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State of Alaska
Department of Environmental Conservation
Division of Spill Prevention and Response
555 Cordova Street
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Fax: (907) 269-7687
Attention: Lydia Miner, Environmental Specialist
Jeff Mach, Oil and Gas Coordinator

RE: BP Exploration (Alaska) (BPXA) Greater Prudhoe Bay Unit, Oil Discharge Prevention and Contingency Plan, ADEC Plan Number 014-CP-5079.

To Whom It May Concern:

Thank you for this opportunity to comment on BPXA's proposed Oil Discharge Prevention and Contingency Plan for the Greater Prudhoe Bay Unit. Significant and specific concerns were raised by ADEC in the December 21, 2001 Request for Additional Information (RFAI). In our review of the plan, we have identified additional concerns, and noted where BPXA failed to supply the requested additional information.

I. GENERAL COMMENTS

A. RISKS TO THE FRAGILE ECOSYSTEM OF THE BEAUFORT SEA

The Arctic Ocean's Beaufort Sea is home to a multitude of fish and wildlife species. Polar bear, walrus, seal, several fish species and the endangered bowhead whale thrive in these waters. This unique natural resource is also a place dominated by ice, where temperatures can plummet to 60 below zero, where relatively stable land-fast ice and a mobile icepack interact violently in the ice shear zone, and where high winds and fog can make air or boat travel impossible much of the year. It is well documented that the unique natural treasures of the Arctic are sensitive to disturbances caused by industrial activities. As will be discussed in depth below, the Greater Prudhoe Bay oil spill plan does not do an adequate job of identifying sensitive areas and creating worst-case scenarios that set out realistic strategies to protect these important resources.

Further, in this remote part of America's Arctic, it is well accepted by the State of Alaska, federal agencies, the public, and the oil industry itself that oil companies currently lack the equipment to clean up any size of an oil spill in Arctic waters during much of the year. Given the combination of great local concern about offshore spills, a proven inability to respond to spills (through multiple failed spill drills), and the extreme environmental sensitivity of the area, the risks posed by the Greater Prudhoe Bay facility require an oil spill plan that reflects BPXA's absolute commitment to prevent and prepare for a large oil spill at the Greater Prudhoe Bay facility. As discussed below, this proposed plan fails to reflect these important goals, fails to respond adequately to ADEC's RFAI and fails to comply with statutory and regulatory requirements.

B. SIMULTANEOUS SPILLS

We are concerned that no contingency plans have been developed for simultaneous spills on the North Slope. We understand from conversations with ADEC staff that different spills are expected to required different mixes of training and machinery and therefore provoke little chance of needing the same personnel or equipment in two places at once. However, while this logic may have been appropriate when there were few development sites or wells, currently there are upwards of 19 active fields on Alaska's North Slope with hundreds of producing wells. Some of these fields have been in production for decades. As the infrastructure ages and the sheer number of fields expand, the chance of simultaneous spills increases. At Prudhoe Bay, for example, BPXA had 21 spills over 55 gallons in 2001, with six of those spills occurring within 24 hours of another spill. We believe aging fields, as well as the possibility of a terrorist attack on America's oil infrastructure, are ample reason to expand contingency plan requirements to include planning for simultaneous spills. Specifically, at Greater Prudhoe Bay there should be the capability to respond to multiple scenarios at the same time – meaning, of course, that the plan-holder should require equipment and personnel redundancy.

