

Report of the SPE Gulf of Mexico Deepwater Drilling and Completions Advisory Summit to NAE/NRC Committee

On March 17-18, 2011, the Society of Petroleum Engineers (SPE) sponsored a two-day summit to answer questions proposed by a National Academy of Engineering/National Research Council (NAE/NRC) panel examining Gulf of Mexico deepwater operations. The NAE/NRC committee, which has been asked by the U.S. Secretary of the Interior to identify ways of reducing the risk of incidents similar to the Macondo well blowout from occurring in the future, prepared a list of questions for consideration by the summit participants.

This SPE Technology Summit, titled “Gulf of Mexico Deepwater Drilling and Completions Advisory Summit to NAE/NRC Committee,” was attended by oil and gas industry professionals from operating companies, service companies, consulting companies, and academia. The participants were accepted based on their industry experience, and were explicitly asked to contribute their own views as engineers, not as advocates for their organization. A list of participants is included as an attachment to this report.

Summit participants met in five individual breakout groups and as a whole to discuss the questions. The responses in this report represent a consensus of the summit participants unless otherwise noted. One note on terminology: the use of the word “should” in this document means desirable, and does not imply a regulatory mandate.

A three-person committee helped organize the event and acted as facilitators: Ford Brett, Petroskills; Gordon Sterling, John M. Campbell & Co.; and James Pappas, Research Partnership to Secure Energy for America (RPSEA). Additional facilitators were Phil Grossweiler, M&H Energy Services, and William Pike, IBM (contractor to National Energy Technology Lab). Advisors to the summit were Ken Arnold, Worley Parsons, and Skip Ward, Texas A&M University.

Section 1: Oversight

1-1. What are the potential values and feasibilities of using a separate path of reporting and oversight for cost and schedule versus decisions affecting the integrity and safety of the well?

Summit participants do not believe there is value in using a separate path of reporting and oversight for cost and schedule versus decisions affecting the integrity and safety of the well.

Safety cannot be separated from operational decisions. Good safety practices and good business practices (including cost and schedule) go hand in hand. The industry has reduced occupational injuries in the past by integrating previously separated operations and safety reporting and oversight. Further improvements can be made in well integrity and process safety by applying similar integration principles.

By reporting, we mean organizational control and structure. By oversight, we mean responsibility and accountability.

1-2. To what extent should the oversight be performed by the companies themselves, independent third parties (e.g., classification societies), or regulators?

All three parties need to be involved in various levels of oversight. Company oversight should include a quality assurance process. The company is ultimately responsible for its safe operations. Independent third parties (both external and internal) have a role in providing specific expertise, broader industry perspective, and objectivity. Government regulators have a critical role in ensuring that all parties meet compliance obligations.

1-3. Should regulatory oversight be applied to the:

a. Development of processes themselves (e.g., ISO 9000 which is a consensus on good quality management practices)?

The government should not have oversight for development of processes themselves. Industry bodies should develop such processes and standards. Government regulators could participate in an *ex officio* capacity.

b. Selection of processes for a given well?

The government should not participate in the selection of processes (well plan) but should approve the proposed plan through the existing permitting process.

c. Execution of the processes?

The government should provide regulatory oversight for significant, risk-based, critical processes. Such processes could include safety and environmental

management systems [e.g., American Petroleum Institute Recommended Practice 75 (API RP 75) www.api.org/aboutoilgas/sectors/explore/safetymanage.cfm], well control management systems, and critical management processes (management of change). Regulator onsite auditing should be adequate for compliance assurance but should not be extended to continuous routine observation that adheres to existing recommended practices.

1-4. Are the same levels of rigor and attention to process safety needed for offshore drilling, onshore drilling, and refining? What are the most high-gain, leverage able opportunities?

The level of rigor and attention applied to process safety should depend upon a risk-based (frequency and consequence) analysis, not the type and location of the operation. High-risk operations require a greater degree of rigor and attention to process safety.

High-gain, leverage able opportunities include:

- Where well intervention is difficult
- Potential high-consequence areas
- Management of change
- Operational authority
- Lessons learned from OSHA process safety management standard
- Alarm management
- Process hazard analysis
- Contingency planning for worst-case scenario
- Proposed deepwater well design considerations (API RP 96, see www.api.org/Standards/standards-plan/index.cfm?renderforprint=1)

1-5. Does the industry have incentives to standardize technology? What areas of drilling practice are proprietary and/or give the most competitive advantages?

