DEPARTMENT OF ENVIRONMENTAL CONSERVATION

DIVISION OF SPILL PREVENTION & RESPONSE

OIL DISCHARGE PREVENTION & CONTINGENCY PLAN REGULATION REVISIONS

PUBLIC NOTICED SEPTEMBER 8, 2003 – OCTOBER 13, 2003

RESPONSE TO COMMENTS

MAY 14, 2004

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1. Introduction

The Alaska Department of Environmental Conservation is engaged in a multi-year project to evaluate changes to 18 AAC 75 relating to oil discharge prevention and contingency plans. Phase 1 of the project was dedicated to oil exploration and production facilities.

A. Summary of Contingency Plan Regulation Project Phase 1

As stated in the public notice of proposed regulation, the objective of this phase of the Contingency Plan Regulation project was to:

> "... change existing oil discharge and contingency plan (C-plan) requirements to reduce[ing] ambiguity or possible conflicting interpretations and to improve clarity. For oil exploration and production facilities, these changes include clarification of the response planning standard, response strategy and scenario requirements, and realistic maximum response operating limitations. DEC is also clarifying the distinction between its statutory obligations and those of the Alaska Oil and Gas Conservation Commission (AOGCC) with regard to oil exploration and production. For example, proposed changes are intended to recognize that, with respect to blowout risk, AOGCC is the agency that determines the blowout prevention measures that an operator must implement in order to receive a permit to drill. DEC's primary obligation is to ensure that an operator takes specific measures to prevent and be prepared to respond to spills from the operation once a permit to drill has been issued."

Current contingency plan regulations became effective in 1992 after passage of more stringent oil spill statutes following the Exxon Valdez oil spill. With the exception of 1997 amendments requiring spill prevention and response Best Available Technology (BAT) evaluations, the regulations have remained unchanged since 1992.

Exploration and production facility contingency plans prepared under the existing regulations have led to substantial improvements in oil spill preparedness and response capability in Alaska. However, ambiguities and lack of well-defined standards have led to adjudication and litigation, frustrating the regulated community, other stakeholders, and the Department. These contingency plans have been the subject of repeated challenges to past Department decisions. There is substantial stakeholder and plan holder interest in re-examining the existing requirements to identify improvements while maintaining their effectiveness and consistent application.

The Alaska Department of Environmental Conservation (ADEC) issued a "strawman" discussion draft of proposed changes to 18 AAC 75 relating to oil discharge prevention and contingency plans for oil exploration and production facilities on April 24, 2003. The Department then conducted an informal 60-day public notice of this discussion draft. Two public workshops were held to discuss the proposed changes during this period, one in Anchorage (May 16, 2003) and one in Barrow (June 17, 2003). A website was also set up at http://www.state.ak.us/dec/spar/ipp/cpr/cprhome.htm. The initial public notice period for the discussion draft ended on June 25, 2003. After reviewing the comments received during this period, many changes were made to the discussion draft and a revised draft of our proposed regulations was formally public noticed on September 8, 2003. The formal public notice was advertised in the Juneau, Anchorage, Kenai, Barrow, and Fairbanks newspapers. Following a 30 day formal public comment period, we refined the proposed regulations once more before proposing final regulations.

The comments and issues addressed in this summary are in response to the 30-day comment period and contain the rationale for the final changes to the regulations. The Department considered all comments received and, in some cases, made revisions to its proposed regulatory changes.

B. Organization of this Document

This document is organized in a comment/response format to address issues raised during the formal public review period. Proposed regulatory changes that are primarily technical in nature or did not elicit direct substantive comments are not generally addressed in this document. Likewise, issues that were fully addressed as part of the response to comments from the informal public review of the strawman document are also not generally addressed in this document.

For clarity and ease of understanding, specific comments received on the public comment draft are grouped together and addressed in order under the corresponding proposed regulatory change. Comments of a more general nature or those that addressed issues beyond the scope of the discussion draft are discussed at the beginning of this document.

2. Issues Relating to Regulation Drafting Process

Comment

Some commenters suggested withdrawing the proposed regulations and issuing a second set of proposed regulations for public review before final adoption. The commenters felt that the proposed regulations did not fully meet their expectations of improved clarity and reduction of ambiguity.

Response

The Department recognized the scope and complexity of the project early on and the need for extensive input and actively solicited feedback through an informal comment period and a formal public notice period. We made several significant changes to the proposed regulations based upon input from the public during this project. Because of the wide range of comments, not all comments could be fully accommodated in our revisions. The Department believes that the proposed changes meet the objectives identified in the public notice.

Comment

Some commenters requested wording changes, substituting “will”, “shall”, “must”, or other wording in lieu of the proposed regulation language.

Response

The Department followed the *Alaska Drafting Manual for Administrative Regulations* during the regulation drafting process. The wording of the regulations reflects present usage as defined in the manual.

3. Issues Outside the Scope of Phase 1 of the Contingency Plan Regulations Project

A. General

A number of comments were received which the Department considers to be outside the scope of this phase of the project. Some comments are being retained for future consideration.

B. Departmental Discretion

Comment

Several commenters felt that the proposed regulatory changes continue to rely too much on Departmental staff discretion for judging regulatory compliance instead of providing sufficient regulatory consistency and clarity.

Response

An effective contingency planning process is location and facility specific, and as such, cannot be fully described by prescriptive regulation alone. Some level of Departmental discretion will always be required to handle unique location-specific situations and to judge compliance with performance based standards. The level of discretion retained in the proposed regulations is appropriate to accommodate the large variation in facility type, location, and receiving environment.

C. Deterministic Models & the Use of Equipment Tables

Comment

Several commenters supported the use of deterministic or “look-up” tables to determine the appropriate level of response resources to meet Department requirements, instead of having the response planning standard (RPS) scenarios driving the amount of response equipment required to meet Department requirements.

Response

In the Department's public notice of our proposed changes to the regulations we stated that the purpose of the changes was to reduce ambiguity or possible conflicting interpretations and to improve clarity. For oil exploration and production facilities, these changes include clarification of the response planning standard, response strategy and scenario requirements, and realistic maximum operating limitations. The proposed scope of changes did not include development of deterministic or "look-up" tables.

The Department also believes that developing a prescriptive set of equipment requirements for the diverse suite of regulated facilities, railroads, tank farms, pipelines and vessels would be a complex task requiring significant time and effort, and would limit the flexibility operators now have to determine their own mix of equipment tailored to their particular situation. This approach would also entail a fundamental shift in the existing contingency plan requirements affecting all regulated operators. The Department's goal is to establish clear, protective standards while allowing the flexibility for operators to select and optimize the equipment that best meets the needs of their facility.

Although the Department believes that the response planning scenario remains the best means of judging compliance with current requirements, the Department will continue to consider ways to move toward a more prescriptive approach where possible to enhance clarity and certainty in regulatory compliance.

D. Drill & Inspection Program

Comment

One commenter requested regulatory language requiring implementation of an aggressive drill and inspection program, especially regarding well control plans.

Response

The Department fully agrees that a fully implemented drill and inspection program is a key component of an effective oil spill prevention and response program. The Department has committed to increasing the number of drills and inspections as a response to the change in contingency renewal period from three to five years.

E. General Prevention Requirements

Comment

Several commenters felt that spill prevention requirements were not addressed, or not addressed adequately, in the proposed regulations.