C. RELIANCE ON OUTDATED MATERIALS

We are extremely concerned with BPXA's reliance on the outdated Industry/Agency North Slope Oil Spill Response Assumptions contained in the "Guidance for Preparing Marine Response Scenarios" and the Alaska Clean Seas (ACS) Technical Manual. Significantly, the use of the Guidance document is highly inappropriate as it compromises ADEC's regulatory authority, in violation of AS 46.04.030(h). We understand that ADEC completed a review of the Guidance and Manual, and noting that they contain numerous false assumptions, issued a report containing recommended changes. However, BPXA's application for renewal repeatedly relies on the Guidance and ACS Technical Manual rather than providing updated information in the application. This is especially troubling as BPXA continues to revert to the "15 day" timeframe for well control, the use of production well flow data instead of basing volume calculations on unrestricted flows, and the use of unrealistic wind assumptions and encounter rates. The failure to use an appropriate encounter rate model alone makes it impossible to assess whether the adequate number and type of skimming systems are proposed, and it is impossible to assess if the response equipment is best available technology as required under AS 46.04.030(e). The incorrect assumptions in the Guidance should be withdrawn and the plan-holder should be required to include the appropriate up-to-date information and the best available technology in the application, in compliance with the regulations and with the understanding that BPXA cannot phase its incorporation of best available technology.

II. TRANSPORT PROCEDURES (Section 1.5.1)

Here, and throughout the plan, BPXA assumes that transport "[m]obilization times are general estimates based on ideal conditions." This optimistic calculation violates ADEC regulations. Mobilization times should reflect realistic "seasonal environmental conditions," not "ideal" conditions. 18 AAC 75.445(d)(2). This incorrect use of ideal conditions creates a multitude of problems, including an underestimated response planning standard volume.

III. WELL CONTROL/RELIEF WELL PLAN (Section 1.6.3)

The daily volume for a blowout must reflect the actual oil to gas ratio and the well pressure. The Greater Prudhoe Bay plan bases a production blowout on the daily production volume, not on what an uncontrolled daily volume would be given that BPXA re-injects gas to increase the reservoir pressure, and then must choke that pressure back. As a result, the amount of oil that would blow from Greater Prudhoe Bay's highest producing well could be far greater than a controlled daily volume (also, there is no indication in the plan that BPXA even used the highest producing well data). BPXA should not be allowed to rely on the Guidance document in lieu of ADEC regulations to base its daily maximum volume on average daily production volumes. *See, for example*, 18 AAC 75.430(a); AS 18 AAC 75.434(b).

In response to ADEC's request for relief well timeframes, BPXA shortened to 15 days the response time for well capping, shortened the well capping after ignition to 26 days, used the 15 days for volume calculation, and then acknowledged that a relief well would take 39-90 days. As mentioned above, BPXA reliance on the outdated Guidance as justification for the 15-day assumption is unacceptable and unsupported. BPXA should not be allowed to arbitrarily decrease the well capping timeframe from 18 to 15 days, or decrease the capping operation after ignition from 30 to 26 days.

Additionally, the response timeframe should be based on realistic mobilization and well control timeframes, not on either "ideal" mobilization or incorrect information. No consideration is given for weather conditions; particularly fog, winds and other hazards may impede well control timing and oil spill response. For a timeframe to be considered realistic, it must include seasonal environmental conditions that might reasonably be expected to preclude emergency operations from regaining control of well pressure, as required by 18 AAC 75.445(d)(2); 18 AAC 75.445(f).

Further, the response planning standard volume *must* be based on the relief well timing in seasonal environmental conditions, not the well capping timing. Using the information contained in the plan, a 90-day flow – not a 15-day flow – should determine the RPS volume. *See* AS 46.04.030(r)(3) (definition of realistic maximum oil discharge as the "maximum and most damaging oil discharge"); 18 AAC 75.434(b) (response planning standard volume to be based on "each day beyond 72 hours necessary to stop the discharge."). ADEC has not approved well capping as best available technology, and ADEC has never certified well capping nor set out any guidelines to govern the use of this proposed technology.

There are also no details provided about the contracts with WELLCALL, WELLCALL does not appear to be registered as required under 18 AAC 75.510(a), and BPXA fails to state whether there is an exclusive agreement for WELLCALL to respond to the Greater Prudhoe Bay wells. What are the estimated mobilization timeframes, for example, if there are concurrent blowout scenarios with two (or more) WELLCALL clients? Also, along with listing well capping equipment, BPXA must detail precisely the arctic-specific well capping training its employees undergo. Finally, for well capping to be a reasonable alternative, BPXA must first demonstrate that each wellhead is reachable (and thus suited for capping) at the Greater Prudhoe Bay facility.