Operators, drilling contractors, and service companies have different incentives and areas of competitive advantage.

Operators have incentives to standardize technology. Operators consider few areas to be proprietary since they all use the same vendors. Some examples of operator proprietary practices include rate of penetration optimization and managed pressure drilling. But there are no barriers to safety standardization.

Drilling contractors and service companies have different business drivers. The long-term incentive to standardizing technology includes achieving lower cost and interoperability. However, two barriers to standardization of technology exist. The first is capital cost in replacing heritage equipment. The second is the drive to differentiate technology and service from competitors.

Many drilling practices are proprietary and offer competitive advantages to service providers and drilling contractors. Safety management practices are also a competitive advantage for drilling contractors and service providers.

1-6. Is adequate technical help made available from trained shore-based engineering or management personnel? How readily is it accessed by rig personnel to address the process risks inherent in drilling operations?

Adequate technical help is available. Technical help is frequently accessed by rig personnel. How readily it is accessed very often depends on how the organization executes its work flow and its management of change processes. There is a need to forecast and manage technical support for increased industry activity and to account for future retirements from the industry.

1-7. Information on “near misses” provides opportunities to improve management of risk and therefore:

a. What would be needed to develop a successful program for gathering important near-miss information?

A successful program for gathering important near-miss information requires a broad, inclusive, and common definition of “near miss”; an environment in which people are willing to report near misses without fear of reprisal; and identification of root cause(s).

b. Are the operating partner, non-operating partner, contractors, and service companies willing to share information about errors, omissions, and questionable results? If not, why not?

Operating partners, non-operating partners, contractors, and service companies are willing to share information about defined near misses within a project team and contract. As with most industries, the drilling industry is generally not willing to publicly share information about all errors, omissions, and questionable results because of the potential for liability, legal partner issues, competitive pressures, and unpredictability of court rulings and public interpretation.

1-8. Should the government have the right for oversight via real time communications on all critical wells?

No, because without context, data alone will not provide the capability to make informed decisions. However, for deepwater wells, data should be recorded offsite. Government regulators should be allowed to review data collected from real-time communications.

1-9. Should a government agency be responsible for setting standards for well planning, operational processes, and management of drilling operations?

The industry should develop the standard. Regulators should evaluate, vet, and incorporate by reference those standards as appropriate. Regulators could also participate *ex officio* in industry committees that are developing standards.

Section 2: Processes

2-1. What processes and approval requirements should be in place for:

a. Planning a well?

- Well design processes
- Risk identification/mitigation processes such as hazard and operability (HAZOP) and hazard identification (HAZID) analysis
- Change management process
- Team management process
- An approval process with sign offs

b. Approval of changes in plans?

- Well-design processes
- Risk identification/mitigation processes such as hazard and operability (HAZOP) and hazard identification (HAZID) analysis
- Change management process
- Team management process
- An approval process with sign offs

Should the processes be standardized?

No.

2-2. How do you define a critical well and should all such wells have real time onshore oversight and monitoring? Should all leaseholders have access to the real time data?

All deepwater wells are critical and every well is important, but certain wells may require increased evaluation and risk mitigation. The following well types and/or conditions have increased criticality in deep water:

- When formation pore pressure and fracture gradient is uncertain
- When well intervention is particularly difficult
- Offset wells when there is:
 - Where course of well grossly exceeds authorization for expenditure (AFE) associated with drilling trouble zones
 - Experienced well control near misses
- Almost all:
 - Critical sour wells
 - Wells in which extended-reach drilling is used
 - Sub-salt (presalt in Brazil) wells

Data should be collected and transmitted onshore 24 hours a day/7 days a week to ensure such information is available for analysis if needed. The operator should determine

whether onshore manned monitoring is warranted given mitigations available at the rig site and anticipated risk.

Summit participants saw no objection to access to real-time data but believe technical feasibility, especially with regard to varying data formats and transmission protocols, may be an issue.

2-3. To what extent are personnel performance bonuses (financial payments) tied to the occupational and operating safety performance?

Many engineering staff have safety as a component tied to their bonus. Most rigs have safety incentives for all employees. It is unclear the extent to which these bonuses are effective in driving safe behaviors or in creating a safety culture.

2-4. What are the potential advantages and disadvantages of complementing the existing regulatory system in the Gulf of Mexico with a safety case system?

Summit participants believe that current rules and regulations should be subsumed under a safety case regime. A safety case system (involving goal setting) would have several advantages and challenges.

