will provide some standoff if the well is close to vertical as the lateral forces are minimal. Simulators may be used to model and optimize the standoff achieved and its relation to the mud removal process.

9.2.4 Mechanical Isolation Devices

Mechanical isolation devices are sometimes used to supplement the cement job. While mechanical isolation devices may prevent flow from occurring past their position, they may encourage annular influx in the annulus below. Care must be taken in the placement and activation timing since activation isolates the annulus and formations below from the hydrostatic pressure above the device. Subsequent deterioration of the hydrostatic pressure below due to fluid loss and cement shrinkage can result in a fluid or gas influx below the device. Cement slurries placed below an isolation device may require modification to prevent such an influx.

Examples of isolation seals in wellhead are shown in Appendix G.

Inflatable/external casing packers are NOT recommended for open-hole inflation to control flows. Reasons are:

a. Sufficient stress against low strength formations cannot be achieved to provide an effective seal.

b. Inflation of the packer against the formation may induce a fracture that can initiate or exacerbate a flow.

c. Use of a packer to seal at the casing shoe can weaken the shoe if formation fracturing occurs.

9.3 PIPE MOVEMENT

Pipe movement is an effective technique for aiding in removal of drilling fluid, especially gelled drilling fluid or fluid that is “trapped” on the narrow side of the casing because of inadequate centralization or of inability to achieve desired flow conditions for effective mud removal. The risks of movement should be assessed against its benefit in removing mud and achieving the seal. Since the pipe must be landed at a specific point to effect the seal, pipe is commonly not moved on conductor and surface casing cemented in deep water. If pipe movement is not planned, more significance must be placed on fluid properties and pipe centralization.

10 Mud Removal and Placement Technique

10.1 GENERAL

The mud removal process is as important, perhaps more so than the actual composition of the cement slurry. Unless effective mud removal is achieved, even the most exotic cement slurries cannot form an effective seal.

10.2 DISPLACEMENT OPTIMIZATION

10.2.1 General

The critical variables and practices affecting displacement of one fluid by another are well known in the industry. The following are elements of displacement optimization design.

a. Fluid mechanics/fluid flow.
b. Fluid rheology/rheological relationship between fluids.
c. Flow time with the desired flow characteristics.
d. Density relationships.
e. Mechanical factors.
   1. Centralization of casing.
   2. Pipe movement.
f. Chemical compatibility between fluids.

Application of all of these variables/practices to maximize displacement efficiency is not possible in many cementing operations. Compromises may be required depending on the well conditions, available equipment and materials, and operational or logistical constraints. Use of these criteria should be maximized to minimize the risk of zonal isolation failure.

10.2.2 Fluid Mechanics, Fluid Flow and Rheological Relationships

Although turbulent flow is the most desirable flow regime for removal of drilling fluid ahead of cementing, in most scenarios involving the potential for shallow water flow, turbulence is very difficult to achieve. In that case, an alternative technique using engineered laminar flow regimes that has been shown to be effective in physical and computer modeling should be used.

In a laminar flow regime, displacement efficiency can be significantly improved if the frictional pressure of the displacing fluid is 1.2 to 1.3 times (20 to 30% higher than) the frictional pressure of the fluid being displaced. The displacement efficiency is also improved if the density difference between fluids is increased as well. Density differentials should be planned to achieve the maximum stress on the fluids to be removed from the well within the constraints of fracturing pressure.

Consideration should be given to the displacement mechanics in all parts of the annulus, including on the narrow side. Again, unless the forces are correct for removal of the drilling fluid in all parts of the hole, including the narrow side, an effective seal cannot be achieved.

For this reason, the use of centralizers to achieve standoff of the casing from the borehole wall is necessary to optimize mud removal. This optimization is done using the drilling fluid properties as well as hole geometry, pipe and cementing fluid properties. Cementing companies use software to accomplish this integration of centralization with the cementing process. Computer simulations to model the displacement process should be done using conditions which are as near to those existing downhole as can be determined. Design for mud removal and placement of centralizers should include all sections requiring isolation, especially the SWF zone.

These guidelines provide flexibility in the combination of flow rate and rheological properties of the fluids to allow them to be adapted to a wide range of conditions.

10.3 SPACERS/FLUSHES/SWEEPS

A variety of spacers having a broad range of chemical compositions and physical/rheological properties are available. The spacer should be selected to maintain well control and wellbore stability, to enhance displacement efficiency, and separate incompatible fluids.

Special fluids which aid in removal of and separation of the drilling fluid from the cement are necessary for proper sealing in the annulus. These fluids may be as simple as sea water or sea water with mud dispersants or complex mixtures of water, surfactants, wetting agents, gelling agents and solids for the desired density. In all cases, environmental consideration must be given to selection of spacer fluid and components to ensure minimum hazard to marine life.

The more complex spacers may be required to remove the kill or drilling fluid in the hole at the time of cementing. These spacers may require a gelling agent to achieve the required friction pressure or shear stress to properly remove the mud and gelled material in the annulus and to suspend solids if a weighting agent is required to achieve the proper density. Surfactant may also aid in dispersing the drilling fluid at the interface with the spacer or to water wet downhole surfaces if non-aqueous drilling fluids have been used.

The properties of these spacer fluids should be considered, both in the mud removal process, and in the process of displacement by the cement (the cement must remove this spacer for the cement to be able to effect a seal). Additionally, to accomplish these goals, the fluids should be tested for compatibility with each other (under the temperatures encountered in the well). If non-aqueous fluids have been in the well, the spacers should be tested for the ability to produce a water-wet condition on the surfaces for the cement to be able to make an adequate seal.

Consideration should also be given to the location of returns. Density and fluid composition constraints are different when returns are taken to the seabed as opposed to the rig when a riser is installed.

Recommendations for selection and application of spacers are summarized below:

a. Low viscosity, lightweight spacers are generally more effective for increasing displacement efficiency in turbulent flow than viscous weighted spacers. Care must be taken when using lightweight fluids to ensure that their lower density will not result in an underbalanced condition which could allow flow to occur.

b. Higher viscosity, weighted spacers to meet mud removal and well control requirements.

c. Foamed sweeps/foamed spacers (weighted or unweighted) can increase displacement efficiency. Base fluids for these spacers are higher density (13 lb/gal – 15 lb/gal). Nitrogen and surfactants are added to create a foamed fluid with the proper density (typically, 8 lb/gal – 12 lb/gal).

d. Reactive materials (sodium silicate, etc.) can be incorporated into most types of spacers.

1. Aids cement-formation (filter cake) bonding.
2. Reduces loss of filtrate or whole fluid (lost circulation) to the formation.
3. Impairs formation and reduces potential for flow.

10.4 PUMPING SCHEDULES/SIMULATIONS

Computer programs for simulation of cementing operations are essential tools for the design of cementing operations. Computer simulations should be performed for cementing design to:

a. Evaluate the optimum combination of practices, fluid properties and fluid volumes to obtain maximum displacement efficiency.

b. Determine pressures in the wellbore during the cementing operation are safely within the pore and fracture pressure margins.

c. Determine sensitivities of well control, wellbore stability and displacement efficiency to variations in fluid volumes, densities, rheological properties and hole size, etc.

d. Computer simulations using accurate well and fluid data should be used to determine centralizer placement, volumes (annular column lengths), fluid schedules, pump rates for the cementing operation and to qualitatively assess displacement efficiency. The simulation should also be used to determine if ECD at planned circulation rate will break down weak formations.

11 Cement Slurry Design

11.1 GENERAL

Flow channels in and around the cement may be formed as a result of one or more of the following:

a. Poorly designed, executed or problematic primary cementing operations—improperly mixing cement can result in compromised cement slurry and setting properties. If pumped at incorrect rates, the fluids may be ineffective in removing the wellbore fluids ahead of the cement, resulting in uncemented flow channels.

b. Flow occurring during cementing operations—flow which occurs while the cement is being pumped in place will lighten the cement, possibly resulting in inadequate pressure to further control flows and will result in cement which does not have the desired set properties (setting behavior including early and ultimate strength development).

c. Flow occurring after cement is placed but before it has set and hardened—flow into the cement will create flow channels through which the flowing formation can continue to flow and cause loss of structural integrity in the well. It can also result in reduced stresses in the flowing sands, resulting in increased stresses on casing in existing or future wells nearby. Damage to casing and to surface equipment can result.

Geopressure can be transmitted up the wellbore through the channels and, if trapped by a seal (mechanical isolation), can charge or fracture a formation of lower pressure or strength. If the fracture extends beyond the casing, it could eventually reach the surface and cause broaching around the conductor or structural casing strings. Failure by this mechanism may occur long after the casing has been cemented. Fractures can also extend to neighboring wells and create a flow path to the seafloor. This has occurred with neighboring wells as close as 20 ft and as far apart as 200 ft.

Since the structural, conductor and surface casing strings are the foundation upon which the rest of the well depends, obtaining a quality cement job is critical to successfully drilling the well to the target objective.

Fundamental functional requirements for both *lead* and *tail* cements include:

a. Stabilize the wellhead and reinforce the casing string against bending forces.

b. Provide additional axial support for well loads and resist buckling and wear of the casing. This includes loads from production risers tied back to surface structures, production loads from fluids and thermal stresses.

c. Achieve a competent hydraulic seal that will not allow migration or flow of fluids between formations, through the cement sheath or outside the casing/cement sheath to shallower casing shoes or surface.

d. Provide long-term durability of the hydraulic seal and structural support during cyclic loading from thermal, pressure, mechanical and geomechanical forces. Stress changes/cycling include the following:

1. Pressure testing casing shoes.
2. Pressure cycling.
3. Load cycling (production, storm, etc.).
4. Thermal cycling—Temperatures in tubulars at the mud line can range between 100°F and 180°F or higher, depending on bottom hole temperature (BHT) and production rate.
5. Reservoir compaction can add additional stresses on tubulars and cement, even well outside the flowing interval.

Cement properties necessary to meet these objectives include:

a. Rheological properties that aid good displacement efficiency.

b. Hydrostatic pressure control.

c. Fluid loss, free water and sedimentation control.

d. Rapid set and adequate short term and ultimate strength development.

e. Long-term sealing (bonding/ductility).

1. High shear strength.
2. Non-brittle (ductile) properties.

f. Ease of design and modification.

The first requirement of the cement is to effectively displace the fluids ahead of it. This means that the cement must displace the "spacer" or "preflush" which is used to aid in removal of the drilling fluid and prevent mixing of the drilling fluid and the cement. To do this, the cement must have favorable rheological properties for removal of the spacer or preflush. This implies a hierarchy of properties between the drilling/pad fluid, spacers and cement slurries.

The most important property of the cement is its ability to form a long-term seal. Permeability and mechanical durability play a key role in the seal (SPE 20453, SPE 72059). Normally, low and acceptable permeabilities are maintained by cements with low mix water ratios. Permeability is higher for high mix water ratio cements because there is excess water over that which is consumed in the hydration reaction.

Additionally, the durability of the cement should be enhanced by the use of materials which impart good "toughness" properties. Toughness is enhanced by the use of special materials mixed with the Portland cement or by the use of gasified cements.

The long-term durability of the cement and the seal is dependent on other chemical factors as well. Consideration should be given to the nature of exposure of the cement to fluids in the formation and wellbore and ensure that there will be no reactions which can damage the seal.

Another requirement of the cement is the ability to resist or prohibit invasion by formation fluids during its setting. The most vulnerable period is immediately after placement and prior to the setting of the cement. It is during this time that the cement, while developing gel strength, becomes self-supporting and loses its ability to transmit hydrostatic pressure. This hydrostatic pressure loss is responsible for the well reaching an under balanced condition which can lead to fluid invasion.

To prevent formation flows or fluid intrusion, a number of strategies have been developed. These include the use of special slurries with physical and chemical properties that inhibit or block the invasion of fluid. Another method is the use of special slurries that control gelation of the cement until it is on the verge of setting or that set very early and rapidly. A further method is the use of slurries that are compressible by the incorporation of a gaseous component. The gaseous component can be either a gas that is developed internally in the slurry due to a chemical reaction, or it can be a gas that is introduced into the slurry before being pumped into the well, that is, foamed. The use of gas in the slurry has the benefit of "trapping" the hydrostatic pressure of the fluids in the wellbore, thus serving as a reservoir of pressure that maintains pressure on the potentially flowing formations, while gel strength development occurs.

Care should be taken when designing the gas ratios of foamed cement slurries to meet the requirements of low permeability, pressure maintenance and the durability mentioned earlier. Modeling and lab testing may be required to show that permeability values are acceptable.

One method of minimizing the vulnerability of the well to pressure losses by gel strength development is to minimize the time that an underbalanced condition exists before the cement has developed sufficient strength to resist invasion by the well fluids. A "Critical Gel Strength Period" describes this time. This Critical Gel Strength Period is defined as the time required for the cement to progress from the "Critical Static Gel Strength" to a static gel strength of 500 lb/100 ft^2. The Critical Static Gel Strength is the gel strength of the cement that results in hydrostatic decay producing an exactly balanced condition in the well.

The Critical Static Gel Strength (CSGS) can be computed by:

$$CSGS = (OBP)(300)/(L/D_{eff})$$

where

OBP = Hydrostatic overbalance pressure (psi),

300 = conversion factor (lb/in.),

L = Length of the cement column (ft),

$D_{eff} = D_{OH} - D_c$

where

D_{OH} = Diameter of open hole (in.)

D_c = Diameter of casing (in.)

The Critical Gel Strength Period is measured using a device that allows measurement of gel strength under pseudo-static conditions and wellbore temperature and pressure.

An additional property of the slurries used to control the loss of hydrostatic is low fluid loss. Low fluid loss slurries lose less volume to surrounding permeable formations. This helps to reduce hydrostatic pressure loss that is actually a combination of gel strength development and volume loss. Fluid loss additives should be selected which meet the fluid loss requirement and yet do not contribute to excessive gel strength development.

Other properties of the cement which are important are the thickening time and slurry stability. The thickening time must be adequate for placement of the slurry but not excessive. If the thickening time is excessive, the setting of the cement will be delayed, thus extending the time when the cement is vulnerable to invasion by formation fluids. Slurry stability is characterized by water or particle segregation. The free fluid must be maintained at a low value as fluid separation from the cement slurry can result in a highly conductive channel that will prevent an effective seal. Slurry stability can be controlled by optimization of the water/cement ratio or by the use of additives.