IV. RESPONSE PLANNING STANDARDS (Section 1.6.13)

As discussed above, it is a violation of ADEC regulations to allow BPXA to rely on the Guidance document to limit spill volume calculations to a 15-day flow, fail to use an unrestricted flow rate to calculate the daily discharge rate, and fail to establish that BPXA actually picked the wells with the highest flow rates for each drill site location.

The response planning standard volume in the 1999 plan was based on a flow rate of 12,000 barrels/day. Why did the flow rate change so drastically between 1999 and 2002? It is obviously expected that production rates drop over time, but the drop from 12,000 barrels/day to 3,000 barrels/day is drastic, unexplained and unsupported by data. BPXA must use the default rate of 5,500 barrels/day unless and until another rate is warranted based on the requirements in the regulations. Any blowout model that use these flawed assumptions will necessarily be incorrectly based on an unrealistically low volume.

With respect to the sales oil pipeline, BPXA asserts that the smaller RPS volume reflects a lower produced oil throughput since the last plan approval and "the capacity of the low pressure sensors to automatically trigger emergency shut down." Given BPXA's leak detection problems and safety valve system performance problems, this unsupported assertion is extremely problematic. BPXA should not limit its volume based on unsupported and untested assertions that low pressure sensors will decrease shut-down time. Additionally, BPXA asserts that it will submit a new pipeline spill response scenario following plan approval. Any approval of this plan would therefore constitutes illegal phasing, and is contrary to the statutory requirement that contingency plans "must provide for use … of the best available technology that was available at the time the contingency plan was submitted or renewed." AS 46.04.030(e).

V. SCENARIOS (Section 1.6.14)

A. GENERAL COMMENTS ON SCENARIOS

The scenarios do not model response planning standard volumes as defined by statute and regulations, and BPXA consistently underestimates (and thus fails to plan for) RPS volumes. The result is a gaping hole in identifying and protecting sensitive areas, and planning for response personnel and equipment. Significantly, BPXA has consistently refused to provide a master equipment list, meaning that the only guaranteed equipment is what is listed in the flawed scenarios. This is entirely unacceptable.

We also question the validity of the wind conditions established for the scenarios. Under the flawed and illegal Guidance document, the same wind pattern is depicted for each scenario – "Day 1: From the SW, Day 2 and beyond: From the NE". This static pattern fails to take into consideration seasonal differences, and is unsupported by data.[1] The spray pattern depicted on many of the scenario maps supposedly reflects these wind conditions – the spray following fairly narrow plumes in the SW and NE directions with no intermediate arc. However, such a spray pattern is unrealistic, and undermines the purposes of the scenarios to identify possible spill situations. According to Prudhoe Bay wind data reported in the Northstar ODPCP (3.2.1), wind blows from the east to northeast for about 60% of the time and from the west and southwest for about 28% of the time. If the wind conditions in the scenarios corresponded with these data, we would expect much wider plumes in both the E/NE and W/SW. In addition, as the wind changed direction, we would expect some intermediate arcing of oil. This use of flawed wind data artificially reduces the potentially impacted areas, reduces the oil that enters the Beaufort Sea, and limits the projected need for shoreline protection and other efforts that could safeguard environmentally sensitive areas.

In its letter responding to the RFAI, BPXA states that River sites KUP-3, KUP-4, and KUP-5 have pre-deployed boom, and asserts that it deploys this boom annually at the beginning of the open water season. This assertion must be in the plan itself, along with dates by which the boom will be in place. Otherwise, this assertion is not enforceable and should not be considered as part of the spill plan.

Additionally, as not all wells that could spill oil into water (including rivers, lakes and the Beaufort Sea) are covered by the seasonal drilling restrictions, the plan *must* provide for water-based scenarios.