Response

The Department did not intend to fully address prevention requirements in this phase. As noted in the Department's issue paper of April 24, 2003, prevention requirements will be dealt with as a separate phase of the overall contingency plan revisions. The comments received during this phase of the contingency plan regulations project regarding pollution prevention requirements will be retained for consideration in the next phase of the contingency plan revisions.

Originally, prevention regulations were scheduled to be addressed as phase 3 of the contingency plan regulations project. Due to the comments received during the public comment periods, the Department has rescheduled prevention measures as phase 2 of this project, acknowledging the importance of the topic.

F. Nonmechanical Response Requirements

Comment

Several commenters requested revisions to the regulations to ensure that plan holders complete the requisite pre-planning required for successful implementation of nonmechanical response options.

Response

The Department agrees that the nonmechanical response requirements should be reviewed, but the requested revisions are outside of the published scope of the proposed rulemaking. The revisions will therefore be fully addressed as part of a subsequent phase of this project.

The Department notes that nonmechanical response presently requires application through the regional response team (RRT) framework for the appropriate permits to implement nonmechanical response options. The RRT review process and Unified Command structure adequately addresses this concern.

G. Incorporation of 1997 North Slope Planning Assumptions

Comment

Several industry commenters requested inclusion of the 1997 North Slope Planning Assumptions contained in the Industry/Agency North Slope Oil Spill Response Guidance for Preparing Marine Response Scenarios, dated March 1999, into regulation as regulatory guidance for development of scenarios required by 18 AAC 75.425(e)(1)(F). The assumptions cover certain aspects of the following variables:

1. Blowout oil lost to evaporation from wells producing more than 5,500 bbl/day
2. Blowout discharge rate from existing production wells
3. Blowout discharge from new reservoirs
4. Duration of planning period for a blowout
5. Out-of-region resources
6. Maximum wind speed
7. Directional persistence of wind
8. Maximum wave height in mature fetch
9. Ice coverage during broken ice periods
10. Oil-to-water ratio of emulsion for storage purposes
11. Portion of oil entering open water
12. Slick size
13. On-water trajectory
14. Safety zone boundary (permissible exposure limit, PEL)
15. Encounter rate
16. Derated oil recovery rate for skimmers
17. Throughput efficiency (boom containment)
18. Advancing skimmer speed
19. Barge storage capacity
20. Utilization time of recovery systems
21. Mini-barge fill time (with weir skimmer and 2 decants)
22. Vessel and barge transit time
23. Mini-barge offload time
24. Decanting from barges
25. Delivery mixture from 249-bbl mini-barge coupled with weir skimmer

Response

The Department has included the relevant planning assumptions into the revised regulations. Incorporation of the 1999 assumptions in total is considered inappropriate due to the following constraints:

- The 1999 assumptions were written as being general guidance only, specific to marine response for the North Star offshore facility development.
- The use and applicability of the 1999 assumptions is limited and they have been considered on a case-by-case basis as part of the plan review process.
- As proposed by the commenters, the proposed assumptions do not include revisions to the original 1999 assumptions based upon the results of response exercises and further planning assumption development.

- Of the 25 assumptions, many are for open water containment and recovery, and would be applicable to all locations and facilities.

The Department does not agree that every parameter of oil spill contingency planning can or needs to be set out in regulation and that the Department may appropriately set such parameters or details during the plan approval process.

Additional discussion of this comment is contained in Appendix 1 of this document.

H. Incorporation of Risk with Respect to Oil Spills

Comment

Several commenters felt that the regulations fail to appreciate and include the concept of risk in the contingency planning process.

Response

AOGCC, and the U. S. Minerals Management Service (MMS) for federal areas, have a risk analysis built into their leasing and permitting regimes. If AOGCC has permitted an exploration or production well, then the risk of an oil spill has been clearly addressed through the AOGCC regulatory permit process, which includes a risk analysis and imposition of specific prevention measures to reduce the risk of a discharge.

There is a significant distinction between the statutory obligations of AOGCC and the Department regarding oil exploration and production operations. With respect to risk, AOGCC is the state agency that determines the risk of an oil discharge and what specific permit stipulations will be imposed to reduce the risk to a level acceptable to the state in order for a permit to be issued. The Department's primary obligation is to ensure that an operator takes specific measures to be prepared to effectively respond to spills from the operation once a permit to drill has been issued.

The Department agrees that well blowouts are discrete, low-probability events, but also notes that such events have significant consequences to the environment. The Department's contingency planning regulations are designed to deal with the consequences of an oil discharge and their mitigation, on the assumption that the risk probability element has been sufficiently addressed during the permitting process. The response planning standard requirements require a planned response to a realistic maximum oil discharge, the maximum discharge that the department estimates could occur given an analysis of historical data and operation-specific considerations such as size, location, and capacity. The response planning standard is not predicated on probability or risk but rather consequences. This is a statutory obligation and one that cannot be changed through a regulation revision.

I. Incorporation of Traditional & Local Knowledge

Comment

One commenter proposed additional regulatory language to specifically require incorporation of traditional and local knowledge into the contingency plan development and review process.

Response

The Department believes that the plan holder should use all available resources in developing scenarios and response strategies, including traditional and local knowledge, and that the present contingency plan development and review process allows for sufficient public comment to incorporate traditional and local knowledge. The Department notes that other regulatory agencies involved in permitting oil exploration and production facilities, such as the Alaska Oil and Gas Conservation Commission (AOGCC) and the U. S. Mineral Management Service (MMS), incorporate significant local input in their leasing and permitting processes, including stipulations on leases to incorporate traditional and local knowledge, and those permits are a required precursor for a contingency plan approval.

J. Cooperation and Coordination with Local Governments and Tribes

Comment

One commenter proposed additional regulatory language to specifically require plan holders to demonstrate compliance with local regulations and policies, and that local concerns have been met prior to submission of a contingency plan application to the Department.

Response

The Department disagrees with the proposed changes. Requiring local review of a contingency plan to determine compliance with local regulatory permits and stipulations before application to the Department is a local government regulatory function and would be duplicative of the public review process.

K. Updating the Contingency Plan Application & Review Guidelines

Comment

Several commenters requested that the Department update the July 1994 application and review guidelines or provide additional guidance and interpretation of the regulations.

Response

The Department agrees that the application and review guidelines need to be updated and we have planned do so as part of a separate project.

L. Region specific requirements

Comment

One commenter requested that the Department develop specific regulations for arctic environments. Another commenter requested that the Department require Cook Inlet plan holders to prepare a winter scenario that accounts for the likely presence of broken ice.

Response

The Department believes that the approval criteria of 18 AAC 75.445 and the review procedures of 18 AAC 75.455 are sufficiently adequate to account for regional variations in operations.

Regarding the request for Cook Inlet plan holders to prepare scenarios that account for broken ice, the Department notes that several of the Cook Inlet plan holders already have winter broken ice scenarios in their approved contingency plans.

M. Sub-sea Multiphase Piping

Comment

One commenter requested that the Department clarify that sub-sea multi-phase piping is regulated under 18 AAC 75.080 during the next phase of this project.

Response

The Department has noted this comment for future rulemaking consideration.

4. Issues Relating to Contingency Plan Applicability (18 AAC 75.400)

A. Consolidated Contingency Plans for Multiple Facilities

Comment

One commenter expressed concern that allowing consolidated contingency plans could lead to large, unmanageable plans that would be difficult to review.

Another commenter requested that the consolidation of plans be geographically-based, allowing multiple operators to have one plan.