If production temperatures exceed 230°F, consideration should be given to potential strength retrogression caused by changes in the cement hydrates. Above 230°F, calcium silicate hydrate gel is unstable and converts to other calcium silicate hydrate forms that are lower in strength and higher in permeability. The degree and rate at which strength retrogression occurs increases with increasing temperature. Note that this conversion can occur at any time in the life of the cement, even years after its initial setting. This conversion is normally controlled by the addition of crystalline silica to the cement, which favors calcium silicate hydrates with better strength and permeability characteristics. If, based on computer modeling, there is danger that production may expose the cement in shallow casings to such high temperatures, consideration should be given to the ability of the cement formulation to control strength retrogression.

When narrow margins between pore pressure and frac gradient exist, cementing operations should be designed to mitigate lost circulation or reduce lost circulation potential and to remediate lost circulation induced during cementing operations. This implies limits to the density at which the cement is placed in the well.

11.2 BASE CEMENT COMPOSITIONS

A number of cementing materials/compositions are effective in meeting the objectives of cementing the shallow casings where there is risk of SWF (SPE 62957, SPE/IADC 67774, OTC 8304, OTC 8305, OTC 11977). These include, but are not limited to:

a. API and ASTM cements, in many cases containing accelerators to speed up hydration and compressive strength development.
b. Special types of cement such as manufactured lightweight cement.
c. High aluminate cements and blends.
d. Blends with micro-fine cements.
e. Blends with calcium sulfate hemi-hydrate.
f. Blends with proprietary high performance additives.

In essence, nearly any cement can be formulated to achieve the properties required for placement and creating and sustaining a seal in the deep water environment. Experience has shown API Classes A, C and H or ASTM Types I, II or III cements are applicable for many SWF applications. Any of these may include other special additives to enhance the properties of the cement formulation as discussed previously. High performance blends may be justified/required for more extreme shallow water flow situations—particularly in multi-well template developments to maximize the probability of success.

Other cement formulations can be made to accomplish many of these same objectives. Materials can be added which allow mixing with higher water concentrations (additives prevent water/cement separation) or which provide reduced densities without additional water (such as hollow microspheres). It is common that these two techniques are used together to provide the best combination of properties. Generally, these types of cement formulations have limited flexibility to adapt to changes in well conditions prior to and during cementing operations.

Compressible, gas-entrained cements offer some advantages over non-compressible cement slurries. Their main advantage is that they provide some internal pressure maintenance to combat volume losses that occur prior to cement setting. Therefore, they can delay the loss of hydrostatic pressure leading to underbalance and potential flow. Bond strength and ductility may be improved. One method of introducing gas into the system is the use of gas-generating materials. These materials produce gas (typically hydrogen or nitrogen) in-situ in the cement slurry. However, flexibility to adapt these cement formulations to significant changes in well conditions is limited, depending on the method of introducing the gas-generation additives. For example, liquid additives offer more flexibility than dry-blending. There may be some limitation to the use of this type additive due to reduced activity at low-temperatures.

Any of these cements may be foamed. Foamed cements are the highest performing cements for low temperature and applications requiring potential flow control (IADC/SPE 59136, IADC/SPE 59170, SPE 62957, OTC 8304, OTC 8305, OTC 11976). The performance benefits of foamed cements are due to the following:

a. Compressibility of the gas in the slurry retains high pore pressure in the cement column to resist flow into and through the cement.

b. Base cement is mixed at a "normal" or a lower water/cement ratio.

c. Density is reduced by the addition of a gas which has no effect on cement hydration, setting time and strength development. The gas has a much lower specific gravity than lightweight additives used in non-compressible lightweight cements, thus allowing lower density cement with less sacrifice of strength.

d. Foamed cement provides enhanced fluid loss control (three-phase system).

e. Rheological properties of the foam are beneficial to displacement in large annuli.

f. Faster set and early compressive strength development.

g. Higher ultimate strength.

h. Higher shear strengths.

   1. Greater axial load bearing capacity.
   2. Better hydraulic seal between cement-pipe and cement-wellbore surfaces.

i. Durability is better than conventional cements due to the cellular nature of the cement matrix (although other methods are available to produce highly durable cements).

j. Flexibility to alter slurry design (density) throughout the cementing operation.

   1. Logistical advantage for operations.
   2. Single blend or material can be fine-tuned to optimal density just prior to use based on the actual well conditions known only after drilling the interval.
   3. Less sensitivity to density variations. Cement density can vary over a range of 5 lb/gal – 6 lb/gal, with minimal effects on the properties of the cement.

11.3 CEMENT FORMULATION AND PROPERTIES

Selection of the cement formulation should be based on performance properties required for the conditions of the well. Any material meeting these criteria is acceptable regardless of base material and basic fluid type (foamed, unfoamed, gas-entrained/gas-generating). This provides options to balance logistics, operational issues, and cost to meet required performance objectives. Note that in many cases, the potential for flow is not fully understood and that the most stringent criteria for cement slurry composition and cementing technique should be employed. Foamed cement provides the best combination of cement liquid and set properties for this situation.

Cementing service companies can provide examples of slurries that have been demonstrated to be effective in providing a seal and preventing shallow water flows.

In general, the following guidelines can be used when there is potential for shallow water flows. As this is a matter of selecting the appropriate slurry to control flow, which if left uncontrolled can have catastrophic results, the proper selection of slurry formulation must depend on the risk of and potential severity of the flow. Uncertainty should lead the engineer to favor the more stringent conditions.

a. *Free Fluid and sedimentation control*: Degree of control dependent on degree of risk of shallow water flow.

b. *Fluid Loss*: Degree of control dependent on degree of risk of shallow water flow.

c. *Critical Gel Strength Period** (Measured at temperature of the SWF zone.): Minimized to the extent possible, preferably less than 45 minutes.

**Critical Gel Strength Period*—the time between the development of critical static gel strength and 500 lb/100 ft^2 when measured at 0.2°/ minute (or at shear rate of < 10^{-3} sec^{-1}) on an apparatus designed to make this measurement under simulated downhole conditions. The gel strength may also be determined using pressure drop measurements or ultrasonic correlations. It cannot be determined using a consistometer or a standard rheometer.

The Critical Gel Strength Period must occur after mixing and pumping stoppages have been completed (such as dropping a wiper plug).

d. *Strength development*: Adequate at low temperatures based on current engineering knowledge and the operator's discretion.

Cement strength tests should include conditioning according to schedules simulating cement mixing and placement followed by curing at temperatures simulating the static placement and gradual return to formation temperature. Pressure can have significant effects on the development of strength. Curing for strength determination should be at pressure as near as possible to that found in the well. The heat of hydration effects on strength development should be considered as well. This effect can result in much earlier strength development and consequently, a much shorter WOC time with consequent cost savings.

When used for strength determination and WOC times, ultrasonic, non-destructive test data must be based on correlations to cube crush strength values and strength development times for similar types of slurries. This is especially true for slurries at very low densities, those containing special high-performance, lightweight extenders and gas-containing slurries. The degree to which these properties are controlled should be based on perceived degree of risk and latest experience in the area.

One set of properties which was used for developing cement systems in a joint industry project is:

a. Thickening time—Appropriate for operation with lead slurry longer than tail slurry.

b. Fluid loss—Less than 50 mL/30 min, API.

c. Free water—Zero to trace with cylinder inclined at 45° angle.

d. Rheology—Must be easily mixed and pumped.

e. Compressive strength—500 psi in less than 24 hours at 50°F and 500 psi in less than 18 hours at 65°F.

f. Transition time—Less than 45 minutes for both lead and tail.

All of above properties should be determined at simulated placement and downhole conditions. These properties may change when well conditions change and when specific slurry placement or a structural integrity analysis requires different values.

A typical cementing program may consist of *two to four cement slurries* as described in Table 1.

11.4 CEMENT DENSITY

Cement density is limited by 1) pore pressure—fracture pressure margin, and 2) density of kill/pad fluid. The effective pressure of the cement column at any depth in the annulus should be greater than the pore pressure and less than the fracture pressure of the adjacent formations. This provides some, although often limited, flexibility in densities of cement slurries used in the cementing operation. Traditional guidelines for selection of cement density are not always applicable for deepwater, SWF intervals because of the narrow pore pressure and fracture pressure margins.

The following recommendations are made regarding density selection and density hierarchy in cementing operations.

a. An increase in density for each successive fluid increases the effectiveness of displacement of each fluid (but within the limits of weak formations). Density differential between lead cement slurry and spacer or kill/pad fluid should be at least 10 percent, if possible. Note that these criteria would imply a tail cement of 14.5 lb/gal if the pad fluid is 12.0 lb/gal and there is a weighted spacer, lead slurry and tail slurry. Therefore, in many cases, these recommendations cannot be met. The density differential should be maximized within prudent limits to optimize the mud removal process.

b. Do not arbitrarily set spacer density between lead cement density and kill/pad fluid density. If necessary, consider designing fluid densities and cementing operation as follows:

1. Set spacer density equal to kill/pad fluid density.
2. Precede spacer with a lightweight, low yield point/low viscosity fluid (pre-flush) (volume determined to maintain well control).

c. If lost circulation potential is high, consider designing fluid densities and cementing operations as follows:

1. Precede spacer with a low density, low yield point/low viscosity fluid (pre-flush) (volume determined to reduce hydrostatic pressure in annulus while maintaining well control).
2. Set spacer density equal to kill/pad fluid density.
3. Set lead cement density 10 percent (minimum) higher than spacer and kill/pad fluid density when possible.
4. Mix the tail slurry at the optimum to achieve the desired mechanical properties. This may require foamed cement or solid lightweight materials.

Table 1—Typical Cementing Program

Slurry Designation	Function (General)
Lead Cement Slurry 1	Sacrificial slurry designed to be circulated out of wellbore. May be same density as kill/pad fluid. Beneficial for cementing operations where lost circulation potential is high. Beneficial if a non-settable kill/pad fluid was used.
Lead Cement Slurry 2	Primary lead cement slurry. Higher density, if possible, than kill/pad fluid. Has performance/material properties required for structural support and zonal isolation (hydraulic sealing in casing x casing annulus, etc.).
Intermediate Cement Slurry	Density between that of lead cement and tail cement. Higher strength than lead cement for additional structural support. Higher performance properties for zonal isolation. Beneficial to cover flow zones, if conditions allow. Beneficial when formation fracture pressures allow intermediate density which will not support a longer column of tail cement.
Tail Cement Slurry	Highest density slurry in cementing operation. Highest strength/shear bond/zonal isolation properties to provide effective seal around casing shoe. Foamed tail cement slurry for most foamed cementing operations. May contain gas generating agents in non-foamed cementing operations.
Tail Cement Slurry 2	Unfoamed tail cement slurry for most foamed cementing operations. Unfoamed slurry should be left in the shoe track and also in the annulus around the shoe joints to provide the best support of the casing during drillout.

11.5 CEMENT VOLUMES

High quality cement from the casing shoe to the mud line is essential to provide the necessary structural support and to prevent buckling of the conductor and surface casings as well as achieve isolation.

Openhole caliper logs are not typically run in shallow intervals, particularly if there is risk of flow. A caliper can be obtained from multi-sensor resistivity logs or sonic logs obtained from logging while drilling data. General practice is to use a minimum of 100 percent to 150 percent excess over gauge hole for conductor and surface casing cementing where risk of flow is low. If flows have occurred during drilling, significant washouts may have formed. In these cases, excess factors for cement may be between 200 percent and 300 percent. The quality of calipers and experience in the area should dictate the excess factor used. Regulations may specify minimum cement volumes.

Volumes of the individual stages (Lead Cement, Tail Cement, etc.) are generally determined by annular capacity, density of the slurry and maximum allowable hydrostatic pressure for the cement column.

When using the inner string method, a desirable technique to help assure proper placement of the desired slurries is to continue pumping lead slurry until returns are observed at the wellhead by ROV. When lead slurry is observed, the tail slurry is mixed and displaced.

11.6 LABORATORY TESTING AND RESULTS

Almost all properties of the cement slurry are affected by the conditions to which it is exposed. This is especially true of those properties of a chemical nature or arising out of chemical phenomena. Slurry properties must be measured under realistic conditions of mixing, placement and curing. This means that the mixing, placement and curing of the cement should be modeled with respect to the time, temperature and pressures to which it will be exposed.

ISO/API procedures are under development for use in testing for deep water cementing conditions (ISO/DIS 10426-3 *Petroleum and natural gas industries—Cements and materials for well cementing—Part 3: Recommended practice for testing of deep water well cements*). The ISO practices specify methods for testing cementing fluids for applications in deep water conditions using the standard procedures of ISO/DIS 10426-2, *Petroleum and natural gas industries—Cements and materials for well cementing—Part 2: Recommended practice for testing of well cements* and API RP 10B *Recommended Practice for Testing Well Cements*. The ISO standards are currently drafts. They are expected to be available in 2003.

Test methods must be modified to simulate the anticipated conditions so that the properties of the cement slurry designed and tested in the laboratory are most like the properties of the slurry when placed in the well. As discussed previously, temperatures to which fluids will be exposed during cementing of a well in deep water will be lower than in conventional land and shallow water wells. Consequently, API schedules are invalid and should not be used (IADC/SPE 39315). Temperatures must be determined using the variety of tools which are available and appropriate pressure / temperature schedules constructed for testing of cementing fluids. (See discussion of temperature determination in 11.7.)

The following tests should be performed for each cementing operation:

a. Thickening time (base slurry if foamed cement).
b. Critical gel strength period tested using a gel strength measurement.
c. Compressive strength.
   1. Non-destructive ultrasonic testing is preferred (except for foamed cement which cannot be tested with this method). Additionally, the procedure is highly inaccurate at low strengths. When tested on the base slurry of foamed cement, a strength development profile is obtained which can be used with correlations for the foamed cement to determine WOC times.
   2. Crushed cube strengths should be used for foamed cement and for anticipated low strength conditions (less than 250 psi). Alternatively, historical correlations of foamed cement strength to non-destructive ultrasonic tested strengths of base slurries may be used.
   3. Lead cement at mud line temperature.
   4. Tail cement at the shoe.
   5. Cement at the anticipated flow zone.
d. Free fluid (base slurry if foamed cement).
e. Slurry sedimentation (base slurry if foamed cement).
f. Foam stability (if foamed cement is used).
g. Rheological properties.
   1. All fluids.
   2. Compatibility between spacer and kill/pad fluid.
   3. Compatibility between spacer and cement.
h. Sensitivity testing (when a database of slurry and additive variability is not available).