Advantages:

- Would formalize risk assessment and management of change
- Would require management of change documents
- Would bring all parties together
- Would ensure compliance with approved well plans
- Would provide checks and balances for well planning (independently assessed)
- Would provide a greater chance for development and adoption of new technology
- Would be agreed to by all parties
- Would be a tool for effective communication

Challenges:

- Would require a change in thinking
- Competence assurance would be problematic
- Would require a culture change
- Would require an expanded level of competence
- Could take 5 to 10 years to fully implement

2-5. If it were to be adopted in the U.S., what modifications would be needed to how safety case systems are used in other parts of the world?

A safety case system for the U.S. should be compatible with existing safety case systems. Dialogue and cooperative discussion must take place with countries that have existing

safety case regimes—in particular the United Kingdom, Norway, and Australia—to craft a safety regime that is internationally compatible and allows operators to conduct global operations under a single set of safety standards.

2-6. What aspects of a safety case approach would ensure an effective focus on the likelihood of a blowout similar to the one at the Macondo well?

The Macondo blowout and ensuing disaster was a result of cascading failures in the design and management of the rig and drilling systems. A systemic approach to managing risk and ensuring safety should provide more focus on the risk of system failures as well as on the human factors that could contribute to an incident.

2-7. What improvements are needed in industry’s formal procedures for carrying out, interpreting, and approving critical tests such as a negative-pressure test? What protocols are needed for adapting tests to the configurations of a particular drilling vessel and BOP?

Improvements needed in the industry’s formal procedures for carrying out, interpreting, and approving critical tests include:

- Utilizing offsite transmission of digital records to obtain assistance and analysis if needed
- Standardizing procedures, reporting, and documentation

Vessels and BOPs need testing processes that are equipment specific and approved through a management of change (MOC) process as necessary.

2-8. Is there adequate monitoring of key operations on the rig? For example, are there adequate procedures to keep track of the material balance of the fluids in the well and riser? Is monitoring adequate for flow in and flow out during cementing operations?

No consensus was reached among the participants in the summit breakout group that discussed these questions. Two thirds of the participants thought the answer to the questions was yes and one third of participants thought the answer was no. All participants agreed that there was room for improvement.

Section 3: Responsibilities and Accountabilities

3-1. Who should be responsible and accountable for:

a. The final well plan?

The drilling engineer is responsible and the drilling manager is accountable.

b. Executing the well plan?

The team leader/superintendent is responsible and the drilling manager is accountable.

c. An unauthorized variation from the well plan?

The operator representative or lead representative or designated person (normally the drilling manager) in charge has both authority and responsibility for unauthorized variations from the well plan, and the offshore installation manager can shut down operations in emergencies if life or property is at risk. It is noted that “stop-work authority” is generally built into the plan.

As contingency plans are already determined along with the original well plan, the drilling manager should ultimately be accountable if an unauthorized variation from the well plan is not covered by a contingency plan.

d. Initiating a change in the well plan?

The team leader/superintendent is responsible and the drilling manager is accountable.

e. Getting the change approved?

The authority for getting change approved lies with the same level as indicated in parts 3-1.b (The team leader/superintendent is responsible and the drilling manager is accountable.) or 3-1.c, execution or variation, respectively.

However, participants thought the right question is: What level of change should initiate a formalized management of change (e.g., centralizers, cement)? The response to this question is: The operator still should be responsible. It is necessary to ensure the operator has a competent management of change process.

3-2. Should a non-operating partner, service company, or contractor be held accountable for not reporting a potential dangerous or hazardous operation or operational decisions?

The operator should absorb responsibility, so long as the drilling program has been approved. However, everyone on the rig is responsible for stopping a job if it is at risk and accountable if they do not report it. In addition, if any non-operating partner, service company, or contractor sees a pre-existing potentially dangerous or hazardous condition,

they have an obligation to object. Nonetheless, ultimately, the operator is always accountable.

It is unfair to hold the non-operating partner accountable if the joint operating agreement (JOA) does not allow the non-operating partner to have the facts. Service companies and contractors should have stop-work authority without fear of reprisal, in spite of a possible perceived conflict of interest.

3-3. Should there be a secondary company person (not a consultant) always on the rig to support the primary company person and assume the responsibilities in the event the primary person cannot fulfill his or her responsibilities?

There should always be two drilling representatives on the rig, not necessarily exclusively company people. The key is to have the best people for the job, whether they are hired as agents or they are employees. The most important thing is consistency—to have qualified, competent people who know and understand the company’s processes on the rig. Consultants can have a high level of expertise and local knowledge, are often available, and provide a rich experiential background that benefits the company through industry cross-fertilization.