Response

The Department believes that consolidating multiple similar facilities of a single operator will reduce the review burden and lead to planning efficiencies for plan holders. This consolidation of contingency plans has already happened successfully in practice with some exploration facility operators.

Regarding the concept of multiple operators submitting a single contingency plan to cover multiple operators, state statutes and regulations appear to prohibit this. However, multiple plan holders may reference a separate outside document to meet specific items in a plan holder's contingency plan. For example, the CISPRI technical manual may be utilized by many plan holders to satisfy the regulatory requirements of 18 AAC 75.425(e)(1)(F) for a response action plan to the extent that it sufficiently meets the plan holder's regulatory requirements for contingency planning.

5. Issues Relating to Contingency Plan Contents – Part 1 (18 AAC 75.425(e)(1))

A. General

The changes proposed for 18 AAC 75.425(e)(1) are predominantly centered around scenario development and well control. Both issues have been contentious in the past, and a large number of comments were received from the public as part of the public review process. The goal of the Department was to clarify the number and quality of the scenarios required by regulation, and to revise the well control requirements to bring them in line with proposed changes in 18 AAC 75.434 and improvements in well control technology.

In order to clarify requirements for exploration and production facilities, the information specific to response scenarios for exploration and production facilities has been consolidated in a new section, 18 AAC 75.425(e)(1)(I).

B. Number of Scenarios Required Under 18 AAC 75.425(e)(1)(F)

Comment

Several commenters wanted the number of spill response scenarios to be capped to an arbitrary number (six was suggested as an appropriate number). The commenters felt that not capping the number of scenarios could lead to an increase in the number and complexity of the scenarios. The commenters felt that there was too much Departmental discretion without an upper limit.

Response

The Department contends that capping the number of scenarios would severely limit the Department's ability to adequately assess a plan holder's capability to respond in varying environmental and meteorological conditions. The Department notes that several contingency plans already have more than six scenarios in them, due to the wide range of receiving environments that could potentially be impacted by a spill from the plan holder's facilities (the Trans Alaska Pipeline System contingency plan and the Alaska Railroad Corporation contingency plan are two examples). Limiting the number of scenarios would also effectively inhibit the consolidation of multiple operations under a single plan, such as the exploration well plans currently in place on the North Slope. In these cases it is a great benefit to plan holders to be able to reduce the number of plans even though it is appropriate to have additional scenarios to cove the wider range of receiving environments. Scenarios requirements are proportional to the scale and extent to which facilities may be consolidated into one plan. The Department also notes that this change effectively captures current practice regarding the number of scenarios necessary to adequately assess a plan holder's spill response capability.

The development of appropriate scenarios is a key element in successful contingency plan development under the regulations, since the scenario is the method by which adequacy of response resources and strategies is judged. The Department has revised 18 AAC 75.425(e)(1)(F) to clarify what the Department considers an appropriate level of detail in a response scenario.

Comment

One commenter indicated that the additional scenarios change was too open ended, and that many facilities and response action contractors have already defined a number of tactics that should suffice to meet the requirement.

Response

The Department has included language that allows tactics and strategies located in a separate document, such as a technical manual or field guide, to be referenced as part of the scenario, on the condition that the referenced material is acceptable to the Department and germane to the scenario. The Department agrees that, for many fixed facilities that have operated under the existing regulations for a significant period of time, tactics and strategies have been well-developed and tested. The Department does not anticipate any substantive changes to contingency plan scenarios for these plan holders.

C. Time Period to Control a Well (18 AAC 75.425(e)(1)(F)(iii)/(e)(1)(I))

Comments

Several commenters indicated that a 15 day planning standard would be construed to be a performance standard by plan holders. Two commenters requested an aggressive implementation of a 15-day planning standard for control of a well blowout.

Response

The Department requires that the plan holder has a blowout contingency plan to control a well blowout within 15 days. The operator is expected to implement the blowout contingency plan in the event of a spill. However, this is a planning standard, not an enforceable performance standard for response to an oil discharge.

The contingency plan requirements of 18 AAC 75 Article 4 are response planning standards designed to meet the response planning requirements of AS 46.04.030, specifically AS 46.04.030(k) in this instance.

AS 46.04.030(l) explicitly states that the provisions of AS 46.04.030(k) are not performance standards.

> "AS 46.04.030 Oil Discharge Prevention and Contingency Plans.
>
> (l) The provision of (k) of this section do not constitute cleanup standards that must be met by the holder of the contingency plan..."

The Department believes that a well-designed well blowout control plan would describe multiple options for bringing a well under control depending upon the circumstances of the loss of well control. The various options would be associated with various timeframes, depending upon the characteristics of the wells and their location. In all cases, the operator should plan for contingencies such that positive well control should be regained within the 15 day planning standard. The Department notes that this is well within historical timeframes for past incidents of loss of well control for operators operating under U.S. regulatory regimes or equivalent regulatory regimes of other industrialized nations.

The Department also emphasizes that the 15 day planning standard for well control does not equate to a 15 day response planning scenario. An approved contingency plan will describe planned response actions for the duration of the response scenario, until the cessation of spill response activities and the start of spill remediation activities.

In order to consolidate and clarify the requirements for exploration and production facilities, the information in 18 AAC 75.425(e)(1)(F)(iii) has been relocated to a new section, 18 AAC 75.425(e)(1)(I), along with other requirements specific to response scenarios for exploration and production facilities.

D. Well Blowout Control Plan (18 AAC 75.425(e)(1)(F)(iii)/(e)(1)(I))

General

In order to consolidate and clarify the requirements for exploration and production facilities, the information in 18 AAC 75.425(e)(1)(F)(iii) has been relocated to a new section, 18 AAC 75.425(e)(1)(I), along with other requirements specific to response scenarios for exploration and production facilities.

Comment

Several commenters requested that the well blowout control plan be made available to the public as part of the public review process.

Response

The Department has modified the proposed language to increase the amount of well blowout control information that would be available for public review to a level sufficient for public involvement in the approval process. The proposed language would require

> "a summary of planned methods, equipment, logistics, and timeframes proposed to be employed to control a well blowout within 15 days; the plan holder shall certify that the plan holder maintains a well blowout contingency plan; the well blowout contingency plan is not part of the contingency plan but shall be made available to the department for inspection upon request under 18 AAC 75.480."

This summary of the planned methods, equipment, logistics and timeframes proposed to be employed to control a well blowout within 15 days will provide sufficient information within the contingency plan to determine compliance with state contingency plan approval requirements and will provide necessary information to the public during the public review process under 18 AAC 75.455.

The Department does not agree that every technical document implementing a contingency plan needs to be reviewed as part of the formal plan. The Department believes that requiring technical "plans within a plan" distracts the contingency plan review process from the real regulatory issues surrounding contingency plan approval. The Department, does however, have the ability to inspect the well blowout contingency plan as part of its compliance activities under 18 AAC 75.480.

Comment

Several commenters requested that the Department maintain the existing requirement for a plan to drill a relief well, as a baseline well control option.

Response

As the Department has previously noted, the well blowout control plan requirement does not preclude planning for a relief well. Indeed, a well-designed well blowout control plan would include drilling a relief well as one of several well control options. The purpose of the proposed change is to expand the number of options for controlling a well blowout, and to ensure that there is a plan designed to bring a well blowout under control within the 15 day planning period. Based upon past experience with contingency plans and a Department analysis of well blowout control technologies, plan holders shall plan to be able control a well blowout within 15 days, by whatever method is most appropriate in the specific situation to meet the planning standard established in this regulation.