11.7 TEMPERATURE DETERMINATION

Although pressure has a marked effect on cement setting behavior, temperature is by far the strongest external factor affecting cement setting. Standard tables are unacceptable for determining temperatures encountered in wells drilled in deep water environments. The temperature in the ocean and at the sea floor is much cooler than surface temperatures, thus the cement is first exposed to an inverse temperature gradient as it is being circulated down the drill pipe. Additionally, the temperatures of the formations near the sea floor are very cool and must be accounted for in the design of slurry placement and curing. Also, the conditions while mixing the cement on the surface can vary seasonally. For these reasons, the temperatures must be measured and/or modeled in simulators so that the appropriate temperature schedules can be computed and used when testing slurries for application in deep water conditions (IADC/SPE 39315, SPE/IADC 57583, SPE 49056, SPE 56534, SPE62894).

Other significant factors are: 1) the effect of heat of hydration of the cement on the temperature of fluid in the casing, and 2) dissipation of this heat to the surrounding formation. The amount of heat energy generated depends on the mass of cement, maximum temperature of hydration and duration of the exotherm (SPE 56534, SPE62894).

Some of the necessary data can be gathered using tools available in the industry:

a. Geotechnical borehole data.
   1. Static temperatures.
   2. Characterization of geothermal gradients at shallow depths below the mud line. (Typically < 1000 ft below mud line).
b. Wireline log data.
   1. Static temperatures.
   2. Temperature profiles in the wellbore during cement setting and hardening.
c. Pressure while drilling measurements.
   1. Circulating temperatures.
   2. Static temperatures.
   3. Temperature profiles in the wellbore during cement setting and hardening.
d. Temperature Sub Data.
   1. Circulating temperatures.
   2. Static temperatures.
   3. Temperature profiles in the wellbore during cement setting and hardening.
e. Other Tools (MWD, DataTrace Tools, circulating pellets, etc.).
   1. Varied depending upon tool.

Care must be used to ensure information from any of these tools is accurate by:

a. Selecting the temperature sensor appropriate for conditions (temperature range, location, etc.).
b. Calibrating the temperature sensor prior to use (or checking calibration).
c. Setting the sampling rate for the tool that is appropriate for conditions.
d. Verifying the sensor is properly positioned in the flow stream to be measured.
e. Giving consideration to factors affecting the reliability of the measurement with respect to the desired environment.

12 Pre-job Preparations

Successful cementing depends on a number of practices that are conducted prior to any cementing job. These include bulk blending, sampling and testing, materials inventory, equipment maintenance and calibration and standards of rigging up to perform the job. These are discussed in Appendix E.

13 Health, Safety and Environment

Appropriate standards of safe operations should be established for all cementing operations. If the service company does not have them, a standard should be written to address the HSE concerns of working in the deep offshore environment. Standards of all companies involved (operator, drilling contractor, service companies) must be adhered to. In the case of the use of energized fluids, additional standards pertaining to the unique HSE concerns of these kinds of fluids should be adopted and adhered to. API RP 75 *Recommended Practice for Development of a Safety and Environmental Management Program for Outer Continental Shelf (OCS) Operations and Facilities*, can serve as a guide to developing a safety and environmental program.

All environmental guidelines must be adhered to. This includes, but is not limited to, discharge of fluids to the seafloor or ocean surface and dust to the atmosphere. Fluids that produce a sheen on water, or are not within the current guidelines for marine toxicity and biodegradability must be contained and disposed of by appropriate methods.

14 Cement Job Execution

14.1 CEMENT MIXING AND DISPLACEMENT PARAMETERS

Cement mixing should be done in such a way that good control of slurry properties, especially density, are achieved. It is most important that the density is correct, as this affects slurry and set cement properties. The rate of mixing is less important. However, if cement is being circulated downhole while mixing continues, consideration should be given to the viable mixing rate in computing displacement mechanics. If the two are incompatible, then adjustments should be made to achieve the desired objectives of both. In some cases, this may mean that a batch or semi-batch mixing process is required. That being said, consideration must also be made to surface constraints such as deck space and variable deck loading.

When foamed cement slurries (gasified cements) are being used, the mixing operation becomes even more critical. For foamed cements, not only must the base cement slurry be mixed to acceptable standards, but also the gas itself and foaming and stabilizing surfactants must be mixed in the proper proportions to achieve the ratios that are desired downhole. This implies the precise control that can only be achieved by using process controlled mixing systems for the introduction of the surfactants and gas to the previously mixed base slurry. Although not essential, process controlled base slurry mixing can make the mixing operation much more reliable.

Once the slurry is mixed, it should be pumped downhole using the rates determined by computer simulations for the mud removal process. The correct rates should be maintained at the downhole interface between the respective fluids (drilling fluid, spacer, cement) so that the correct flow regime and displacement criteria are met according to the design developed by the cementing engineer. Due to "u-tubing" effects caused by the hydrostatic imbalance between the heavier fluids in the pipe and the lighter fluids in the annulus, as well as expansion and/or compression of foamed fluids, flow in the pipe and in the annulus may be at different rates than that which is being pumped into the well. This effect should be accounted and compensated for to ensure that the flow rate in the annulus is correct for the displacement mechanics required to meet the mud removal and sealing objectives.

If pipe can be moved (either rotation or reciprocation) while displacing cement, mud removal and cement placement will be enhanced. If pipe movement is employed, care should be taken to ensure that excessive forces aren't generated that could damage the casing, or cause undue surges on the formation that could cause losses.

Pipe movement should be stopped at or just prior to the end of the cement job. Just prior to ending the displacement of the cement, the pipe should be landed or prepared for landing in the proper position to achieve proper support and sealing if those features are part of the casing scheme.

14.2 DATA ACQUISITION

Electronic data acquisition is recommended for all cementing operations. As a minimum, pressure, cement density (preferably at high pressure line downstream of cementing pump), and fluids pump rate should be recorded. For foamed cementing operations, nitrogen flow rate, nitrogen injection pressure, nitrogen temperature and foamer flow rates should also be recorded.

It is beneficial to record data for all variables/components of the cementing operation. This includes flow rate of mix water to the mixer, temperature of cement slurry in the mixing tub, flow rates of all liquid additives, total mass of cement used for the cementing operation, in-line viscosity of fluids, etc.

14.3 ON-SITE FLUIDS TESTING

Testing and recording of data from fluid samples obtained during the cementing operation may be performed. Special equipment and testing skills are required for the tests to be valid and useful. These requirements make it impractical to perform on-site tests in most cases. Dry samples obtained at the rig and tested at the land base can provide meaningful results for thickening time and compressive strengths. Rheological properties and compressive strength (non-destructive ultrasonic testing) are particularly beneficial. Rheological properties of field samples should be compared with pre-job laboratory data. For fluids that are batch mixed, properties may be adjusted to meet design specifications (lab data) prior to cementing or placement simulations may be re-run. The pumping schedules may be adjusted based on the placement simulation or contingency plans may be implemented. Non-destructive, ultrasonic compressive tests can be used for determining waiting-on-cement (WOC) time (see 16.4).

Thickening time tests can be beneficial if modification of cement thickening time is required due to changing well conditions. These can be done best at land base with samples obtained during load-out or when the blend is transferred to the rig. Thickening time tests of cement samples taken during the job provide limited information to impact the results of most cementing operations.

15 Additional Considerations and Procedures

15.1 CEMENTING WITH A RISER INSTALLED

Some considerations when cementing with riser installed include:

a. Bottom hole circulating temperature (BHCT) will be different than when taking returns to the sea bed. This should be accounted for in temperature simulations to construct cementing temperature schedules for testing.

b. Low mud line temperatures and temperatures in the riser will have effects on viscosities of fluids and consequently on friction pressures and carrying capacity of those fluids.

c. Annular velocity will be different in the drillpipe/riser annulus than in casing/casing annulus. This can lead to inability to carry cuttings to surface.

d. Hydrate decomposition due to heat generated by cement hydration may lead to methane migration to and hydrate reformation across wellhead equipment, making operation, including emergency disconnection, difficult.

e. Cement volume miscalculation may lead to placement of cement in the riser. This can lead to problems in the wellhead if not properly cleaned out.

f. Hydrostatic pressures due to drilling fluids, spacer and cement in the riser can lead to lost circulation.

g. Plans must be developed to clean cement and spacer out of the riser.

h. Circulation of energized fluids into the riser and to surface must be considered and plans to deal with them must be in place.

15.2 CONTINGENCY PLANNING

Each cementing operation should have contingency plans for critical elements of the operation. Some critical elements are the same for all operations. Critical elements of each cementing operation should be identified during the design phase. Contingency plans should be formulated and included in the cementing program for each of these elements. In some cases, alternative designs may have to be prepared if well conditions or operations require.

A partial list of common elements of a cementing operation that may require contingency planning is provided below.

a. Flow.
   1. Before start of cementing operations.
   2. During cementing operations.
   3. After cementing operations.
b. Lost Circulation.
   1. While running casing (prior to the start of cementing operations).
   2. During the cementing operation.
c. Equipment Malfunction.
   1. Loss of automation on cementing unit.
   2. Loss of automation on nitrogen unit.
   3. Failure of flow meters/density meters.
   4. Loss of liquid additive system.
   5. Incorrect metering of additives.
   6. Leaks.
   7. Bulk cement flow interruptions.
   8. Mix water delivery interruptions.
   9. Failure of radio communications.
   10. Failure of ROV.
   11. Failure of subsea wellhead equipment.
   12. Extremely early cement returns (indicator of cement channeling).

16 Post Cementing Operations

16.1 POST-JOB ANALYSIS

Post-job reconciliation and material balance is one part of the post analysis. It should be used with other data from the job and an analysis of the results to complete a database of shallow flow completions. If required, remediation should be planned based on this analysis and future jobs in the same flow zone or in other shallow water flow scenarios planned based on the results and post-job analysis/database. Sharing of post-job analysis data between operators will help in planning for future operations in the same or similar shallow water flow zones.

16.2 ANNULAR SEALING

Many casing strings set in deep water wells have built-in sealing mechanisms. The appropriate casing landing and sealing operations must be planned for and accomplished as soon after cement placement as possible. The seals should be cleaned out (see below) and engaged as soon after cementing as possible, but a bypass should be left open to allow full hydrostatic of the ocean to be transmitted to the wellbore for non-foamed slurries. The bypass can be closed after the cement has had time to develop the required strength across the potentially flowing zones. For foamed cement, the seals may be set and the bypass closed.

Movement of the casing in the *gelling* cement can lead to improper sealing by the cement against the casing (micro-annuli). These micro-annuli can allow fluids to leak to adjacent or distant formations or to the surface, causing irreparable damage.

16.3 CLEAN-OUT/REMOVAL OF EXCESS CEMENT

When circulated to the wellhead, cement must be cleaned out of the seals. Water containing a cement retarder is used to flush any cement from the seal area. This requires a means of circulating through the seals and through the casing valve. After cleaning them out, the slips and packoff are set and the casing valve closed. This operation can cause sufficient loss of hydrostatic pressure in the wellbore that flow is initiated. In such a case, a contingency for controlling the flow must be in place. If a BOP is in place, control can be by the BOP. The timing of the cleanout must be such that the cement has not set in the wellhead and preferably after there is adequate strength across the SWF zone to prevent flow.

16.4 WAITING-ON-CEMENT (WOC) TIME

Waiting-on-Cement (WOC) times are used to determine the time to resume operations. This can include installation or removal of wellhead equipment, riser, pressure testing casing, drilling out cement, or testing casing shoe. Care should be exercised in selection of WOC time to provide optimum cement properties for subsequent operations. Loads that impart shearing to the cement as it is setting (approaches initial set) may significantly affect the quality of the seal. Allowing high compressive strength to develop prior to pressure testing can increase the potential of shear bond failure and hydraulic seal failure during the pressure test (see subsequent discussion).

After landing and cementing the casing, movement of or pressuring the casing should be avoided until the cement has developed adequate strength for support of the casing. This is generally accepted to be 100 psi compressive strength (under in situ conditions). Across the potential SWF zones, WOC until 100 psi is achieved under in-situ conditions. When ultrasonic strength devices are used, a clear indication of strength development (cement hydration) can be used. When this condition is met, strength is adequate for all operations with the possible exception of pressure testing casing and drilling out the shoe. Pressure testing the casing and drilling out the shoe should be delayed until the cement at the shoe has reached 500 psi compressive strength.

Methods for determining WOC time include determination of strength development from laboratory tests, on-site strength testing, or evaluation of results from previous wells drilled in close proximity to the well or a combination of these techniques. The method used should depend on the risk of flow and other well parameters. Temperature logs may be run to assist in determining the tops of cement as well as the time of setting of the cement. This coupled with continuous profile of strength vs. time measured on an ultrasonic non-destructive test device can help determine when the strength criteria are met. Consideration may be given to making strength measurements on-site for determination of WOC time. The only practical method of testing on-site is the use of an ultrasonic cement analyzer. Since this device uses a correlation to compute compressive strength, care must be taken that proper correlations are available and used. In order for strength tests to be useful, temperatures must be carefully controlled to simulate placement conditions including cool-down, return to formation temperatures while static and the heat liberated during cement hydration. Computer thermal simulator models that take into account temperatures to which the cement will be exposed during placement and the heat build-up due to heat of hydration can be used. These simulators take into account the heat exchange through the sea and in the wellbore as well. (See IADC/SPE 39315, SPE 62894, SPE/IADC 57583, SPE 49056, SPE 56534).

The WOC time should be based on consideration of such factors as the certainty of knowledge of temperatures in the well, presence of gas, history of annular flow incidents in the area, the pore and fracturing pressures, the occurrence of lost returns while cementing as well as other factors (such as contamination of the cement, etc.) which may have impacted the cementing job.

At all times during waiting on cement, activities which may disturb the cement should be minimized, the well must be observed for indications of flow and well control contingencies maintained. If flow occurs, control contingencies must be executed, as appropriate.

16.5 PRESSURE TESTING CASING SHOES/ FORMATION

16.5.1 Casing Tests

Pressure testing of casing can affect the cement shear bond and zonal isolation. Pressure applied to the inside of casing produces radial expansion of the casing. Radial expansion of the casing produces compressive and tensile stresses in the cement. Regulations may require such tests and specify the pressures to be used for the test.