3-4. It appears the master and offshore installation manager are held accountable and their licenses are at risk in an event like the Macondo blowout. Should this concept be extended to other personnel?

- The master and offshore installation manager are accountable. However, if the operator exerts pressure or power, does this undercut the accountability of the master and offshore installation manager? Their licenses are not necessarily at risk, since they are related to marine and maritime services. This is a US Coast Guard issue rather than a BOEMRE one.
- The real issue is the need for a consistent, industry-wide system of competency measurement. “Competency” needs to be defined and then tied to accountability.
- Everyone with authority or responsibility in 3-1 should have a *demonstrated competence*. A process should be in place to confirm competency (see Section 5 on training), which may include credentialing or other competency assessment. Competency assurance should indicate technical ability to perform the job.

3-5. Who should be accountable for a fault in the well plan, assuming the execution of the operation is carried out by the service company and/or contractor?

The management level at which the well plan is approved is accountable, if we define fault as what was known but not applied. But if a variation is due to an unforeseen natural

occurrence, then it is not a fault. There should be sufficient review of all plans so the drilling manager or designee can take responsibility. Operators have ultimate accountability. An example is new regulations (Code of Federal Regulations, Title 30, Part 250 at ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&tpl=/ecfrbrowse/Title30/30cfr250_main_02.tpl) that require cementing plans to be reviewed and signed off by a licensed professional engineer. Contractors are responsible for providing goods and services that meet agreed-upon specifications.

3-6. Should the operator’s safety performance be measured by including the safety performance of all rig personnel regardless of employer?

Absolutely. The safety performance of the entire rig personnel, including rig crew, should be measured.

(Note: currently there is not a consistent definition on how far to extend safety performance measurement beyond the drilling rig. There is not currently a consistent dividing line as to what should be measured and what should not. For example, one operator bases safety performance solely on that of the drilling rig, and a second operator might include crew boats and supply boats.)

Should contractors and service companies do the same? Should they be held to the same standards?

Contractors and service companies should include everyone under their respective authorities on the rig, including their onsite subcontractors, within the scope of their respective performance measurements.

3-7. Who is responsible for meeting statutorily prescribed responsibilities for health, safety, and the environment?

Each person is responsible—“You see it, you own it.” In fact, each person is responsible for themselves and for co-workers.

The question should also include the issue of accountability. BOEMRE clearly indentifies the operator as the accountable party. Accountability was clearly noted in question 3-1. above.

Section 4: Relationships Between Lease Holders (Operating and Non-Operating Partners), Contractors, and Service Companies

4-1. How can differences of opinion among the leaseholders (operating and non-operating partners) regarding operations be resolved in the operating agreement?

Joint operating agreements (JOAs) address the strategy for field development but generally do not cover the tactics at an individual well level. You could add some tactical level specifics to the JOA where a management of change process would require partner approval.

4-2.a. How should the operating partner, non-operating partners, contractors, and service companies respond to changes in the well plan?

It depends on the nature of the change. Minor changes are at the discretion of the operator. Major changes that involve scope or intent, or involve your partners, depend on the specifics in the JOA. There needs to be an understood and agreed multilevel management of change process that extends down to the prognosis level, which appropriately involves contractors and service companies (and extends to the operating level down to the permit-to-work level).

b. Should there be a formal operations change that is fully documented and approved?

Yes. There should be a management of change process that addresses change. In all of these cross relationships, there is a defined change and approval process for every appropriate level.

c. What type of documentation should there be for a change order and for the outcome of the operational change? It depends on the level of the change. The process should reach the accountable person or designee. That individual has the responsibility to review the cumulative effect of these changes on risk.

4-3. During drilling operations, who should have total control of the operations for:

- a. Normal drilling?**
- b. Running casing and cementing?**
- c. Operational problems with pipe in the hole? Logging? Testing?**
- d. Well control detection and response?**
- e. Other operations, i.e., directional drilling, fluid management, fishing operations?**

Summit participants almost unanimously agreed that the operator is accountable for the design and drilling of the well. At an operational day-in, day-out level, the operator can delegate responsibility to the drilling contractor and service companies for control of individual activities. The operator is ultimately accountable. For example, during a cementing operation, the operator normally delegates that responsibility to the selected service company; however, the operator retains ultimate accountability.

[Participants found the above question problematic because of the term “total control.” It was answered with the terms accountability and responsibility in mind.]