The supporting documentation for the original contingency plan regulations in 1992 clearly indicate that the Department believes that it is consistent with the statutes to provide for preventing and controlling a blowout in the shortest possible time. The purpose of replacing the requirement for a relief well with a summary of planned methods, equipment, logistics, and timeframes to control a well blowout within 15 days is to recognize that there are multiple methods of controlling a well, some of which may initially bring a well back under positive control more quickly than drilling a relief well.

Comment

One commenter requested a change in the wording from "method" to "methods", noting that no single method can accommodate all potential situations.

Response

The Department agrees with the comment and has revised the wording.

E. Seasonal Variations (18 AAC 75.425(e)(1)(I))

Comment

Industry commenters were concerned that the proposed scenario inputs for response planning standard (RPS) scenarios failed to list the large number of variables required to develop a spill scenario and response strategies. Several comments requested full inclusion of the 1997 North Slope planning assumptions into regulation.

Response

The Department included basic weather data for two RPS scenarios to account for areas where seasonal variation significantly affected the character of an oil spill response for exploration and production facilities. It is not the intention of the Department to spell out in great detail in the regulations the full range of inputs into spill scenarios. Spill scenarios are by nature facility and location-specific, and the appropriate scenario conditions vary greatly among the regulated community. As noted in a previous section in this document, the Department has incorporated certain relevant spill scenario planning assumptions into the regulations where appropriate. The Department does not agree that every parameter of oil spill contingency planning can or needs to be set out in regulation and that the Department may determine appropriate scenario input parameters during the plan approval process.

Comment

On commenter noted that the six-month periods do not properly reflect seasonal conditions in Alaska and particularly on the North Slope. The commenter suggested narrowing the summer period from April through September to June through September. The lengthy winter season is the remaining period October to May.

Response

The two six month periods were developed to provide a basis for average weather conditions as an input into scenario development, not to indicate that there are only two seasons. The regulations clarify that, for exploration and production facilities in areas that require disparate response techniques at different times due to environmental factors, the Department may require an additional RPS scenario, and defines what environmental inputs shall be used for scenario development. This does not relieve the plan holder from the requirement of 18 AAC 75.425(e)(1)(f) for additional non-RPS strategies to account for variations in receiving environment.

Regarding the disposition of the six month average planning periods, the Department has modified the start and end dates of the two time periods in recognition of the public comments.

F. Use of Computer Models (18 AAC 75.425(e)(1)(I))

Comment

One commenter felt that it was inappropriate to specifically call out a particular computer model, and several commenters thought that the S.L. Ross model did not meet the Best Available Technology (BAT) standards of 18 AAC 75.425(e)(4).

Response

The Department notes that the regulation allows the use of computer models other than the S.L. Ross model. The S.L. Ross model was included due to the fact that it has already gone through a review by the Department and is currently utilized in several approved contingency plans, but plan holders are free to submit other models. The Department also notes that the BAT requirements of 18 AAC 75.425(e)(4) do not apply to scenario development and that therefore the use of computer models in scenario development is not subject to a BAT analysis.

Comment

Some commenters requested that a complete list of inputs into a computer model be incorporated into the regulations. These comments were in conjunction with the previous comments regarding seasonal variations.

Response

The Department notes that a computer model is just that – a model, a rough approximation of reality with many limitations and constraints. The appropriate and effective use of a computer model for scenario development is a complex operation that depends upon judicious selection of the appropriate model, appropriate input data, the appropriate number of model runs, and correct analyses and interpretation of the model results. Departmental specification of global model inputs is inappropriate given the range of models, scenarios, and available input parameters. The plan holder and modeler are the appropriate compilers of data for input into a computerized scenario model.

Comment

One industry commenter noted that, while the Department proposes to allow the use of other oil spill models, the proposed regulations are silent on approval criteria for models other than the S.L. Ross model.

Response

The Department contends that acceptance of specific oil spill models must be made on a case-by-case basis, dependent upon the applicability of a specific model to a specific location and operation. Models vary widely in complexity, applicability, and features, and it is inappropriate to attempt to make blanket criteria for their use. The Department also notes that the accuracy and suitability of a given model is highly dependent upon the correct selection of input parameters, model operation, and human analysis of the output.

6. Issues Relating to Contingency Plan Contents – Part 2 (18 AAC 75.425(e)(2))

A. General

No substantive comments were received regarding the proposed changes.

7. Issues Relating to Contingency Plan Contents – Part 3 (18 AAC 75.425(e)(3))

A. General

The changes to 18 AAC 75.425(e)(3) are designed to revise realistic maximum response operating limitations and to provide additional clarification of response equipment requirements, and protection of environmentally sensitive areas.

B. Realistic Maximum Response Operating Limitations (18 AAC 75.425(e)(3)(D))

Comment

One commenter requested changes to the wording to clarify that compensating measures other than nonmechanical response may be equally effective and to emphasize that the use of nonmechanical response options during realistic maximum response operating limitations (RMROL) would be predicated on demonstrating that they can be effective at those conditions and are subject to the requisite permitting and approval process.

Response

The Department makes no blanket claim regarding the effectiveness of any specific measure during RMROL conditions. The appropriateness of a measure is dependent upon the specific attributes of the facility and the specific environmental and safety conditions that preclude the effectiveness of mechanical response. The approval requirements of 18 AAC 75.445(f) provide sufficient criteria for demonstrating the appropriate applicability of nonmechanical response options during periods of RMROL.

The non-mechanical response option requirements of 18 AAC 75.425(e)(3)(G) require that any non-mechanical response options must meet the requisite permit and approval requirements.

Comment

One commenter noted that the proposed regulations did not indicate how the Department will calculate the use of non-mechanical response options when determining whether a plan holder can meet their individual response planning standards (RPS).

Response

RMROL and RPS are two separate independent concepts. By statute, the plan holder must meet their RPS using mechanical recovery options, and shall describe, using a scenario, how they would contain, control, and clean up a spill of the RPS volume using mechanical recovery options during typical environmental conditions.

RMROL is that regime of physical conditions where, due to environmental or safety reasons, mechanical recovery is not feasible. During those conditions, the Department requires that the plan holder plan for compensatory measures, such as non-mechanical response options, seasonal drilling restrictions, voluntarily curtailment of certain activities, and other prevention measures, in order to reduce the environment consequences of an oil discharge during RMROL conditions. These requirements are in addition to, and separate from, the RPS mechanical recovery requirements.

Comment

One commenter stated that the proposed regulation elevates non-mechanical response from an option to a requirement without rules for its use. The proposed regulations also do not provide for credit towards attaining the response planning standard for the non-mechanical response capabilities.

Response

The proposed regulations do not require a non-mechanical response, but allow it as an option to reduce the consequences of the plan holder's inability to effectively utilize mechanical response methods during RMROL conditions.

The proposed regulations do not provide credit towards the RPS for non-mechanical response methods because the RPS must be met by mechanical response methods only, and RMROL is, by definition, that environmental or safety regime where mechanical response methods are ineffective, outside of the regime of the RPS and RPS scenarios. Any proposed use of non-mechanical response options as a compensating measure during RMROL conditions will be evaluated on a case-by-case basis as to its appropriateness for the given conditions. As an example, the proposed use of dispersants or in-situ burning must meet the guidelines developed by the Alaska Regional Response Team (ARRT) and other federal and state requirements.