The pressure applied during testing of casing and casing shoes combined with axial loads can contribute to bond and zonal isolation failure in the first few pressure cycles or loadings. Further static pressure or axial load cycles can be as destructive as dynamic loading.

Cement is a brittle material and undergoes brittle failure when unconfined. Ductility is higher at lower compressive strengths shortly after placement and setting. The material properties of deepwater shallow sediments and producing formations provide low confining stresses for cements. Therefore, axial loading and pressure testing of casing can seriously damage shear bond and threaten the hydraulic sealing effectiveness of cements.

However, many cement formulations begin to display more ductile behavior as confining stress increases. Foamed cements rapidly change from brittle to ductile behavior as confining stress is applied. Further, foamed cement displays more ductile behavior at lower confining stress than most non-foamed cements. Many low density (12 lb/gal) foamed cements continue to support large loads beyond initial yield with confining stress. Testing has shown that loads were supported out to large axial strains (over 20%).

16.5.2 Formation Tests

Verifying the strength of formations and maintaining formation integrity in the interval to be drilled are necessary to be able to complete the next hole section. Regulations will often prescribe whether such tests are required, the type of test and the allowable margin between the anticipated mud weight and tested formation strength. Generally, the practice is to pressure test the formations below each casing shoe to evaluate their strength. Two methods are commonly employed:

a. Leak-off Test (LOT)
b. Formation Integrity Test (FIT)

Both of these tests are performed by pumping fluids at low rates and small volume increments over one minute time intervals until a deviation from a linear slope occurs for the pressure versus cumulative volume line. The pressure at which the non-linear slope begins is used to calculate the fracture initiation pressure and fracture gradient.

The significant differences between the two tests are: (1) point along the pressure versus cumulative volume line where the test is terminated, or (2) the maximum pressure where the test is terminated, or (3) the maximum volume pumped when the test is terminated.

Wojtanowicz in SPE/IADC 67777 describes a new theory for LOT in shallow marine sediments.

Large volumes pumped in traditional LOT can result in the creation of large fractures. In some cases, this is done intentionally to perform an extended leakoff test (ELOT) to understand far-field stresses. Continued pumping of fluids can lead to a decrease in pressure indicating unstable fracture propagation is occurring. These cause damage to the integrity of the formation and should be avoided. However, in some deep water shoe tests, many formations must be squeezed repeatedly to obtain relatively small increases in pressure integrity.

During batch setting operations, repeated drilling and cementing operations over the same depth interval within a short time frame may lead to reduced conductor/surface casing shoe integrity where wells are spaced relatively close to each other. The drop in formation strength may be a result of repeated surging and fracturing of the wellbore in cold shallow sediments that do not heal quickly.

Alternate contingency operations should be planned in the event the margin between mud weight and leak-off will not allow for batch set operations without self-induced flows to the mud line. As previously mentioned, taking a LOT past the unstable fracture propagation pressure or performing an ELOT may result in extensive fracturing which can interfere with neighboring wells.

If LOT or FIT is not adequate, perform a sealing/consolidating treatment to improve formation pressure containment strength or drill ahead without treatment, constrained by the properties of the formation. If the option to drill ahead is used, consideration must be given to setting a contingency string in a competent formation, allowing the desired LOT/FIT. This string can be a conventional casing, liner or an expandable liner. When a liner is used, well control methods during cement setting are limited when no riser is installed. Care must be taken to minimize the risk of flow and to provide contingency plans if one should occur. One method of preparing to handle a potential flow is preparing for a planned bradenhead job or a squeeze job when the liner is run. This would require the use of packer above the running tool to allow the squeeze if flow is observed.

16.5.3 Summary for Pressure Tests

Fracture testing of formations (casing shoes) or ELOT is not recommended:

a. Critical to avoid in batch set, multi-well templates.

b. LOT and FIT do not accurately discriminate between a weak formation and poor cement seal around the casing shoe.

c. LOT and FIT do not provide information about far field stresses in the formation.

d. High-volume fracture tests such as conventional formation breakdown tests should be avoided.

If LOT or FIT tests are required, recommended practices are:

a. Use modified LOT to limit fracture size and provide better information on cement quality and formation stresses.

b. The casing can be filled with fluid having the density of the required FIT. The fluid level in the casing can be observed by ROV to determine if the hole is staying full and the FIT requirement is met.

17 Remediation of Flows

Flows should be killed as quickly as possible. Sustained flows cause increased washout, instability in the formations due to changing stresses and potential damage to the well and others nearby. Action is necessary before the casing shoe is drilled out (or stopped before additional hole is drilled) as additional hole beneath the flowing zone makes placement of remedial fluids more difficult and reduces the chance of successful remediation.

Remediation of flows is difficult and one technique cannot be adopted for all cases. Materials and techniques should be chosen and applied carefully to increase the probability of success and prevent additional damage to the area around the well.

Successful remediation is possible for flows occurring after a cementing operation, particularly after the cement has set, if the flow is confined inside the casing. However, remediation must be done before drilling the next interval for the well.

If flow occurs outside the casing, the probability for successful remediation depends mainly on the source of the flow, how long flow has occurred and the amount of damage done. Flows occurring from highly pressured, well developed and connected sands are difficult to remediate. The probability of success is generally higher if the flow is drilling induced or sands are not highly charged or well connected.

If the flow is not controlled before substantial ground disturbance is observed, the well should be considered a failure and abandoned. For closely spaced wells, even contained flow can be a concern because the integrity of the flowing sand is weakened. This makes it more difficult to successfully drill the remaining wells in the template.

Some flows have been successfully remediated by squeeze cementing operations using settable spotting fluids and foamed cements. This method generally requires large volumes of fluids and may not be applicable to multi-well templates. Remediation methods using reactive fluids and in-situ polymerization of sealants formulated with monomers or resins are available.

18 Bibliography

IADC/SPE 39315
“Determination of Temperatures for Cementing in Wells Drilled in Deep Water,” D.G. Calvert, T.J. Griffin, Jr., 1998 IADC/SPE Drilling Conference, Dallas, Texas.

SPE/IADC 52781
“Shallow Water Flow Planning and Operations: Titan #1 Exploration Well, Deepwater Gulf of Mexico,” Schuberth, P.C. and Walker, M.W., 1999 SPE/IADC Drilling Conference, March 9–11, Amsterdam, Holland.

SPE/IADC 52780
“Drilling Through Deepwater Shallow Water Flow Zones at Ursa,” Eaton, L.F., 1999 SPE/IADC Drilling Conference, March 9–11, Amsterdam, Holland.

SPE/IADC 57583
“Designing Effective Zonal Isolation for High-Pressure/High-Temperature and Low

Temperature Wells," Biezen, Ewout and Ravi, Kris, 1999 IADC/SPE Middle East Drilling Technology Conference, 8–10 November 1999, Abu Dhabi, UAE.

SPE/IADC 67772
"Trends in Shallow Sediment Pore Pressures—Deepwater Gulf of Mexico," Ostermeier, R.M., Pelletier, C.D., Nicholson, J.W., 2001 SPE/IADC Drilling Conference, February 27–March 1, Amsterdam, The Netherlands.

SPE/IADC 67773
"Using Conventional and Unique Methods to Drill a Technically Demanding Shallow Flow Zone," Roller, P.R., Manger, M.D., and Drury, R., 2001 SPE/IADC Drilling Conference, February 27–March 1, Amsterdam, The Netherlands.

SPE/IADC 67774
"West Africa Deepwater Wells Benefit from Low-Temperature Cements," Piot, B., Ferri, A., Managa, S-P, Kalabare, C., Viela, D., 2001 SPE/IADC Drilling Conference, February 27–March 1, Amsterdam, The Netherlands.

SPE/IADC 67777
"Shallow Casing Shoe Integrity Interpretation Technique," A.K. Wojtanowicz, D. Zhou, 2001 SPE/IADC Drilling Conference, February 27–March 1, Amsterdam, The Netherlands.

SPE 20453 *Cement Sheath Stress Failure,* K.J. Goodwin, R.J. Crook, SPE Drilling Engineering, December 1992.

SPE 24571 *Erodability of Partially Dehydrated Gelled Drilling Fluid and Filter Cake,* K.M. Ravi, R.M. Beirute, R.L. Covington, 1992 SPE ATCE, October 4–7.

SPE 49056 *Temperature Prediction for Deepwater Wells: A Field Validated Methodology,* J. Romero, E. Touboul, 1998 SPE ATCE, New Orleans, LA, September 27–30, 1998.

SPE 56534 *Deepwater Cementing Challenges,* K. Ravi, E.N. Biezen, S.C. Lightfoot, A. Hibbert, C. Greaves, 1999 SPE ATCE, Houston, Texas, October 3–6, 1999.

SPE 62894 *The Importance of Hydration Heat on Cement Strength Development for Deep Water Wells,* Romero, J and Loizzo, M., 2000 SPE ATCE, Dallas, Texas.

SPE 62957 *Fluids for Drilling and Cementing Shallow Water Flows,* Donald L. Whitfill, James Heathman, R.R. Faul, Richard F. Vargo, Jr., 2000 SPE ATCE, Dallas, Texas.

SPE Drilling and Completions Journal
"Mechanisms of Shallow Waterflows and Drilling Practices for Intervention," M.W. Alberty, M.E. Hafle, J.C. Minge, T.M Byrd, June 1999.

SPE Drilling and Completions Journal
"Burst-Induced Stresses in Cemented Wellbores," W.W. Fleckenstein, A.W, Eustes III, M.G. Miller, June 2001.

SPE 68946 "Formation Pressure Integrity Treatments Optimize Drilling and Completion of HTHP Production Hole Sections," Sweatman, R., Kelley, S., and Heathman, J., presented at the 2001 European Formation Damage Conference, The Hague, The Netherlands, May 21–22.

SPE 71390 "New Treatments Substantially Increase LOT/FIT Pressure to Solve Deep HTHP Drilling Challenges," Webb, S., Anderson, T., Sweatman, R., and Vargo, R., presented at the 2001 Annual Technical Conference and Exhibition, New Orleans, Louisiana, September 30–October 3.

OTC 8304 "Cementing the Conductor Casing Annulus in an Overpressured Water Formation," James Griffith, Ronnie Faul, 1997 Offshore Technology Conference, Houston, Texas.

OTC 8305 "Successful Cementing in Areas Prone to Shallow Saltwater Flows in Deep-Water Gulf of Mexico," D.A. Stiles, 1997 Offshore Technology Conference, Houston, Texas.

OTC 10728 "Revised MMS Regulations on Shallow Geohazards in the Gulf of Mexico," Kent E. Stauffer, Adnan Ahmed, Robert C. Kuzela, Michael A. Smith, 1999 Offshore Technology Conference, Houston, Texas.

OTC 10758 "Ursa TLP Well Systems," J.R. Carminati, L.F. Eaton, K.A. Folse, R.F. Sokoll, 1999 Offshore Technology Conference, Houston, Texas.

OTC 11971 "Shallow Water Flows: A Problem Solved or a Problem Emerging," Mark W. Alberty, 2000 Offshore Technology Conference, Houston, Texas.

OTC 11972 "Dealing with Shallow-Water Flow in the Deepwater Gulf of Mexico," R.M. Ostermeier, J.H. Pelletier, C.D. Winker, J.W. Nicholson, F.H. Rambow, K.M. Cowan, 2000 Offshore Technology Conference, Houston, Texas.

OTC 11973 "Optimizing Deepwater Well Locations to Reduce the Risk of Shallow-Water-Flow Using High-Resolution 2D and 3D Seismic Data," Daniel R. McConnell, 2000

Offshore Technology Conference, Houston, Texas.

OTC 11974 "Shallow Water Flow Prediction From Seismic Analysis of Multicomponent Seismic Data," A.R. Huffman, John P. Castagna, 2000 Offshore Technology Conference, Houston, Texas.

OTC 11976 "New Chemical Systems and Placement Methods to Stabilize and Seal Deepwater Shallow-Water Flow Zones," Larry Eoff, Ron Sweatman, Ronnie Faul, 2000 Offshore Technology Conference, Houston, Texas.

OTC 11977 "Next-Generation Cementing Systems to Control Shallow Water Flow," Ronnie Faul, B.R. Reddy, James Griffith, Rocky Fitzgerald, Bryan Waugh, 2000 Offshore Technology Conference, Houston, Texas.

"Pressure Prediction for Shallow Water Flow Evaluation" Traugott, M.O. and Heppard, P., presented at the 1999 International Forum on Shallow Water Flows, October 6-8, 1999, League City, Texas.

"Rock Physics and Mechanical Considerations for Shallow Water Flow Characterization," Huffman, A.R. and Castagna, J.P., presented at the 1999 International Forum on Shallow Water Flows, October 6–8, 1999, League City, Texas.

"Foamed Cement Job Successful in Deep HTHP Offshore Well," O.G. Benge, J.R. McDermott, J.C. Langlinais, J.E. Griffith, Oil and Gas Journal, March 11, 1996.

OCS Report MMS 2001-015, "Incidents Associated with Oil and Gas Operations, Outer Continental Shelf 1999," U.S. Department of Interior, Minerals Management Service.

"Exposure to Moisture Alters Well Cement," Silk, I., API WG on Bulk Handling & Storage, *Petroleum Engineer International,* pp 45–49, March 1986.

"Hydraulic Wellbore Erosion While Drilling," Chemerinski, B., Robinson, L., World Oil, 1996.

APPENDIX A—SHALLOW WATER FLOW INTERPRETATION GUIDE

Flow risks can be characterized as negligible, low, moderate or high. Consider that it is difficult to judge the severity of a flow. If a flow is observed, the best course of action may be to assume that the flow is severe and to drill ahead with weighted mud. The following is a description of each, based on one set of evaluation criteria.

High—An interval possessing all of the characteristics of a shallow water flow interval, or that ties directly to a shallow flow in an offset well, or is located at a known, regional, shallow flow horizon.

Moderate—An interval meeting the criteria listed above for "High" risk, but which could be breached, or otherwise shows evidence that provides reasonable doubt for the presence of shallow flow conditions.

Low—An interval generally lacking the characteristics of a shallow water flow interval, although some interpretive doubt exists.

Negligible—An interval where data clearly indicate there is no risk of either sand or adequate seal, or where offset drilling has proven the absence of flow risk.

Any one indication can be spurious. Shallow water flow interpretation on seismic data involves accumulation of evidence. The more guide points that can be answered by a "yes" the greater the risk of shallow flow conditions being present.