One participant also could not support the above response because of difficulty with the words “delegate responsibility.” He believes that “delegate responsibility” signifies a formal transfer of authority (as when a manager formally identifies a “delegate” in his absence). As such, operators cannot ever really delegate responsibility.

4-4. Under what circumstances should a non-operating partner be able to stop an operational decision from being implemented?

Anyone, including the non-operating partner, should have the right to stop the job at any time for consultation and re-evaluation when they believe there are significant health, safety, environment, or regulatory compliance risks. To the extent that the non-operating partner wishes to be involved in operational decisions, a mechanism for transmittal of information to the non-operator needs to be in place to allow for timely action. The communications protocol needs to be defined in the JOA.

4-5. Should a service company or contractor be willing and able to halt a potentially hazardous operation, i.e., to overrule the decision of the operating partner?

Summit participants almost unanimously agreed that the service company or contractor should be willing and able to halt an operation it deems to be hazardous. In the event of a disagreement between the operator and the service company or contractor on a specific risk, the service company has the right to refuse to perform the service.

The service company or contractor has the ability and obligation to raise an issue about a potentially hazardous operation.

One participant did not agree with the response above as worded and suggested the alternate response: The service company cannot “practically” overrule the operator, especially if there is a difference of opinion about items outside the scope of the contract. It is not a tenable position to refuse to work. For example, if the cementer identifies the number of centralizers as an issue, it would be very difficult to refuse to work.

Section 5: Personnel Training and Certification

Competency requirements are necessary and the path to that involves many parties and should be dealt with in a separate forum with adequate time to develop a framework. The industry needs time to think through these issues carefully to avoid unintended consequences.

5-1. What is your opinion of the relative value of formal educational background vs. expertise (on the job learning) vs. need for demonstrated competence for key roles?

When seeking those with recognized capabilities and experience, all three of these are valuable and they need to be factored in when assessing competency for key roles. The specifics of how this is done should be handled by a standard-setting body referred to here as a joint industry effort (see 5-9). Demonstrated competence is most important. There is no formal education degree program in the U.S. focusing on drilling sciences and drilling operational practices. Drilling engineering and operational practices are not generally taught at universities but are taught in the industry.

5-2. For well planning:

a. Should a registered and licensed professional engineer with some designated experience, or specifically demonstrated competence, or both in planning deepwater wells ultimately be responsible for the well plan?

The person who is ultimately responsible for well planning approval needs to have the degree, career experience and training to ensure a safe well design. Having a registered engineer may be valuable in the public perception, however, the reality is registered engineers may not focus on drilling engineering.

b. Who should set the experience standard or demonstrate competency standards?

We think there needs to be a joint industry effort (JIE) to establish competency standards (see 5-9.)

c. Should that engineer be independent of or employed by the operating partner, or either?

The person responsible for well plan approval should not be independent of the operator but should be an employee of the direct contractor of the operator responsible for the integrity of the well.

5-3. For operations:

a. Should both the company man and the lead person for the drilling rig contractor on the rig be engineers? Registered and licensed professional engineers?

An engineering degree for the company man and the lead person for the drilling rig contractor should not be required as long as they meet competency requirements. Non-engineering competencies (personnel management, total systems management) are also required to ensure operational reliability and safety. These are not necessarily attributes that a technical degree provides. An engineer will be available for operational support. Well reliability requires that total team makeup be managed in a way that competent engineering support is in place when needed.

b. What should be the experience requirement?

It should be a combination of years and project experience and the number of jobs worked. The details would be set by the joint industry effort (see 5-9).

c. Who should set the experience requirement?

This would be set by the joint industry effort (see 5-9).

d. Should there be demonstrated competency requirements?

Yes, this needs to take into account best practices, not lowest common denominator solutions.

e. Who should set the demonstrated competency requirements?

The joint industry effort (see 5-9).

5-4. Should the drilling manager(s) accountable for the drilling of an offshore well be an engineer? A registered and licensed professional engineer?

No. The well plan is currently reviewed and approved by a registered and licensed professional engineer.

5-5. Which key rig personnel should be licensed? If any, what agency should manage the licensing? What agency should enforce a loss of license?

The term “licensing” may not be a good description of how personnel competency standards would be managed. The philosophy of licensing should be determined by the joint industry effort (see 5-9). The joint industry effort should determine whether formal licensing procedures would be effective compared with setting standards measuring competency, education, and experience.