Comment

One commenter requested clarification that seasonal drilling restrictions (SDRs) are the appropriate prevention measure during RMROL periods and the specific inclusion of SDRs in regulation.

Response

Seasonal drilling restrictions or other temporary cessation or reduction in activity may be effective potential measures to compensate for RMROL conditions, and may be appropriate in certain instances.

The question of whether or not a facility may operate, from a risk management perspective, is not within the statutory obligation of the Department. As noted earlier in this document, AOGCC has the statutory responsibility to determine whether an operator has managed risk sufficiently to receive a permit to operate. The responsibility of the Department is to ensure that, if a permit is in place, a sufficient response capability exists to manage the environmental consequences of a discharge from the facility. It is not within the Department's authority to determine an acceptable level of environmental risk of an operation.

In the past, seasonal drilling restrictions have been imposed by other permitting authorities to reduce environmental impacts (e.g., Minerals Management Service (MMS) permit stipulations to prevent impacts to migrating bowhead whales) and have also been voluntarily proposed by plan holders to the Department (e.g., BP Exploration's voluntary seasonal drilling restrictions during broken ice and open water conditions).

Comment

One commenter requested specific regional seasonal drilling restrictions, similar to drilling restrictions in Bristol Bay and the Kenai River Special Management Area, be written into regulation.

Response

The Department notes that the Bristol Bay drilling moratorium, like the moratorium on drilling in the Alaska National Wildlife Refuge 1002 area, was the result of Congressional action , not Departmental regulation, and that the Kenai River Special Management Area restrictions were established by the Alaska Legislature not by the Department under contingency plan regulations. None of restrictions noted by the commenter are examples of seasonal drilling restrictions imposed by the Department.

Comment

One commenter stated that statutory intent (AS 46.04.030(m)) required the use of specific temporary prevention measures during RMROL, and that use of nonmechanical response options during RMROL was in conflict with the intent of the statutes.

Response

The Department disagrees with the comment that the use of non-mechanical response options during RMROL conditions is inconsistent with DEC's enabling statutes. AS 46.04.030(m) does not address RMROL conditions.

Rather, AS 46.04.030(m) allows for reduction in the response planning standards in AS 46.04.030(k) for specific voluntary oil discharge prevention measures that the Department believes would reduce the risk or magnitude of a discharge. Although AS 46.04.070 provides authority for DEC to require prevention measures in regulation, AS 46.04.030 does not require specific prevention measures during RMROL conditions as part of the contingency plan review. The Department believes it has achieved an appropriate balance in its clarifications to the RMROL regulations.

C. Response Equipment for Protection of Environmentally Sensitive Areas (18 AAC 75.425(e)(3)(F))

Comment

One commenter requested additional clarification on how the Department plans to enforce the sensitive area protection requirement, particularly as it applies to determining which geographic response strategies (GRS) might be triggered during an RPS spill scenario and assessing the adequacy of the GRS implementation.

Response

The Department has revised the wording to indicate that protection of the environmentally sensitive areas that may be reasonably expected to be impacted by a spill of the RPS volume as described in the plan holder's scenario must be planned for in the contingency plan.

Comment

One commenter requested clarification that the response equipment listed as used for protection of environmentally sensitive areas is not precluded from use to meet the RPS.

Response

The Department intends that the plan holder have sufficient mechanical response resources to meet the RPS volume, including variety, type, and number to fully support the RPS scenario including protection of any environmentally sensitive areas that may be reasonably expected to be impacted during a spill of the RPS volume.

D. Protection of Environmentally Sensitive Areas and Areas of Public Concern (18 AAC 75.425(e)(3)(J))

Comment

One commenter felt that the proposed changes could become onerous to the plan holders by increasing the amount of planning required to protect environmentally sensitive areas and areas of public concern. The commenter requested that the regulation specifically refer to the Geographic Response Strategies (GRS) process as the preferred site-specific strategies.

Response

The Department disagrees that the proposed change would be onerous to the plan holders. Rather, by allowing reference to external documents, the regulation change would allow the efficient pooling of information between multiple plan holders.

Geographic Response Strategies (GRS) provide an acceptable method of meeting this requirement, but are not the exclusive method required by the Department. The Department does, however, strongly support the use of the GRS process to identify environmentally sensitive areas and options for their protection. The Department considers the GRS a useful tool which can be used to identify environmentally sensitive areas and potential tactics for their protection, both for areas potentially impacted by an RPS volume and for other spill response planning activities.

The proposed changes reference the “subarea contingency plan”, which is the common term used for the regional master oil and hazardous substance discharge prevention and contingency plans approved under AS 46.04.210. In order to fully identify which plan is referred to in the proposed regulations, an additional definition has been added to 18 AAC 75.990 confirming that “subarea contingency plan” means a regional master plan approved under AS 46.04.210.

8. Issues Relating to Response Planning Standards for Exploration & Production Facilities (18 AAC 75.434)

A. General

The development of a consistent and clear response planning standard (RPS) was a major emphasis of this phase of the project. The existing RPS volume was “scenario-driven” (based on a daily discharge rate times the number of days to control the well) and differed significantly from the fixed values used for other types of regulated facilities and vessels. The calculation of the number of days to control the well for the RPS calculation, and thus the RPS volume, was historically a contentious matter.

Additionally, the prevention credits portion of the regulations was out of date and required a major overhaul in order to accurately reflect the intent of the statutes (AS 46.04.030(m)).

B. Realistic Maximum Oil Discharge

Comment

Several commenters objected to the revised regulations, stating that the proposed response planning standard did not meet the statutory requirements of AS 46.04.030(k)(2) requiring planning for a realistic maximum oil discharge (RMOD). Specifically, they felt that the proposed response planning standard (RPS) was set at too low a timeframe (15 days) and did not accurately represent a worst-case discharge.

Response

The Department believes the commenters to have an incorrect understanding of the concept of realistic maximum oil discharge (RMOD) as it is defined in AS 46.04.030 and implemented in 18 AAC 75.434. RMOD is defined in AS 46.04.030(r)(3) as

> "… the maximum and most damaging oil discharge that the Department estimates could occur during the lifetime of the tank vessel, oil barge, facility, or pipeline based on the size, location, and capacity of the tank vessel, oil barge, facility, or pipeline; on the Department's knowledge and experience with the tank vessel, oil barge, facility, or pipeline or with similar tank vessels, oil barges, facilities, or pipelines; and on the Department's analysis of possible mishaps to the tank vessel or oil barge or at the facility or pipeline or to similar tank vessels or oil barges or at similar facilities or pipelines;"

The Department notes that there are three mitigating factors involved in the determination of RMOD:

- Size, location, and capacity,
- Knowledge and experience with the activity or similar activities, and
- Analysis of possible mishaps.

The Department notes that its knowledge and experience with exploration and production facilities shows that

- Crude oil spill data for North Slope exploration and production facilities (1986-1999) shows that 99% of spills were less than 25 barrels, with no spills greater than 1,000 barrels. The average spill was 3.8 barrels and the median was 7 gallons.
- Between 1977 and 2001, 4,965 wells were drilled or redrilled on the North Slope. During this timeframe there were 11 events where there was a loss or threatened loss of positive well control. None of the events resulted in any oil spilled.
- Historically, there have been 10 well blowouts in Alaska since 1958. Two of those blowouts resulted in oil spills. In both cases the wells bridged or were brought under control in less than 15 days.
- A study of historical North American well blowouts indicates that approximately half of all well blowouts bridge (collapse of well stopping the blowout) within one day and that a large majority of well blowouts bridge within one week.
- MMS analysis indicates that most historical blowouts have been of short duration. 20.7% ceased flowing in less than an hour, a cumulative of 57.5% in less than a day, and a cumulative of 83.9% in less than a week
- On the U.S. outer continental shelf, MMS and state regulatory agencies have recorded no well blowouts since 1985.
- Worldwide, among nations with drilling regulations similar to the U. S., there has been one well blowout resulting in an oil spill >1,000 gallons since 1985.