The evaluation criteria listed below can be used to assess the risk.

a. Does the interval contain an aquifer?

b. Is there a competent regional or sub-regional seal above the potential flow zone?

c. Is there a sand-prone layer contained within a structural trap?

d. Is there a stratigraphic trap formed by dipping sand-prone layer(s) truncated by faulting, erosional downcutting or depositional pinch-out?

e. Is there evidence of high sedimentation rates (>1500 ft/my) and rapid burial leading to pressure disequilibrium?

f. Is there a localized amplitude event consisting of an anomalously bright reflection? If so, can tuning effects be ruled out as the cause?

g. Is there evidence for the presence of a geopressured zone, i.e. stratigraphic layer(s) containing pore pressure greater than hydrostatic pressure?

h. Can a known shallow water flow zone from a nearby well be correlated to the interval? If so, is there consistency of seismic character?

i. Has a nearby well proven that SWF can be ruled out? If so, is there consistency of seismic character? (A negative indicator for SWF risk.)

j. Has seismic sequence analysis identified sedimentary deposits likely to contain a SWF interval?

k. Does the seafloor amplitude map indicate areas of anomalously strong reflection indicating authigenic carbonate hardgrounds associated with seafloor flow?

l. Are mud volcanoes or other expulsion features present on the seafloor?

m. Are buried expulsion features recognized on subsurface data?

n. Does bathymetric mapping indicate the presence of seafloor scarps possibly associated with faults or other pressure conduits?

o. Is there an isolated sand body capable of absorbing excess pressures caused by compaction disequilibrium?

p. Is there evidence of differential compaction resulting in excess pressures transferred from thick overburden areas?

q. Is the zone buried deeply enough (> 500 ft) for development of a sufficiently strong seal?

r. Are there high-amplitude, discontinuous reflectors within expanded stratigraphic sequences?

s. Is the water depth great enough (> 500 ft) to be associated with SWF?

APPENDIX B—DRILLING PRACTICES TO REDUCE RISK OF SHALLOW WATER FLOWS

B.1 General

Drilling practices have a significant impact on formation isolation, development of a sound structural well foundation, and long term well durability. Poor drilling practices or events occurring during drilling can have a significant impact on cementing success.

Communicate information about drilling practices and events related to drilling the interval to be cemented as part of the engineering design for cementing. Service company and operating company engineers should review the following elements of the drilling process as part of cementing operation design.

B.2 Hole Size

Hole size should be picked with several considerations in mind. First, the impact on cuttings removal is critical. Size should be such that cuttings removal can be achieved at annular velocities achievable with the drill-pipe and rig pumps to be used.

Additionally, give consideration to the annular dimensions with casing in the hole and the ability to place cement at the desired rates, considering displacement mechanics. It is too late to discover that effective fluid displacement is impossible once the hole has already been drilled. Drillers should work together with the cementing companies to define the optimum hole size to achieve effective mud removal and annular isolation with the displacement and cementing fluids which are available.

B.3 Use of Pilot Holes

In areas where there has not been prior drilling, it is sometimes desirable to drill a pilot hole to surface casing depth to provide information on possible shallow flow formations. A smaller hole enhances dynamic control. (Standard hole sizes and the shallow depths BML typically do not allow sufficient friction pressure for a dynamic kill.) The size of the pilot hole is dependent on many factors such as water depth, depth to the flowing formation, reservoir characteristics and the wellbore configuration. Typically a 9 $^{7}/_{8}$ in. or 12 $^{1}/_{4}$ in. hole is drilled.

The pilot hole is usually drilled riserless. With the pump rate held constant, the pump pressure or pressure while drilling measurements can help indicate flow. If a significant increase or decrease in pressure is observed, stop drilling and use an ROV to check for flow. If there is flow, mud can be pumped to dynamically kill the well as drilling continues or the well can be displaced with mud heavy enough to prevent flow under static conditions.

B.4 Full Diameter Holes

A full diameter hole can be drilled instead of pilot hole followed by hole opening. The full diameter hole is suitable in most development scenarios, where hole conditions and presence and depth of flow zones are known or with proper engineering where sufficient volumes of weighted mud are available to kill any possible flow. Drilling a full diameter hole has the advantage of minimizing trips and minimizing the amount of time that a hole section is open.

B.5 Hole Cleaning

Hole cleaning is a direct function of annular velocity, cuttings size, mud/sweep viscosity and density.

Understanding the increase in ECD from cuttings in the return fluid and from running pipe has led to changes in operating practices that have reduced formation failure. Lost circulation and shallow water flows have been reduced using a circulation rate of at least 1200 gal/min in a 31 in. hole and 1000 gal/min in a 26 in. hole to achieve desired annular velocities with an appropriate ROP.

Using a sufficient flowrate and controlled ROP will limit the effect of cuttings loading in the annulus. Regular sweeps help remove cuttings, keep the annulus pressure lower and help prevent lost circulation. Weighted viscous sweeps provide additional cuttings lifting capacity. Viscous sweeps should be formulated with significantly higher viscosity than the existing fluid. The sweep volume should be equal to between 100 to 250 linear ft of annulus. Typically, circulation bottoms up or sweeps are run every stand. Foamed sweeps are very effective and recommended prior to spotting fluids in the hole for running and cementing casing.

B.6 Rate of Penetration

Higher ROP reduces open hole time, thus minimizing the exposure of shale to a water-based mud system. This advantage must be balanced, however, against the increase in ECD due to loading of cuttings in the fluid. Consideration should also be given to whether the hole section is to be drilled in one or two passes.

When trying to increase ROP, the most important consideration is maintaining the ability to clean the hole. The drilling fluid must be capable of efficiently carrying the larger volume of cuttings out of the hole. Ineffective hole cleaning can lead to high ECDs, bit balling, high drag, hole pack-off, etc., which can cause lost circulation and other wellbore instability problems.

ROP in the larger, top hole sections frequently needs to be restricted due to hole cleaning constraints. Although flow rates to clean the hole may be achievable, the resulting ECD often exceeds the fracture gradient. In most cases, these hole sections must be "control drilled" to maintain ECD at acceptable level. Methods of optimizing ROP include use of downhole pressure measurement while drilling or hydraulic modeling programs.

To combat these problems, flow rates should be maximized to improve cuttings removal without exceeding the fracture gradient. Mud rheology and flow rate should be optimized to provide the adequate carrying capacity.

B.7 Washout/Hole Enlargement

Hole enlargement can lead to lower annular velocities and difficulty removing wellbore fluids during cementing. These can lead to cuttings loading in the drilling fluid and to failure to achieve annular isolation, respectively.

Most important is to prevent wellbore enlargement due to the mining of sand by preventing or minimizing shallow water flows. Wellbore enlargement in sand formations can also be caused by hydraulic erosion. Hydraulic erosion is caused by excessive bit nozzle velocity and turbulence at the bit. Secondary erosional effects can be limited by controlling the annular velocity to avoid turbulence across the BHA.

Large washouts make it difficult to successfully install and cement a casing string, which can lead to later problems like load shedding, casing buckling and wear. Casing buckling in the washed-out sands may prevent physical reentry into the well. Uncontrolled flows can also lead to compaction and subsidence of the flow zones, impacting the integrity of nearby wells or structures.

These effects may be managed by controlling drilling mud properties, nozzle velocity and annular velocity to minimize turbulence. Additionally, when circulating sweeps, do not leave the bit across sands.

B.8 Lost Circulation

Lost circulation in shallow sediments is commonly due to wellbore pressures exceeding the strength of the formations and "fracturing" them. Factors leading to this excessive pressure are; high friction pressures of fluids from high pump rates, high pressures due to loading of cuttings in the annular fluid and annular fluid densities higher than can be supported by the formations.

These factors should be managed to prevent losses when drilling the shallow hole sections above and through the potential SWF sands.

B.9 Drilling Fluids

The drilling fluid most commonly used in drilling the holes for conductor and surface casing is seawater. The objective of drilling a hole that allows effective placement of cement, thus resulting in annular isolation and support of the casing should be kept in mind. The problem of hole enlargement and potential lost circulation should be accounted for and the drilling fluid designed accordingly. Sometimes this means that a drilling mud must be used. In such cases, since the fluid is circulated to the sea bed and not reused, large volumes of weighted sacrificial drilling mud are required. Handling such large volumes must be accounted for in the logistical and well operations plan.

Drilling fluid should be designed with the following criteria. It should have density that will not violate the pore and fracturing pressure limits. The drilling fluid must be formulated to satisfy the prevailing regulatory environmental discharge regulations. Viscosity is maintained so that cuttings can be efficiently removed, while not generating excessive friction pressure that will raise the ECD to cause fracturing.

B.10 Riser vs. Riserless Operations

Common practice is to drill the conductor and surface casing sections riserless with seawater, taking returns at the seabed. Upon reaching TD of the hole section and before pulling out of the hole, a weighted kill or pad mud is normally spotted on bottom. This aids in keeping the hole open and minimizes the chance of flow if a SWF interval has been penetrated. It is critical to ensure that the well is dead prior to cementing casing.

If a more severe shallow water flow zone is penetrated, it may be advantageous to drill the section riserless with weighted, sacrificial mud rather than seawater. In most cases, however, seawater is used until flow is observed using a pressure while drilling measurements and/or ROV. If a conversion to mud is necessary, large volumes of shore prepared mud (as much as tens of thousands of barrels) will be required. In a development drilling campaign, the Two Riser System has been used to drill certain shallow water flow sections under controlled conditions.

B.11 Equivalent Circulating Density (ECD) Management

Pressure control in the wellbore is critical to successful drilling and cementing in deepwater developments, particularly in SWF intervals. Pressure control is maintained by the hydrostatic pressure of the fluid in the wellbore when the well is static.

Circulation of fluids and drilling operations increase the pressure in the wellbore above the static pressure. Frictional pressure from fluid circulation and cuttings loading in the drilling fluid raise the effective density in the wellbore. This is commonly referred to as the Equivalent Circulating Density (ECD). ECD must be managed within the constraints of pore and fracturing pressures.

B.12 Surge Pressures

Running casing too fast can cause surge pressures which break down the formation and lead to lost circulation.

APPENDIX C—PROCESS FOR SUCCESSFULLY CEMENTING CASING HAVING SHALLOW WATER FLOW POTENTIAL

C.1 General

The following is a description of the process for drilling and cementing a casing string in situations where there is risk of shallow water flow (SWF). A checklist can be prepared from this description. It should include specific parameters and can be used as a guide for implementation of the well plan. For each casing string cemented having SWF potential, this process can be documented and used for post-evaluation to determine future modifications or improvements to effectively control shallow water flows.

C.2 Initial Well Planning

C.2.1 Pick targets of well.

C.2.2 Select best surface location to minimize the risk of SWF and hit targets (see Appendix A—Shallow Water Flow Interpretation Guide).

C.2.3 Set appropriate driven or jetted pipe.

C.3 First Cemented Casing Options

C.3.1 Option A—Drill and set first cemented casing at a depth that provides an adequate casing seat and is set just above the first high potential SWF zone. (Top-set technique). Preferably, the casing should be set in shale or other suitably competent formation in order to achieve a seal at the casing shoe. Use appropriate methods for selection of the location of the shoe; avoid setting the casing shoe in a sand. Displace the hole with mud that does not exhibit progressive gel strength behavior. The density of the mud should be high enough to control the pore pressure, but less than the fracturing pressure. Use drilling practices that minimize the risk of breaking down weak formations, allowing flow or causing an irregular or washed out wellbore. Monitor returns to sea floor and make flow checks to help ensure that flow is not occurring. Consider the use of pressure while drilling measurements to provide an early indication of SWF. If the SWF interval is penetrated, kill the well with mud and fill the rat hole with viscous, weighted mud in preparation for setting casing in a competent formation above the SWF zone. If it is necessary to set casing through the SWF zone, consider that multiple SWF zones may exist and it may be preferred to drill through all known SWF intervals before setting casing. Once the casing point is reached, check for flow (ensure that flow is dead) and cement according to best practices for cementing across a potential SWF zone.

C.3.2 Option B—Drill and set first cemented casing at a depth that provides an adequate casing seat and is set through the potential flowing zone(s). In this case, additional safeguards must be taken to prevent the flow and to control flow if it occurs. Be aware that multiple SWF zones can exist and that for this option, it is preferred to drill all of them before running casing. However, depending on the number of potential SWF zones, the distance between them, and the hole size, this may not be practical. Follow the criteria for cementing through SWF zones discussed below.

Note: The decision to top-set the first cemented casing or to set the first cemented casing through the SWF zone is based on a number of factors including: severity of SWF potential, mud storage capacity of the drilling rig, proximity to shore-based supply locations, offset well experience, operator experience, etc. Setting the first casing string through the SWF zone can save a casing string, but exposes the well to additional risks compared to drilling through the SWF interval with a drilling riser in place. The hazard assessment for the two techniques will vary by operator, location, and well type (exploratory or developmental). However, in either scenario, the necessity for placing a flow-mitigating cement system across the SWF interval remains the same.

C.4 WOC – Waiting-On-Cement—until required compressive strength is achieved based on laboratory tests under conditions simulating those found in the well.

C.5 Formation/Shoe analysis—Perform a thorough pore pressure/fracture gradient analysis or LOT/FIT to determine if the shoe will be capable of withstanding the pressure of fluids required to contain potential SWF in next hole section. If LOT or FIT is not adequate, perform sealing/consolidating treatment to improve formation strength or drill ahead, constrained by the properties of the formation. If option to drill ahead is used, give consideration to setting a contingency string in a competent formation, allowing desired LOT/FIT. This string can be a conventional casing, liner or an expandable liner.

C.6 Drill through the potential SWF zone—When flow is encountered, evaluate its severity as minor, moderate or severe using the following guidelines:

a. Minor—Drill ahead with ECD and ROP management using seawater and prehydrated fluid sweeps.

b. Moderate—Kill the flow and evaluate the well. Drill ahead with ECD and ROP management using drilling mud suitable for riserless drilling.

c. Severe—Kill the flow and evaluate the well. Switch to weighted drilling mud suitable for riserless drilling and drill ahead with ECD and ROP management.

Keep in mind it is difficult to judge the severity of a flow. If flow is observed, the best course of action may be to assume that the flow is severe and to drill ahead with weighted mud . Take the action as indicated based on the flow severity. In all cases, avoid extended uncontrolled flow periods.