5-6. Considering the training of key rig personnel (e.g., operating company employees, consultants, employees or contractor and service companies):

a. Which key personnel should be required to take a meaningful amount of training each year?

That would be determined by the joint industry effort (see 5-9).

b. What amount should that be?

The focus should not be on the quantity because that does not ensure the relevant training needed to improve performance. Rather, there needs to be a meaningful connection between how things should be done on an offshore rig and systematic training linked to the competencies needed.

c. Should a global data base be established to document the history of training?

A worldwide data base may be desirable and should be considered by the joint industry effort (see 5-9).

d. If the training standard is not met, should the person not be certified to work on offshore wells?

Yes, as defined by the joint industry effort (see 5-9).

e. Should all drilling managers and supervisors have special training to maintain their positions? More training?

Yes, as defined by the joint industry effort (see 5-9).

5-7. Should all trainers and training centers be certified? If so, by what agencies, university, or other organizations?

The joint industry effort (see 5-9) should consider how the quality of the training material and the competency of the trainers should be verified.

5-8. Should there be a standardized training program and a required number of days on an offshore rig before an engineer can:

a. Be licensed to approve a well plan?

While summit participants agree that offshore experience is essential, under the current legal protocol concerning petroleum engineering approval of well plans, the petroleum engineering licensing process requires years of experience, thus adequate review of the well plan occurs under the current process. It is not necessary to require a specific number of days offshore.

b. Have some level of responsibility on the rig or to plan a well?

This should be considered by the joint industry effort (see 5-9).

5-9. What are your views on an institute on the lines of the Institute of Nuclear Power Operations, which covers standards for training, education, inspections, and safety culture for the nuclear industry?

Summit participants believe there needs to be a joint industry effort to establish competency standards. The Institute of Nuclear Power Operations (INPO) process may have useful attributes and should be considered along with other approaches. There are unique differences in the nuclear and oil and gas industries and all elements of the INPO framework are not directly applicable to the oil and gas industry.

5-10. How can training methods (such as use of simulation models) be improved for learning ways to respond to upset conditions?

The training needs to take a disciplined approach to what is needed to do jobs effectively. The joint industry effort should consider training programs that engage workers in realistic experiences to ensure that workers are capable of reacting to real world situations. This needs to deal with employee awareness of risk as well as technical skills. Computer animation may be a valuable adjunct to classroom training. But over time what once seemed striking becomes routine. The industry needs to continue to develop new training approaches to keep workers alert to the risks of finding and producing hydrocarbons.

Section 6: General

6-1. What other private initiatives regarding well drilling and completion should the committee be aware of?

The following are examples of organizations, among others, involved in preventative initiatives:

- American Petroleum Institute (API) (www.api.org)
- International Association of Drilling Contractors (IADC) (www.iadc.org)
- Offshore Operators Committee (OOC) (www.offshoreoperators.com)
- National Ocean Industries Association (NOIA) (www.noia.org)
- Research Partnership to Secure Energy for America (RPSEA) (www.rpsea.org)
- The International Regulators' Forum in Norway, Fall 2011 (www.irfoffshoresafety.com)
- International Association of Oil and Gas Producers' Global Industry Response Group (girg.ogp.org.uk)

An independent, self-auditing agency, similar to the nuclear power auditing agency, could be beneficial. Organizations such as the Marine Well Containment Company (www.marinewellcontainment.com) and the Helix Deepwater Containment System are involved in the response or mitigation side. In addition, there are several other initiatives, both public and private.

6-2. What specific recommendations should the committee consider for improvement of industry management?

Operators should second people to the BOEMRE and vice versa (as the marine industry and the Coast Guard do). Operators should pay for it. The benefits include the opportunity to teach and to learn from the seconded personnel.

There should be an independent, industry-wide capability that provides consistent, reliable feedback and develops best practices, at a minimum. They should not have a lobbying arm and should be populated with knowledgeable people from the industry. (Please see the discussion in question 5-9.)

Some participants felt it was not enough to ensure compliance with Safety and Environmental Management Programs (SEMS) and International Organization for Standardization (ISO) in order to achieve effective improvement of industry management.

6-3. What recommendations should the committee consider for regulatory oversight? Take into account the multiplicity of regulatory agencies; degree of consistency across regulatory requirements; and the extent to which they are based on an adequate understanding of the technology, personnel, and operations.

BOEMRE needs to improve on the following:

- Consistency from one district to another in the Gulf of Mexico
- Additional expertise, in both quality and number of individuals
- Communication and consistency between regional offices and Washington headquarters