The Department also notes that federal oil spill analyses for the NPRA Northeast, NPRA Northwest, and Beaufort Sea generally place the probability of an oil well blowout or loss of control resulting in an oil spill greater than 1,000 barrels during the life of a particular well at effectively zero.

Given the historical well blowout events, historical trends, and analyses of possible well blowouts, the Department has determined that a 15 day planning standard is equivalent to RMOD.

C. Response Planning Standards (18 AAC 75.434(b) - (e))

Comment

One commenter stated that references to analog data and analyses do not add to the information gained and should be deleted for clarity. They also recommended the deletion of paragraph (d), stating that by the time the operator has data to confirm the flow rate exceeds 5,500 barrels per day, all exploration well operations will have been terminated.

Response

The Department has revised the wording of the proposed rulemaking to eliminate the reference to analog data and analysis in 18 AAC 75.434(b) and (e).

The Department has determined that 16,500 barrels within 3 days, plus 5,500 barrels/day for an additional 12 days, is an appropriate realistic maximum oil discharge for exploration wells, as discussed in the previous section. 18 AAC 75.434(b) provides a reasonable appropriate initial RPS for all exploration wells, based upon historical information concerning exploration wells in Alaska. 5,500 barrels/day is an appropriately conservative maximum flow rate that few wells can be expected to exceed.

The difficulty with establishing a case-by-case flow rate for exploration wells is that by their nature flow rate data cannot be predicted with any degree of certainty. Therefore the true flow rate for an exploration well cannot generally be determined until after the well has been drilled. The potential exists for exploration wells whose flow rate deviates significantly, higher or lower, from the default rate. But given that the flow rate is set very high all but a very few exceptional wells will have a significantly lower actual flow rate. 18 AAC 75.434(b) provides a mechanism for a plan holder to request a lower RPS for wells in well delineated and understood fields that can reasonably be expected to have a flow rate substantially lower than the default value.

If, after contingency plan approval, an exploration well is found to have an unusually large flow rate that exceeds 5,500 barrels/day, then 18 AAC 75.434(d) provides a mechanism for the Department to require an amendment to the contingency plan to reflect a higher RPS to compensate for the unusually high flow rates expected from future wells from the same formation. The Department will therefore retain paragraph (d) as a mechanism to increase the RPS flow rate for wells that deviate significantly from the anticipated high flow rate RMOD for exploration wells.

Comment

One commenter also had a concern that paragraph (e) sets an artificially high standard for a production facility. Various forms of production enhancing technology are applied to increase well producing rates. The first response to controlling the well is to terminate all artificial lift. Therefore, the commenter felt that the proper term in 18 AAC 75.434(e) (1) & (2) should be for the maximum <u>unassisted flowing</u> producing well.

Response

The Department has revised the response planning standard for production facilities to differentiate between wells that flow to the surface naturally and those that employ artificial lift and the difference in response requirements.

Comment

One commenter felt that AOGCC would be in a better position to hold the sensitive well flow information required by 18 AAC 75.434(g), should be the repository for such information.

Response

The Department disagrees. The Department has adequate measures in place to safeguard sensitive information, and has a need for the information required by 18 AAC 75.434(g).

Comment

One commenter felt that AOGCC should be the source of flow data used to develop the response planning standard and should be the authority to develop the response planning standard for exploration and production facilities.

Response

The Department disagrees. The Department has sole statutory obligation for review and approval of contingency plans, and therefore has a statutory mandate to review information considered necessary to determine the adequacy of a contingency plan. The Department would likely request AOGCC technical expertise in support of the Department's approval determination process, but final contingency plan review and approval rests with the Department.

D. Use of Nonmechanical Response Options to meet RPS

Comment

Several industry commenters requested a change in the regulations to allow nonmechanical response options to meet the response planning standard. Several non-industry commenters were concerned that the proposed changes would allow the use of nonmechanical response options to meet the response planning standard.

Response

The Department maintains that the RPS must be met using mechanical response technology. The existing regulations regarding contingency plan approval at 18 AAC 75.445(g)(1) clearly requires that the RPS must be met using mechanical recovery options. The Department maintains that this approval criteria is correct.

E. Voluntary Well Ignition (18 AAC 75.434(g))

Comment

One commenter requested that the proposed changes be removed; stating that the proposed changes would allow a response method for source control to reduce the response planning standard, setting an unfavorable precedent statewide that could reduce the overall level of oil spill preparedness and mechanical response capability.

Response

Voluntary well ignition is a method of reducing the amount of oil discharged to water or land, and is not therefore considered source control since it does not control the continuing discharge from a well.

9. Issues Relating to Contingency Plan Approval Requirements (18 AAC 75.445)

A. General

The changes to the contingency plan approval requirements are generally in support of changes made to contingency plan content requirements.

B. Response Strategies (18 AAC 75.445(d)(2))

Comment

One commenter felt that the Department should only rely on the Alaska Oil & Gas Conservation Commission (AOGCC) for determination of adequacy of the contingency plan, noting that AOGCC would be responsible for interfacing with the BLM and MMS where authorities overlap or coexist.

Response

The Department disagrees with this comment, and notes that the Department has sole statutory authority for contingency plan approval.

C. Realistic Maximum Response Operating Limitations (18 AAC 75.445(f)

Comment

One commenter requested that the approval criteria make clear that prevention measures are required at RMROL conditions.

Response

The Department believes that the proposed language correctly indicates our intent that the plan holder must propose specific alternative prevention and/or response measures to compensate for those periods of time when mechanical recovery may be ineffective due to environmental or safety reasons (18 AAC 75.425(E)(3)(D)). The Department will then review these measures and under 18 AAC 75.445(f) "may require the plan holder to take specific temporary prevention or response measures until environmental conditions improve to reduce the risk or magnitude of an oil discharge during periods when planned mechanical spill response methods are rendered ineffective by environmental limitations."

D. Response Equipment (18 AAC 75.445(g))

Comment

Several commenters requested that the proposed regulation (18 AAC 75.445(g)(5)) be revised to be more consistent with federal regulations regarding equipment efficiency ratings.

Response

The Department has revised the wording of the regulation to bring it in more in line with federal regulations in 33 CFR 154 and 40 CFR 112.

Comment

One commenter felt that the proposed regulation (18 AAC 75.445(g)(6)) did not fully consider the process of allowing on-water storage equipment to lighter to on-shore facilities.

Response

The Department has revised the wording, indicating that the capacity of the entire temporary storage system, including elements such as mini-barges, dracones, and on-shore storage, must be appropriate and adequate for the RPS.

E. Nonmechanical Response (18 AAC 75.445(h))

Comment

One commenter requested that the Department clarify the status of the in-situ burning (ISB) guidelines in the State of Alaska, and explain how the Department envisions those guidelines being used to support an in-situ burn response.