C.7 Use drilling practices which minimize the risk of breaking down weak formations, allowing flow or causing irregular or washed out hole. Monitor returns to the sea floor, make flow checks to determine if the SWF zone is flowing. Consider use of pressure while drilling measurements to control drilling rate and watch for indications of SWF. When flow occurs, mud up and drill through all of anticipated flow zones as quickly as prudent. Once all the zones are penetrated, if the zone is flowing, kill the flow with appropriately designed kill fluid. Keep in mind the kill mud has to be displaced in the cementing process to ensure that good isolation is achieved. The kill fluid should be designed with low fluid loss, low yield point and gel strength profile that is relatively flat and less than 25 lbf/100 ft^2 when measured at BHT. Consider use of a settable formulation for the kill fluid, especially if there is a chance that the wellbore fluid cannot be effectively displaced during cementing. Otherwise, the weak formations may be fractured and an underground, uncontrolled flow may occur, making it much more difficult to remediate.

C.8 Rat hole considerations—If rat hole has been drilled and will not be cemented, fill the rat hole with viscous, weighted mud, preferably more dense than the cement to avoid fluid swapping as the well is being cemented or after cement placement.

C.9 Run casing through the SWF zone—Consider using an upjet shoe to enhance complete coverage of cement around the shoe and minimize washing the hole out around the shoe. Apply centralizers according to the requirements of the design for effective mud removal. Use the inner string cementing technique. Space out the inner string to leave the end 50 – 80 ft above the casing shoe. Avoid running speeds which would break down weak formations, causing lost circulation. When on bottom, fill the annulus between the inner string and casing with fluid to be used as displacement fluid and set the seals.

C.10 Cement Casing Through the SWF Zone

C.10.1 CEMENTING DESIGN

C.10.1.1 Mud removal design—Design the mud removal process using engineered flow regimes, casing standoff (centralization) and cementing preflushes, spacers and cement slurries that are capable of removing the fluid in the hole at the time of cementing. Give consideration to pipe and hole size (actual, not bit), hole deviation, and wellbore fluid properties. Additionally, design flow regimes and rates with the knowledge of potentially weak formations so that ECD does not exceed these limits. Centralizers should be selected based on their properties (restoring force, running force, design hole size, minimum and maximum OD) that are consistent with the well being cemented.

C.10.1.2 Preflush (if applicable)—Design the preflush(es) with consideration for base fluid properties (its ability to remove the fluid ahead and leave the formation and pipe surfaces water-wet). Other considerations include: density (and hydrostatic pressure), volume, annular fill, surfactant (if required) and concentration, optimum flow regime, rheological properties at BHCT, allowable rates for the optimum flow regime.

C.10.1.3 Spacer—Design spacer(s) with consideration for base fluid properties (its ability to remove the fluid ahead and leave the formation and pipe surfaces water-wet). Other considerations include: density (and hydrostatic pressure), volume, annular fill, surfactant (if required) and concentration, optimum flow regime, rheological properties at BHCT, allowable rates for the optimum flow regime.

C.10.1.4 Lead cement (if applicable)—Design the lead cement(s) with the following considerations: required top, excess fill factor, volume, density (and hydrostatic pressure), minimum strength (or modulus) at key times and points in the well (including mud line), fluid loss, free water, rheological properties, thickening time under well conditions, gas/fluid flow control mechanism (if applicable), optimum flow regime, allowable rates for flow regime. If foamed, include appropriate design of base cement in conjunction with required gas volume (in place in annulus) to achieve required durability/permeability/strength requirements.

C.10.1.5 Tail cement—Design the tail cement with the following considerations: required top, excess fill factor, volume, density (and hydrostatic pressure), minimum strength (or modulus) at key times and points is the well, fluid loss, free water, rheological properties, thickening time under well conditions, gas/fluid flow control mechanism (if applicable), optimum flow regime, allowable rates for flow regime. Strengths should be measured at conditions found at critical points in the wellbore, including at the shoe and at the potential flowing formations. If foamed, include appropriate design of base cement in conjunction with required gas volume (in place in annulus) to achieve required durability, permeability, and strength requirements.

C.10.1.6 Cementing fluid testing—Construct test temperature schedules using measurements from offset well data, measurements in the current well and simulators to evaluate heating and cooling conditions as the fluids are pumped into the well. In addition to standard testing of cement slurries, test the spacer/preflush fluids. These tests include compatibilities with the mud and cement and surfactant optimization tests when surfactants are used. Verification tests should be performed on samples of blended cement taken at the bulk plant or at the rig.

C.10.2 CEMENTING EXECUTION

C.10.2.1 Land casing and condition hole—Once casing is landed, circulate appropriate fluids to condition the hole prior to cementing. Fluid design should consider control of potentially flowing formations and ease of removal by the mud removal/cementing process. While observing for unusual events using the ROV, circulate at least one bottoms up to check the floats, check for other operational problems and condition the hole. This will require large volumes of kill mud. If possible, move pipe according to the plan while conditioning.

C.10.2.2 Mix and displace preflushes and spacers—Mix the spacers and preflushes according to the design. Pump them into the well and displace at the rate required for mud removal as designed using the displacement simulator. Consider moving pipe while pumping the preflush and spacer.

C.10.2.3 Mix and pump the lead cement—Mix the lead cement according to the design (density, volume, gas ratio if foamed). Pump at the rate required by the design. Note that the rate at which the lead slurry is being pumped affects the rate at which the preflushes and spacers are being circulated in the well. Also, "u-tubing" can cause the actual rate in the annulus to be greater than the pump rate. Care should be taken to follow the pumping schedule supplied by the design engineer to ensure the proper rates for mud removal in the annulus. Observe returns of fluids using the ROV.

Note: The downhole rate and rate of returns for a foamed cement slurry can be greater than the rate at which unfoamed base slurry or displacement fluid is being pumped.)

C.10.2.4 Mix and pump the tail cement—When returns of lead slurry have been confirmed by the ROV or the planned volume has been pumped, mix the tail cement according to the design (density, volume, gas ratio if foamed). If slurry is being foamed, stop the gas to leave unfoamed cement in the shoe and annulus across the shoe joint. Pump at the rate required by the design. Note that the rate at which the tail slurry is being pumped affects the rate at which the lead slurry is being circulated in the well. Also, "u-tubing" can cause the actual rate in the annulus to be greater than the pump rate. Care should be taken to follow the pumping schedule supplied by the design engineer to ensure the proper rates in the annulus. Too great a rate can result in high ECD leading to lost circulation. If observation by ROV indicates lost circulation, slow rate to aid in healing the loss.

C.10.2.5 Displace the cement—Displace the cement using the desired displacement fluid. Note that returns may slow when switching from cement to displacement fluid, as the "void" created by u-tubing has to be filled. The degree to which this occurs depends on the hydrostatic balance in the pipe vs. the annulus (including sea water column). Stop displacing to leave 40 ft – 50 ft of cement inside the casing. Check that the floats are holding. If the floats are holding, continue with "out of hole" operations preparing to drill the next hole section while WOC.

C.10.2.6 Setting wellhead seals—Preferably, the wellhead seals should not be set until the cement across the potential SWF zone has reached "initial set." This will maintain hydrostatic pressure on the cement as it sets.

C.10.2.7 Clean out riser—When riser has been installed, perform operations to clean out the riser.

C.10.3 WOC—Wait on cement until the tail cement has had sufficient time to develop 500 psi and the lead cement has time to develop 100 psi across the potential shallow water flow zone. If it is the foundation (first) casing, allow time for 250 psi by the lead cement at the mud line. Consideration may be given to making strength measurements on-site for determination of WOC time. This requires careful control of temperatures to simulate placement conditions. The only practical method of testing on-site is the use of an ultrasonic cement analyzer. Since this device uses a correlation to compute compressive strength, care must be taken that proper correlations are available and used. Temperature logs may be run to detect the tops of cement and indicate setting of the cement. All tests must be conducted with temperature and pressure schedules tailored to those found in the well during cementing.

C.10.4 Monitor well for indications of flow—After the cement is in place, monitor the wellhead area for indication of flow. If practical, the wellhead should be monitored for 24 hours after cementing. If flow is observed, evaluate conditions for further actions.

C.10.5 Actions following flow after cementing—If flow is observed, further actions are dependent on numerous factors. These factors could include things such as the nature of the flow, timing of flow initiation, wellbore configuration, proximity of the well to other subsea assets, and well objectives. The possible actions to consider might include, in addition to others: 1) closing shut in devices if they are available and have not been previously closed; 2) if the flow occurs immediately after the cement job, then replacement of the cement with kill weight mud may be possible; 3) further observation of the flow to determine if the flow may cease; 4) if the flow is minor and does not carry a significant quantity of sediment, then it may be possible to continue with the well, depending on well objectives, while continuing to monitor the flow; 5) if the well is deemed too unstable to accomplish the well objectives, move a sufficient distance and spud a new well; 6) determine the location of the flow and perforate and squeeze accordingly; or other action based on the conditions and objectives at the time.

C.10.6 Hang the casing and set the seals.

C.10.7 Repeat the process for the next hole section—After waiting adequate WOC time, and no flows have been observed, or after flows have been repaired, drill out shoe and repeat the appropriate steps to drill the next hole section.

APPENDIX D—FOAMED CEMENT INFORMATION

D.1 Introduction

Foamed cement is produced by dispersing nitrogen or air directly into a cement slurry which contains foaming agents and stabilizer. This results in a cellular or foamed cement. The density of the foamed cement is determined by the density of the base slurry, the amount of gas injected into the slurry and the downhole temperature and pressure.

Studies of compressive and tensile strengths of foamed cement have shown that the strength development is very comparable and even exceeds most conventional cements of comparable density. Tests conducted on foamed cements of 9.5 lb/gal and 7.9 lb/gal indicated a shear bond to compressive strength ratio of 13% and 17%, respectively. Therefore, it would appear that a foamed cement would be capable of supporting a greater load due to shear, than would a non-foamed cement of the same compressive strength.

The thermal conductivity of foamed cements has been reported in the range of 0.25 W/m°C – 0.7 W/m°C (0.15 – 0.4 BTU ft/ft^2 hour °F) compared to a 1.1 W/m°C (0.64 BTU ft/ft^2 hour °F) for normal density cement. This low conductivity makes foamed cement desirable in situations where insulating properties are advantageous. Where insulating properties are desired, thermal conductivity data should be developed for slurries under the conditions of placement, including temperature and pressure.

D.2 Foamed Cement Design Methods

There are two basic methods of designing a foamed cement job: the constant gas method and the constant density method.

The constant gas method is operationally the simplest approach. The gas (nitrogen) is injected into the slurry at a constant ratio (scf/bbl). This produces a cement column of varying density with the density higher at the bottom of the column. This method has two advantages. First, the mixing procedure is relatively simple in that once a constant mixing rate and nitrogen injection rate has been established only minor adjustments should be necessary. Second, the denser cement at the lower section of the column will have higher strengths and lower permeability. This can minimize waiting on cement time to drill out. However, there is a disadvantage to this method if a long column of foamed cement is required. Due to variation in compression from hydrostatic pressure, the density of the foamed cement at the top of the column may be so low that the slurry will become unstable. The gas phase may break out of the slurry or the permeability of the foamed cement could be higher than desired. This is normally not a problem in deep water wells since there is adequate pressure imposed by the column of sea water above to maintain optimum conditions for a well-designed and properly mixed foamed cement.

The second method of designing the foamed cement job is the constant density method. This requires adjusting the gas/cement ratio throughout mixing so that when the foamed cement is in place, the density is uniform throughout the entire cement column. This operation is more complex since the gas rate must be continually increased throughout the mixing operation. The use of automated control systems makes this method as viable as the constant gas method. In many cases a combination of the two methods will produce the best results. The interval to be cemented is divided into sections and the gas/cement ratio adjusted for each section rather than continuously throughout mixing. This results in a foamed cement column that has a varying density for each short section but the overall variance in density would not be as great as if the job was designed as one long section. Thus the cement properties such as permeability and strength will also have less variance throughout the entire column.

A model of either of these two methods or a combination of the two can be generated with the aid of a computer program to determine the simplest and most effective cement design which meets the requirements for density in the well. Whichever method is chosen, the following guidelines should be followed:

a. The density should be controlled so that the hydrostatic pressure does not exceed the fracture pressure of the formation.
b. Foam densities less than 8.33 lb/gal or more than 4 lb/gal lighter than the base slurry density should be avoided if low permeability is desired unless permeability data shows the slurry to be acceptable.
c. A foam generator or static inline mixer is necessary to ensure proper bubble size and the bubbles are dispersed evenly throughout the cement slurry.

D.3 Keys to Successful Foamed Cementing

Following are keys that should be incorporated into the cementing program when foamed cement is to be used.

1. Communication.
   a. Foam design.
      i. Base cement slurry.
      ii. Constant rate versus constant density considerations.
   b. Logistical considerations of rig/location.
   c. Between service company and operator—rig operations and engineering.
   d. Between pump operator and nitrogen unit operator during pumping operations.

2. Maintaining constant rate and proper density of base (unfoamed) slurry.
3. Maintaining correct ratio of nitrogen to base slurry.
4. Planning contingencies for possible problems during job
   a. Back-up communications.
   b. Loss of automation on automated units.
   c. Poor cement supply (dry and slurry), density variation.
   d. Loss of key equipment—cement pumper, liquid additive system, nitrogen unit.
   e. Line failure/leaks/plugs.

5. Safety.
   a. Location (placement) of energized fluid equipment
   b. Securing energized fluid lines.
   c. Protecting steel deck members from cryogenic fluids, in case of liquid nitrogen leak.
   d. Restricting access to areas of pressurized equipment during job.

6. Quality Control.
   a. Isolation of cement and additives.
      i. Pilot testing for slurry design.
      ii. Pre-job field blend testing with rig samples.
   b. Calibration of liquid additive system, flow meters, pressure gauges, density meters.
   c. Equipment maintenance – cementing and nitrogen units, foam generator assembly, 1-in. and 2-in. valves.
   d. Data collection during job.
      i. Pump rates.
      ii. Pressures.
      iii. Nitrogen flow rates.
      iv. Cross-checks of liquid additive usage (gauging tanks to check liquid additive system).
      v. Cement density—unfoamed and foamed.
      vi. Cement returns from annulus.

D.4 Checklist for Foamed Cementing Operations

1. Formulate base cement slurry for cementing operation with lab/district materials or cement isolated for the job.
   a. Thickening time.
   b. Compressive strength—unfoamed and foamed slurries.
   c. Rheological properties.
   d. Critical Gel Strength Period—unfoamed slurries.
   e. Solids suspension.
   f. Free water.
   g. Foam stability (Foam half-height/liquid drainage rate).

2. Pilot test base cement slurries with materials to be loaded for cementing operation.
   a. Isolate cement.
   b. Isolate additives and record lot numbers.
   c. Record ID numbers of tanks loaded with liquid additives (TOTE tanks, etc.).

3. Determine required nitrogen rate for base slurry to obtain desired downhole foam density.
   a. Determine if constant gas injection rate method can be used.
      i. Calculate foam density at top and bottom of column.
      ii. Calculate average foam density in column and check against fracturing/pore pressures.
      iii. Adjust nitrogen rate, if required, and re-check foam density against fracturing/pore pressure.
      iv. Determine if desired performance properties meet the requirements.
   b. If constant gas ratio cannot be used due to foamed column length and fracturing/pore pressure limitations or performance properties, divide the job into stages of constant gas injection.
   c. Use the minimum number of stages possible.

4. Determine minimum and maximum gas rate for nitrogen pumping unit.
   a. Determine the maximum cement slurry rate possible based on nitrogen requirements for foam density and nitrogen pump(s) rate limit.
   b. Determine the minimum cement slurry rate based on nitrogen requirements for foam density and nitrogen pump minimum rate limit.
   c. Notify all personnel of these cement rate limits and target cement pump rate for job at 80% – 90% of this rate (maximum).
   d. Determine maximum and minimum rates of liquid foamer unit.
   e. Liquid pump rate may be the limiting factor, depending upon cementing unit capability, nitrogen unit capability, and nitrogen requirements. Note if the rate limit of the cementing unit is the rate limiting equipment.
   f. The objective is to operate the nitrogen pumper and cement pumper in the middle to upper end of their power curves.

5. Consult with rig foreman and toolpusher to locate nitrogen pumper, nitrogen tanks, placement of nitrogen injection lines and foam generator.
   a. Nitrogen unit operator, cement pump operator and supervisor should have visual or radio contact with each other.
   b. Place nitrogen equipment out of main traffic areas, if possible.
   c. Run nitrogen lines out of high traffic areas and where the line can be secured at regular intervals to

fixed rig equipment (to prevent lines whipping around if they part).

d. Foam generator assembly should lie flat on the deck or be mounted in a secured manifold.

e. Develop contingency plan for bleed-off of pressurized lines if a valve plugs or cannot be opened. (May require extra 1-in. and 2-in. valves.)

f. Water and a water hose should be available near all nitrogen equipment and water should be run on the deck or in a pan to protect steel from cryogenic temperatures (– 373°F) in case of liquid nitrogen leak.

g. Use plastic barrier tape to mark off 'restricted' or low traffic areas during the cement job.

6. Arrange for radios and headsets for primary communications during the cementing operation for everyone having an active role in the job.

7. Arrange for alternative methods of communication in case radios are not available or fail(backup radios or blackboards and chalk, etc. like used at car races).

8. Determine method for providing constant density, supply and pump rate of base cement slurry.

a. Process density control.

b. Batch mixing if cement volume is small.

c. Averaging or holding tank for continuous mixing operations.

9. Arrange for job monitoring/data acquisition equipment.

a. Check calibration of all sensors.

b. Check cables, connectors and output devices.

10. Arrange for tank straps/gauges to monitor liquid additive usage during the job and verify correct metering by automated liquid additive system.

a. Prepare table with cumulative cement volume (base cement slurry) and cumulative amounts of liquid additives that should be consumed during the job.

b. Gauge or strap all liquid additive tanks at regular intervals during the job and compare usage with table values.

11. Prepare table of nitrogen rate (scf/min) for range of base cement slurry pump rates.

a. Basic requirement for non-automated nitrogen/cementing unit equipment.

b. Back-up in case automation units on equipment don't perform properly.

c. Increment unfoamed cement slurry rates on 0.1 bbl/min within the minimum and maximum pump rates determined in Item 4 above.

12. Calibrate all equipment on location prior to the job.

a. Flow meters.

b. Liquid additive pumps.

c. Density meters.

d. Pressure gauges/transducers.

e. Data acquisition devices.

13. For automated equipment, have an electronics technician trained for that equipment on location for the job.

14. Take samples of cement.

a. As loaded on the boat.

b. When transferred from boat to rig.

c. During job (wet samples at least at beginning and end of each slurry pumped).

15. Check load tickets.

a. Verify amounts.

b. Verify lot numbers for isolated additives.

c. Verify tank numbers for bulk liquid additives (TOTE tank serial numbers).

16. Inform rig personnel of dangers of pumping energized fluids and direct them to avoid the rig floor and nitrogen equipment areas during the job. Restrict traffic in these areas.

APPENDIX E—PRE-JOB PREPARATIONS

Successful cementing depends on a number of practices that are conducted prior to any cementing job. These include bulk blending, sampling and testing methods, materials inventory, equipment maintenance and calibration and standards of rigging up to perform the job.

E.1 Bulk Blending, Sampling and Testing

Industry-recognized best practices for bulk blending and sampling of blended cements should be used for cement blends. Some of these practices are described in an article summarizing the recommendations of the API Work Group on Bulk Cement Handling and Storage of the Eastern Hemisphere Task Group. These best practices include:

a. Recommended maximum fill for weigh batch blender.

b. Weights of all sack (non-bulk) and partial sacks of materials used for each batch.

c. Weigh batch load print out for each batch of cement.

d. Number of transfers between tanks (and % fill of tanks) to improve uniformity of blending.

e. Lot numbers of all additives used for each batch.

f. Date and time loading was performed.

g. Bulk Plant Operator who performed loading.

h. Sampling methods and amount of sample to obtain for each load/batch.

i. Pneumatic equipment requirements, including maximum humidity in air supply.

Samples should be taken at the following locations:

a. Bulk plant when cement is loaded.

b. During transfer to rig.

c. During cementing operation.

It is advisable to verify performance by laboratory tests on samples from the blend. Note, however, that care must be taken to ensure that samples taken and tested are representative of the blend. Certain sampling and material handling procedures must be followed to ensure that the samples are representative.

Long-term storage of cements may have adverse effects on the cement's performance. The type and degree of the effects may vary depending on the composition of the slurry. In some cases, free fluids have been found to be higher after storage. Thickening times and viscosity may also be altered by long storage. Early compressive strength development may be slightly delayed but final compressive strengths remain essentially unchanged.

After extended storage, the cement should be checked to verify its performance.

High-performance cement blends formulated with calcium sulfate hemi-hydrate or high-aluminate cements should not be stored for long periods without good humidity control. Laboratory studies indicate these cements can be affected more by long storage periods than other high performance cement types.

E.2 Materials Inventory

An accurate inventory of all materials to be used for the cementing operation should be prepared. Reconciliation of materials/mass-balance checks should be performed immediately following the job as part of quality assurance for the cementing operation. Lot numbers for all materials should be recorded as part of this inventory.

E.3 Equipment Maintenance Checks

All equipment should be checked for proper operation. Checks should be performed from the perspective of the upcoming job requirements. Maintenance records should be reviewed for recurring problems. Verification of equipment checks should be reported to service company and operating company engineering and operations staff prior to start of the cementing operation.

E.4 Equipment Calibration

All sensors, meters, and metering equipment should be checked for proper operation immediately prior to the cementing operation. This includes flow meters, pressure gauges and transducers, liquid additive pumps, density/mass flow meters, etc. Calibration records and calibration frequency should be checked. Records should be reviewed for recurring problems or out-of-specification performance. Verification of equipment checks should be reported to service company and operating company engineering and operations staff prior to start of the cementing operation.

E.5 Rig-Up

Equipment must be rigged up according to prudent operational and safety procedures. Consideration should be given to:

a. Communications between all parties involved in the operation.

b. Safety of personnel and equipment involved in the operation and those working nearby.

c. Ability to perform the operation according to the prescribed procedures.

d. Contingency plans.

When energized fluids are to be used during the cementing operation, additional considerations should be given to:

a. Check valves appropriately placed.

b. Foam generator.

c. Bypasses.

d. Containment for liquid nitrogen spills to protect facilities from cryogenic damage.

e. Circulation of energized fluids into the riser and to surface when a riser is installed.

APPENDIX F—CEMENTING MATRIX

18.0.0.1 A data sheet (Key Cementing Parameters for Shallow Water Flow Hazards in Deep Water) is provided to assist in assessing the cementing process. The drilling team can use the spreadsheet to evaluate the plan prior to the implementation of the cementation. After the cement job, it can be used as a post-evaluation tool. When coupled with an assessment of flow control and other zonal isolation assessment, the cementing matrix can be used for continuous process improvement.

Table A-1—Instructions for Completion of Key Cementing Parameters for Shallow Water Flow Hazards in Deep Water

This matrix is to be used to evaluate the potential impact of elements of the cementing process on its success. The sheet should be completed by the operator during the planning of the well to highlight areas needing improvement. At the conclusion of each string on which it is used, the scores for each parameter should be evaluated again and used as a post job evaluation. The sheet can be printed at each of these stages and placed in the well file. The scores, both by major category and the total can be compiled in a database and, with evaluation of flow, used for process improvement.

Explanation of Terms	
Max Points	The maximum number of points to be assigned for the parameter if the recommended criteria are met completely.
Plan Score	The score for the parameter based on the degree to which the parameter is met in the design of the well.
Performance Score	The score for the parameter based on the degree to which the parameter was met when the operation was performed on the well.
Actual Value	The actual value (not score) of the parameter when the operation was performed. For instance, if the fluid loss of the pad mud is 12, enter 12 for the Actual Value while the Performance Score is 2.
Use of Matrix to Assess Areas for Improvement	
Individual parameter Totals	Each of the critical parameter categories can be evaluated by comparing the Total Score against the possible score (Max Points) for that category. If the earned score is less than half the possible score, consideration could be given to adjusting parameters to increase the score.
Sheet Total	If the earned sheet total is low, consideration could be given to increasing the score by improving individual parameters. The greater the risk and severity of shallow water flow, the more important to increase the score.
Parameter	**Directions**
Site Selection	Assign 10 points if the criteria listed in Appendix A or an equivalent process were used to evaluate and select the drilling site based on potential for shallow hazards. No points are assigned if not.
Gel Strengths @ BHT	Assign points if criteria are met. For greater gel strengths, assign less points, according to value.
Density	Assign 4 points if criterion is met or 0 if it is not.
Fluid Loss	Assign 2 points if criterion is met.
Hole Diameter	Assign points if criterion is met, or scale points if it is not.
Clearances	Scale points based on degree to which criterion is met.
Rathole	Assign full value if density is greater than that for the cement to be used.
Flows	If flow occurs, assign full value if action to control is initiated as soon as it is encountered. Reduce points if flow continues for long period.
End of inner string	Points are given if criterion is met.
Lost Circulation	Assign all points if full returns were observed and if computer simulations indicated that fracturing pressure is not exceeded during conditioning and cementing.
Static Time	To minimize gel strength development during static time, pressure test lines before beginning conditioning. Assign all points if the static time is < 5 minutes total from start of conditioning until end of cementing. No points are earned if the time is > 15 minutes.
Mixing and Placement Rate	Full points are assigned if the rate at which fluids are circulated during cementing (when fluids are being displaced in the annulus) is designed to meet specific engineered mud removal criteria using computer simulations. Otherwise, no points are earned.
Centralization	All points are earned if centralization is optimized with mud removal criteria through the SWF zone. Otherwise, none are earned.
Spacer	Assign all points if the spacer is designed so that density never allows the wellbore pressure to fall below pore pressure and volume is sufficient for 500 feet of fillup in the annulus. Scale points if less than 500 feet of fillup with none given for less than 100 feet.

Instructions for Completion of Key Cementing Parameters for Shallow Water Flow Hazards in Deep Water (cont.)

Parameter	Directions
Fluid compatibility tests	All points are earned if compatibility of spacer with mud and cement has been tested and found to be compatible. Otherwise none are earned.
Circulation Volume	Scale points based on volume circulated before cementing. Give 0 if only drill pipe volume is pumped.
Well Control	Assign all points if the well is in overbalance condition at all times during the conditioning and cementing based on computer simulation and no flow occurs. If underbalance or flow occurs, assign no points.
Pipe Movement	All points are earned if pipe is moved during conditioning and/or cementing. Otherwise, none are earned.
Temperature for Cement Testing	All points are earned if temperature schedules have been established based on measurements combined with computer modeling and/or offset well data. No points are earned otherwise.
Slurry Design (compressible slurry)	All points are given if the slurry is a foamed cement slurry. If gas-generating slurries are used, assign 3 points. None are given otherwise.
Slurry Design (gel strength)	All points are given if the Critical Gel Strength Period is less than 45 minutes. The value assigned is scaled otherwise. This Critical Gel Strength Period is defined as the time required for the cement to progress from the Critical Static Gel Strength to a static gel strength of 500 lb/100 ft^2. The Critical Static Gel Strength is the gel strength of the cement that results in hydrostatic decay producing an exactly balanced condition in the well. The Critical Static Gel Strength (CSGS) can be computed by: CSGS = (OBP)(300)/(D_{eff}/L), where OBP = Hydrostatic Overbalance pressure (psi) 300 = conversion factor (lb/in.) L = Length of the cement column (ft) $D_{eff} = D_c - D_{OH}$ (in.)
Slurry Design (fluid loss)	All points are assigned if slurry has controlled fluid loss below 100 mL/30 min. Otherwise, points are scaled with no points given if the fluid loss is greater than 500 mL/30 min.
Slurry Design (WOC criteria)	All points are given if WOC criteria (based on critical gel strenth period or compressive strength development) are established and used for various phases of operations up to pressure testing and drilling out the shoe. None are given otherwise.
Slurry Design (density)	All points are earned if density meets requirements for maintaining wellbore pressure between pore and fracturing conditions.
Slurry Design (stability)	All points are given if free fluid, sedimentation and foam stability meet criteria.
Blend verification	All points are earned if tests of cement according to vendor's or operator's quality plan verify critical performance properties of the cement.
Cement Top	All points are earned if cement tops cover critical parts of wellbore, including SWF zone with high performance cement and returns of lead slurry to sea floor.
Rheological Relationships	All points are earned if cementing fluids have rheologies appropriate for effective displacement mechanics.
Cement Mixing Equipment	Points are earned if mixing is by fully functional density controlled mixer or all slurry is mixed to density in batch mixers.
Nitrogen Injecion (foamed cement)	All points are earned if nitrogen injection is using automated process controlled equipment.
Foamer and nitrogen at proper ratio	Points are earned if all foamer and nitrogen are mixed within 10% of design.
Bulk cement delivery	Points are earned if there are no mixing constraints due to interruptions of delivery by bulk cement.
Density Control	All points are earned if cement slurry is mixed within +/- 0.2 lb/gal throughout.