Response

The ISB guidelines and revisions have been adopted by the Department and the Alaska Regional Response Team as the decision making tool for On Scene Coordinators during emergency oil spill response. They have also been approved by the EPA and DEC Air Programs. The ISB guidelines will be used as proposed at the discretion of the On Scene Coordinators.

10. Issues Relating to Definitions (18 AAC 75.990)

A. General

The additions to the definitions section of the regulations are designed to clarify several items identified in the regulatory changes. The Department had added a definition of "response scenario" in the proposed regulations in order to further clarify the scenario requirements under 18 AAC 75.425(e)(1)(F). This definition was subsequently incorporated into the language of 18 AAC 75.425(e)(1)(F).

B. Average Annual Daily Production Volume

Comment

One commenter requested that the definition of "average annual daily production volume" be modified to read "… by an unassisted well flowing into the facility…" to recognize the fact that most petroleum production is enhanced with the continuous use of various artificial lift processes – gas lift, hydraulic lift, electric submersible pumping and rod pumping and that the first step in any containment process would be to terminate the artificial lift – turn off the gas or turn off the power.

Response

The Department has modified the response planning standard in 18 AAC 75.434(d)(2) for assisted lift wells to reflect the reduced potential spill volume and time period of spill.

C. Blowout Contingency Plan

Comment

One commenter objected to the phrase “will be employed” in the proposed definition, feeling that it implied a performance standard, not a planning standard.

Response

The Department notes that 18 AAC 75, Article 4 deals with planning standards, not performance standards. Performance standards for oil discharge removal are contained in statute (AS 46.04.020) and 18 AAC 75, Article 3.

D. Subarea Contingency Plan

The Department has added a definition of “subarea contingency plan” to indicate that a regional master plan developed under AS 4604.210 is the same document that the public and federal agencies generally identify as a subarea contingency plan, which is the federal regulatory designation for the same document, meeting the federal requirements of 40 CFR 300, Subpart C.

11. Implementation Schedule

These regulations will become effective for submittals of new contingency plans and plan renewals after the effective date of the regulations. Amendments of existing approved contingency plans will not be required to meet the new regulations until contingency plan renewal.

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APPENDIX 1 – RESPONSE TO COMMENTS ON INCORPORATING THE 1997 NORTH SLOPE PLANNING ASSUMPTIONS INTO 18 AAC 75.425(E)(1)(F)

The Alaska Oil & Gas Association (AOGA) and its member companies have reiterated their comment from the strawman draft regulations that the proposed contingency plan regulations do not provide adequate guidance for development of oil spill response scenarios, and propose that the inclusion of the 1997 North Slope Planning Assumptions into regulation would resolve this issue.

The Department has addressed what constitutes adequate guidance for the development of oil spill response scenarios in the main body of this document.

The Department agrees with AOGA that certain key assumptions developed in the 1997 North Slope Planning Assumptions document are germane to exploration and production facilities statewide and have therefore been incorporated into this rulemaking. However, the Department has determined that the incorporation of the 1997 North Slope Planning Assumptions in total into regulation has several outstanding problems which prevent their wholesale adoption:

- The 1997 North Slope Planning Assumptions were written as being general guidance only, specific to marine response for the North Star development. They were not, and are not, broadly applicable to exploration and production facilities in general throughout the state.
- The use and applicability of the 1997 North Slope Planning Assumptions is limited, based upon specific equipment resources and environmental factors.
- As proposed by AOGA, the proposed assumptions do not include revisions to the 1997 North Slope Planning Assumptions based upon the results of broken ice response exercises in 1999 and 2000.

As stated, the Department has incorporated several assumptions from the 1997 North Slope Planning Assumptions that were considered germane to all exploration and production facilities statewide into regulation, as delineated within the following table. The table also includes a brief comment column indicating why the Department is not adopting other specific assumptions.

Scenario planning assumptions are reviewed on a case by case basis due to the variation in facility type, size, and location. Many scenario assumptions are facility and location-specific, and the Department maintains its regulatory discretion regarding scenario assumptions in order to accommodate the specific facility and location.

Assumption Number	Assumption / Variable	1997 North Slope Planning Assumption For Spill Response Planning	ADEC Comment
1.	Blowout oil lost to evaporation from wells producing more than 5,500 bbl/day	• 20% applied to atomized well blowout where evaporation occurs before impact to land or water. • Adjusted RPS volume is not to decline below 5,500 bbl per day.	This assumption is specific to North Slope activities, North Star in particular, and is not broadly applicable to other facilities. Therefore this assumption is not adopted. This assumption is fully addressed in the changes to 18 AAC 75.434. It is unreasonable to assume a 20% immediate evaporation ratio for all crude oils in all well blowout scenarios. The 20% figure was specifically tailored to the high gas-to-oil ratio (GOR) and high flow rates of North Star. Typical wells have lower evaporation rates, lower GOR, and lower flow rates.
2.	Blowout discharge rate from existing production wells	• Annual average daily oil production for the maximum producing well (rounded to nearest thousand barrels) as reported by the Alaska Oil and Gas Conservation Commission (AOGCC).	This assumption is fully addressed in the changes to 18 AAC 75.434.
3.	Blowout discharge from new reservoirs	• 16,500 bbl for first 72 hours. • If rate is higher after initial production, use AOGCC data and submit c-plan amendment. ADEC condition of c-plan approval will specify timing of submission of production data.	This assumption is addressed in the changes to 18 AAC 75.434.
4.	Duration of planning period for a blowout	• 15 days based on consideration of historical duration of blowouts. • This does not mean response to a blowout ends after 15 days. C-plan will include ability to sustain response indefinitely.	These assumptions are addressed in the changes to 18 AAC 75.425(e)(1)(F)(iii) and 18 AAC 75.434.

Assumption Number	Assumption / Variable	1997 North Slope Planning Assumption For Spill Response Planning	ADEC Comment
5.	Out-of-region resources	• ADEC will consider use of limited out-of-region resources, including off-shift in-state specialists and specialists from other response organizations, to meet 72-hour adjusted RPS based on verifiable contracts and sharing agreements. • Out-of-region supplement beyond RPS demonstration is to be fully described. The c-plan will include mobilization plan, equipment list, and phone numbers. (Reference Prince William Sound Regional Citizens Advisory Council out-of-region report).	This assumption is addressed in the proposed changes to 18 AAC 75.425(e). 18 AAC 75.434(a) covers this assumption under departmental discretion. AS 46.04.030(k) supports this.
6.	Maximum wind speed	A. Open water: 20 knots (based on 95th percentile of wind speed for season).	This assumption is consistent with the proposed changes to 18 AAC 75.425(e)(1)(F)(xiii) which provides a basis, using National Weather Service data, for development of wind data inputs into scenario development.
		B. Broken ice: Historical mean wind speed for broken ice periods, i.e., 10 knots in break-up and 13 knots in freeze-up.	These assumption is consistent with a proposal for a scenario to meet 75.425(e)(1)(F) or to meet the RMROL conditions of 18 AAC 75.425(E)(3)(D).
7.	Directional persistence of wind	• First 24 hours: wind from southwest (based on historical data). • Next 48 hours: wind from northeast (based on historical data).	This assumption is addressed in the changes to 18 AAC 75.425(e)(1)(F)(xiii). This assumption is reasonably valid only for the first 72 hours, and doesn't adequately reflect historical or realistic weather data.
8.	Maximum wave height in mature fetch	A. Open water: 1.5 meters (based on historical data for North Star, NOAA atlas, and assumed 4-mile fetch for wave height). B. Broken ice: Wave height as predicted from ice dampening: less than or equal to 1 meter.	This assumption is addressed to the extent practicable in the changes to 18 AAC 75.425(e)(1)(F)(xiii). The specific assumption is highly location-specific, for North Star only. Assumptions of fetch and ice-dampening are not germane to all oil exploration and production operations.
9.	Ice coverage during broken ice periods	• Simulate ice movement and changes in ice percentage cover rather than constant percentage ice coverage.	This assumption is addressed in the proposed changes to 18 AAC 75.425(e)(1)(F)(xiii).

Assumption Number	Assumption / Variable	1997 North Slope Planning Assumption For Spill Response Planning	ADEC Comment
10.	Oil-to-water ratio of emulsion for storage purposes	• 60 parts oil to 40 parts water (i.e., oil volume x 1.67). • Based on Prince William Sound c-plan and S.L. Ross et al. (1998).	This assumption is a global change that will affect multiple regulated groups and will be addressed at a future time. Emulsion rates vary among different oils and weathering effects. The planning assumptions are for North Slope crude oil.
11.	Portion of oil entering open water	• S.L. Ross July 1997 blowout model's prediction of oil falling to water on site map plus oil falling to other surfaces in quantities greater than 0.5 gallon per square foot. • Existing on-site containment such as gravel berms can reduce the volume entering open water.	This assumption is addressed in the proposed changes to 18 AAC 75.425(e)(1)(F)(xiv).
12.	Slick size	A. Open water: • Fallout footprint based on S.L. Ross July 1997 blowout model using a blowout well with an open orifice. • Width of downwind zone of scattered oil = 0.25 x length. • Far field zone contains windrows of oil. B. Broken ice: • Oil slick takes form of windrows with ice less than 30% coverage; no windrows in ice coverage 30% or greater. Oil spreads less in ice. • Oil slick thickness and width as listed in Tables 6-2 and 6-3 of S.L. Ross et al. (1998).	This assumption is addressed in the proposed changes to 18 AAC 75.425(e)(1)(F)(xiv).
13.	On-water trajectory	• Vector sum of local current (speed and direction) and wind (direction and 3% of velocity).	This is a generally accepted guideline incorporated in most spill trajectory models and has not been contested.

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14.	Safety zone boundary (permissible exposure limit, PEL)	• 5 milligrams of oil particulate per cubic meter of air.	Safety zones are set based upon OSHA regulation, and need not be addressed into Department regulation. This assumption is therefore not adopted into regulation.
15.	Encounter rate	A. Open water: Use the Anvil model in lieu of the MEC model.	This assumption is specific to North Slope operations and not applicable to exploration & production facilities in general. This assumption is also covered under the 20% derating regulation 18 AAC 75.445(g). This is a global change.
		B. Broken ice: The skimmer system's oil encounter rate adjusted for ice concentrations and the containment effect of broken ice. Use the following formula: • [(oil thickness) x (the lesser of the width of collection boom swath or oil width) x (oil's speed)] x [1 – ice concentration] x [containment effect]. • Based on Appendix E in S.L. Ross et al. (1998) and on Attachment 3 of D. Dickins (1998). • The "containment effect" is 0 at 90% cover, 0.1 at 80% cover, 0.2 at 70% cover, 0.3 at 60% cover, 0.4 at 50% cover, 0.5 at 40% cover, 0.7 at 30% cover, 0.8 at 20% cover, and 0.9 at 10% cover.	This assumption does not agree with the results of the 1999 and 2000 broken ice exercises held on the North Slope. These assumptions are therefore not adopted into regulation.

Assumption Number	Assumption / Variable	1997 North Slope Planning Assumption For Spill Response Planning	ADEC Comment
16.	Derated oil recovery rate for skimmers	• 20% of pump's nameplate capacity based on ADEC guidelines, except for rates specified below. • Skimmer-specific rates: - LORI SCS-3: 80% x 271 bbl/hr = 217 bbl/hr - Foxtail: 30% x nameplate pump capacity (based on CISPRI test) - Vikoma 30K and MI-30: 10 bbl/hr	This assumption is specific to specific response equipment and is not applicable to all operations covered by 18 AAC 75, Article 4. This assumption is also covered under the 20% derating regulation at 18 AAC 75.445(g).
17.	Throughput efficiency (boom containment)	• Marine open water: 100%. • River system: minimum of 3 control sites with open-water marine backup.	These assumptions only cover marine open water and river systems and fail to include calm and protected water environments. Fast water containment (river systems) is highly dependent upon type of boom and its implementation. This assumption is addressed under the 20% derating regulation of 18 AAC 75.445(g). This is a global change.
18.	Advancing skimmer speed	• 0.7 kt.	This assumption is specific to North Slope response equipment and not applicable to exploration & production facilities in general. It is not specifically adopted into regulation at this time. This assumption is, however, addressed under the 20% derating regulation of 18 AAC 75.445(g), which takes into account a series of variables to determine recovery system efficiency. This is a global change.
19.	Barge storage capacity	• 95% of rated capacity.	This assumption is specific to North Slope and not applicable to exploration & production facilities in general. This assumption is not adopted into regulation. This is a global assumption that will be addressed later in regulation. The 1994 guidelines provide general guidance on this subject.

Assumption Number	Assumption / Variable	1997 North Slope Planning Assumption For Spill Response Planning	ADEC Comment
20.	Utilization time of recovery systems	• 10 hours in each 12-hour shift; 2 shifts per day. • Utilization time in first 72 hours = 60 hours minus time to deploy.	This assumption is addressed under the 20% derating regulation of 18 AAC 75.445(g). The proposed regulatory language mirrors federal regulations regarding recovery system efficiencies for federally required oil spill response plans.
21.	Mini-barge fill time (with weir skimmer and 2 decants)	• 1 hour (based on ACS field tests with DOP 250 pump and 249-bbl barge, Prince William Sound c-plan, and S.L. Ross et al. [1998]).	This assumption is specific to North Slope and Prince William Sound response equipment and average North Slope crude oil and not applicable to exploration & production facilities in general. This assumption is not adopted into regulation at this time. This assumption is a global change that will be considered later.
22.	Vessel and barge transit time	• 5 kt laden and unladen (based on USCG and ACS field tests).	This assumption is specific to North Slope response equipment and not applicable to exploration & production facilities in general. This assumption is not adopted into regulation.
23.	Mini-barge offload time	• 1.5 hours to hook, pump, and unhook (based on ACS field tests).	This assumption is specific to North Slope response equipment logistical concerns and ACS facilities and not applicable to exploration & production facilities in general. This assumption is not adopted into regulation.
24.	Decant from barges	• Large recovery and storage barges: 80% of free water. • Mini-barges: 60% of free water. • Based on Prince William Sound c-plan and ADEC guidelines.	This assumption is specific to particular response equipment and recovery techniques and is not universally applicable to exploration & production facilities in general. This assumption is not adopted into regulation.
25.	Delivery mixture from 249-bbl mini-barge coupled with weir skimmer	• 79 bbl oil, 53 bbl water-in-oil emulsion, and 104 bbl free water (2 decants required). • Based on Prince William Sound c-plan.	This assumption is specific to North Slope crude oil and 249 bbl mini-barge systems and is not universally true for all crude oils and all recovery barge systems. It is therefore not adopted for exploration and production facilities as part of this regulation package.