Table A-2—Key Cementing Parameters for Shallow Water Flow Hazards in Deep Water

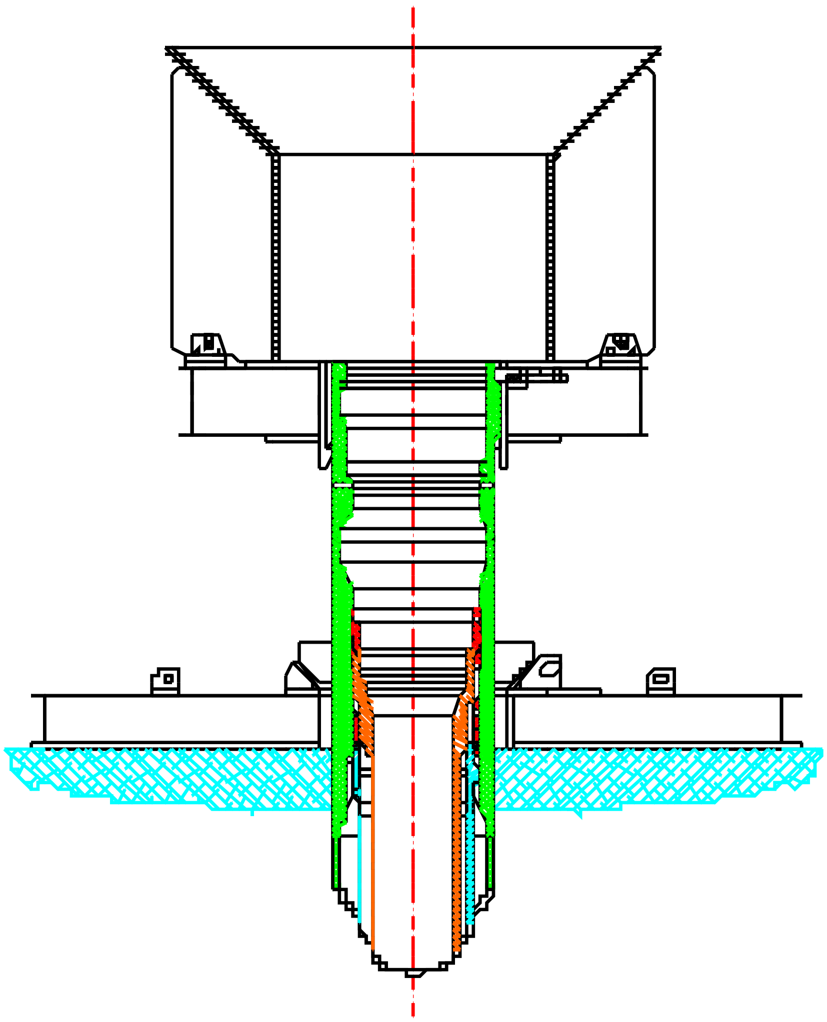
Parameter	Recommended Criteria	Max Points	Plan Score	Performance Score	Actual Value
Site Selection					
Site Selection	Site is analyzed to minimize potential for flow by Appendix A or equivalent process	10			
	Total	10			
Critical Fluid Parameters					
Gel Strengths of Pad Mud @ BHT	10 second, 10 minute and 30 minute gels all < 25 lb/100 ft^2	4			
Density	Sufficient to control flow	4			
Fluid Loss	Pad Mud <15 API	2			
	Total	10			
Critical Well Parameters					
Hole Diameter	Hole diameter is a miminum of 3.0 inches greater than the casing outer diameter	2			
Clearances	Wellhead/cased hole inner diameters are a minimum of 1 inch greater than casing/casing connector outer diameter at all points in the wellbore	2			
Rathole	Rathole is filled with mud with density greater than cement	2			
Flows	Action is taken to kill flow as soon as encountered	8			
End of inner string	Within 80 feet of shoe	2			
	Total	16			
Critical Operational Parameters					
Lost Circulation	Full returns are maintained and fracturing initiation pressure is not violated at any time while running pipe or during conditioning and cementing	3			
Static Time	Pressure test lines before conditioning and < 5 minutes of non-circulation time from start of mud circulation until completion of cementing operation	2			
	Total	5			
Critical Displacement Efficiency Parameters					
Mixing and Placement Rate	Circulation rate in annulus before and during cementing meets mud removal criteria established by computer simulation	3			
Centralization	Optimized for mud removal through SWF zone	3			
Spacer	Optimized density and volume for 500 feet annular fill	2			
Fluid compatibility tests	Compatible	2			
Mud Conditioning Volume	> 1 Annular Volume	3			
Well control	There is no flow before or during conditioning and cementing	5			
Pipe Movement	Pipe is moved to enhance mud displacement	2			
	Total	20			
Critical Cementing Fluids Parameters					
Temperature for Cement Testing	Temperatures established by measurement and/or thermal modelling software	5			
Slurry Design	Compressible slurries are used	5			
	Gel strength development meets maximum time requirements	4			
	Reduced fluid loss slurries are used	2			
	WOC criteria established and followed	4			
	Cement density appropriate for well conditions	3			
	Slurry stability (Free fluid, sedimenation and foam stability meet criteria)	3			
Blend verification	According to quality plan (vendor's or operator's)	3			
Cement Top	Returns of cement are observed at mud line and calculated top of high performance cement is above SWF zone	3			

continued on next page

Key Cementing Parameters for Shallow Water Flow Hazards in Deep Water (cont.)

Parameter	Recommended Criteria	Max Points	Plan Score	Performance Score	Actual Value
Rheological Relationships	Friction pressure of each laminar flow fluid is greater than the fluid it is displacing in all parts of the hole	3			
	Total	35			
Critical Cementing Equipment					
Cement Mixing Equipment	Computer assisted density controlled mixer or batch mixer	2			
Nitrogen Injection (foamed cement)	Automated, process controlled injection equipment	3			
Foamer and nitrogen at proper ratio	Within 10% of design	4			
Bulk cement delivery	No mixing constraints or interruptions due to bulk delivery problems	3			
Density Control	+/- 0.2 lb/gal	4			
	Total	16			
	SHEET TOTAL	112			

APPENDIX G—MECHANICAL ISOLATION



"SHALOW WATER FLOW WELLHEAD SYSTEM"
36" X 26" X 20"

Figure G-1 — Example of Typical Wellhead With Mechanical Isolation

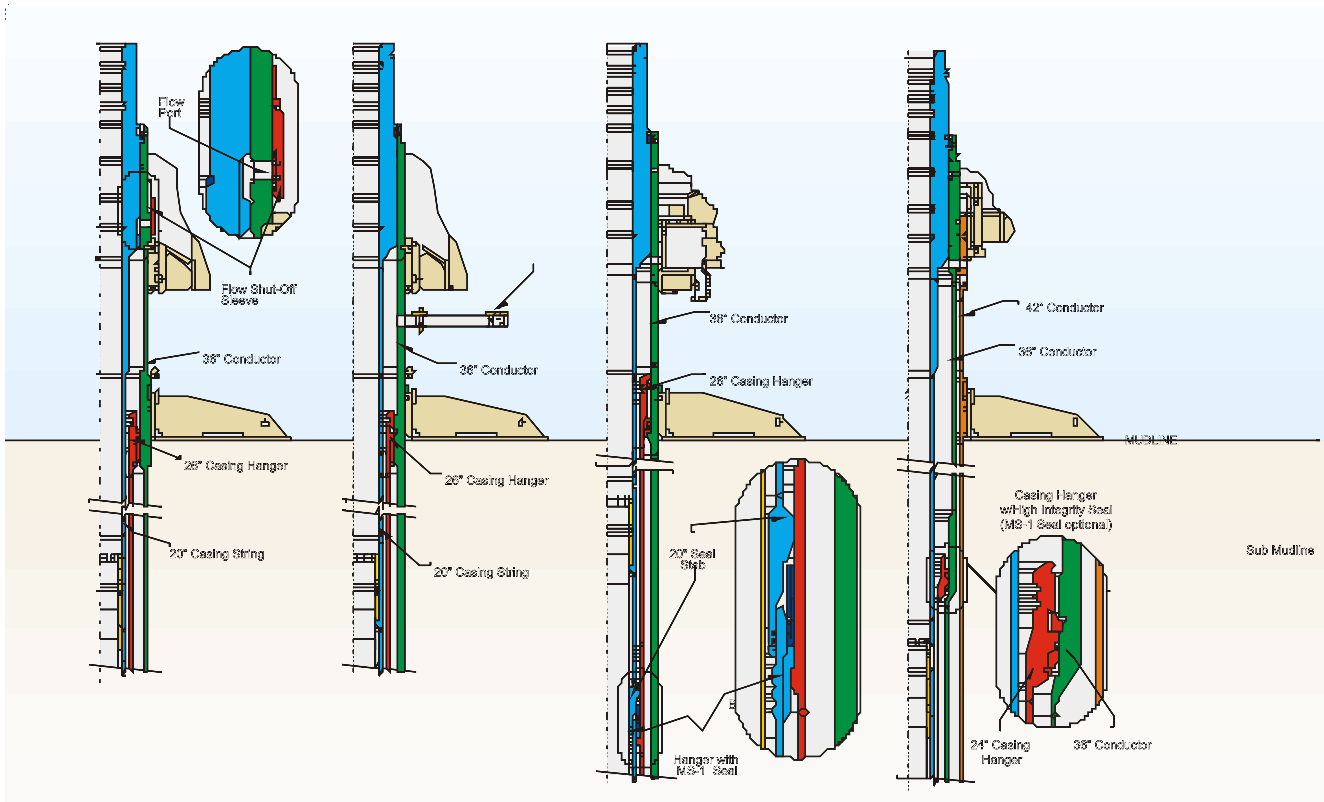


Figure G-2 — Example of Typical Wellhead Configurations With Mechanical Isolation

2002 Publications Order Form

API

American Petroleum Institute

Available through Global Engineering Documents.

Effective January 1, 2002.

Phone Orders: **1-800-854-7179** (Toll-free in the U.S. and Canada)
303-397-7956 (Local and International)
Fax Orders: **303-397-2740**
Online Orders: **www.global.ihs.com**

Date: ____________________

❏ **API Member** *(Check if Yes)*

Invoice To (❏ Check here if same as "Ship To")

Name:
Title:
Company:
Department:
Address:

City: State/Province:
Zip/Postal Code: Country:
Telephone:
Fax:
E-Mail:

Ship To (UPS will not deliver to a P.O. Box)

Name:
Title:
Company:
Department:
Address:

City: State/Province:
Zip/Postal Code: Country:
Telephone:
Fax:
E-Mail:

Quantity	Product Number	Title	SO★	Unit Price	Total
	Spec 10A	**API Specification 10A, *Well Cements***		**$ 97.00**	
	RP 10B	API Recommended Practice 10B, *Testing Well Cements*		**$ 142.00**	
	Spec 10D	API Specification 10D, *Bow Spring Casting Centralizers*		**$ 63.00**	
	RP 75	API Recommended Practice 75, *Development of a Safety and Environmental Management Program for Outer Continental Shelf Operations and Facilities*		**$ 102.00**	

❏ **Payment Enclosed** ❏ **P.O. No.** (Enclose Copy) ____________

❏ **Charge My Global Account No.** ____________

❏ **VISA** ❏ **MasterCard** ❏ **American Express** ❏ **Diners Club** ❏ **Discover**

Credit Card No.:

Print Name (As It Appears on Card):

Expiration Date:

Signature:

Subtotal	
Applicable Sales Tax *(see below)*	
Rush Shipping Fee *(see below)*	
Shipping and Handling *(see below)*	
Total *(in U.S. Dollars)*	

★ ***To be placed on Standing Order for future editions of this publication, place a check mark in the SO column and sign here:***

Pricing and availability subject to change without notice.

Mail Orders – Payment by check or money order in U.S. dollars is required except for established accounts. State and local taxes, $10 processing fee*, and 5% shipping must be added. Send mail orders to: **API Publications, Global Engineering Documents, 15 Inverness Way East, M/S C303B, Englewood, CO 80112-5776, USA.**
Purchase Orders – Purchase orders are accepted from established accounts. Invoice will include actual freight cost, a $10 processing fee*, plus state and local taxes.
Telephone Orders – If ordering by telephone, a $10 processing fee* and actual freight costs will be added to the order.
Sales Tax – All U.S. purchases must include applicable state and local sales tax. Customers claiming tax-exempt status must provide Global with a copy of their exemption certificate.
Shipping (U.S. Orders) – Orders shipped within the U.S. are sent via traceable means. Most orders are shipped the same day. Subscription updates are sent by First-Class Mail. Other options, including next-day service, air service, and fax transmission are available at additional cost. Call 1-800-854-7179 for more information.
Shipping (International Orders) – Standard international shipping is by air express courier service. Subscription updates are sent by World Mail. Normal delivery is 3-4 days from shipping date.
Rush Shipping Fee – Next Day Delivery orders charge is $20 in addition to the carrier charges. Next Day Delivery orders must be placed by 2:00 p.m. MST to ensure overnight delivery.
Returns – All returns must be pre-approved by calling Global's Customer Service Department at 1-800-624-3974 for information and assistance. There may be a 15% restocking fee. Special order items, electronic documents, and age-dated materials are non-returnable.
***Minimum Order –** There is a $50 minimum for all orders containing hardcopy documents. The $50 minimum applies to the order subtotal including the $10 processing fee, excluding any applicable taxes and freight charges. If the total cost of the documents on the order plus the $10 processing fee is less than $50, the processing fee will be increased to bring the order amount up to the $50 minimum. This processing fee will be applied before any applicable deposit account, quantity or member discounts have been applied. There is no minimum for orders containing only electronically delivered documents.

Additional copies are available through Global Engineering Documents at (800) 854-7179 or (303) 397-7956

Information about API Publications, Programs and Services is available on the World Wide Web at: http://www.api.org

American
Petroleum
Institute

1220 L Street, Northwest
Washington, D.C. 20005-4070
202-682-8000

Product No. G56001