Finally, we note that there is no scenario for the Greater Prudhoe Bay sales oil pipeline. This is completely unacceptable. BPXA cannot at once argue that the scenarios drive the response equipment requirements while at the same time leaving out the scenario with the biggest potential volume discharge into a river. At revised page 1-33, BPXA asserts that from "Flow Station #1, 170,000 bopd is shipped in a 34-inch transmission pipeline over the Little Put River." BPXA uses the sale line for its RPS volume, but then fails to provide a scenario for this volume. BPXA *must* provide a scenario for a pipeline spill into the Little Put at break-up. To defer this addition for a later date is unacceptable phasing.

B. SCENARIO 1: PN-2 BLOWOUT IN WINTER

As discussed above, the wind assumptions are flawed and the response planning standard volume should be based on 5,500 barrels/day for as many days as it takes to drill a relief well.

There is no logical rationale provided for the deletion of the ice road tactic (Tactic C-10). Tactic C-10 provides for the construction of an ice road around the blowout, "using an ice road ring." Why is BPXA removing a tactic that could improve oil spill containment, speed up the movement of equipment to the location and provide a working surface for response equipment operations?

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[1] See, for example, the seasonal differences and trends recorded by Minerals Management Service at: http://www.resdat.com/mms/metstation_graphs.cfm?quarter_id=1&graph_type_id=9, visited 2-16-02.

C. SCENARIO 5: PIPELINE RUPTURE OVER KUPARUK RIVER TO OPEN WATER

To comply with statutory requirements, this scenario should occur at the time of the highest yearly flow of the Kuparuk in broken ice. Using the highest flow rates, BPXA must create a scenario that reflects how sensitive areas will be protected.

D. SCENARIO 6 & SCENARIO A: NORTHWEST EILEEN EXPLORATION WELL BLOWOUT DURING WINTER / SAK RIVER #1 BLOWOUT DURING WINTER

These scenarios use the flawed 15-day assumption and the unrealistic wind patterns as discussed above. As well capping is not even a viable option during exploration phases, BPXA must use relief well timing to establish the planning standard volume. Additionally, a scenario should occur late in the season to reflect how BPXA would remedy a spill in the most challenging conditions possible – for example, a blowout at Sak River #1 late in the drill season with oil falling on Beaufort Sea that was inaccessible by ice roads.

VI. PREVENTION, INSPECTION, AND MAINTENCE PROGRAMS (Section 2.1)

BPXA fails to respond to ADEC's request for information regarding maintenance programs in the field. BPXA must comply with the requirements of 18 AAC 75.425(e)(2)(A), and provide a description and schedule of regular pollution prevention, inspection, and maintenance programs in place at the facility.

VII. GENERAL PREVENTION – TRAINING PROGRAMS (Section 2.1.1)

Again, as above, merely re-stating a reporting standard is not enough. Providing a document like the 12-14-01 reference document is not adequate, unless it becomes part of the plan and is distributed for public review.

VIII. BLOWOUT CONTROL / SEASONAL DRILLING RESTRICTIONS (Section 2.1.7)

Oil spills during open water, fall freeze up and spring breakup are likely to have significant adverse impacts on a variety of marine mammals, marine and anadromous fish, coastal birds, and other wildlife that depend on Alaska's North Slope coastal waters and shorelines. Migratory birds use these areas during their migrations, and they are extremely vulnerable during the periods that coincide with times when oil spill cleanup is impossible due to lack of access and ineffective equipment. In addition, sheet flow during breakup would spread any spill across wetlands, rivers, or stream substantially further than any other time of the year. For these reasons, seasonal drilling restrictions are essential.

The June 1 date proposed by BPXA is inadequate to prevent a blowout from reaching open water and/or broken ice. The 2000 North Slope broken ice tests near Northstar demonstrated that marine equipment could not be fully mobilized until early July. As cited in ADEC's RFAI, weather information indicates that ice road integrity is lost in early to mid May, which effectively stops response operations being conducted on the ice. This loss of offshore access together with time requirements for drilling a relief well confirms that an April 12 cut-off date for drilling operations is required to avoid the 72-hour open water response planning standard.

At the same time, ADEC must reserve the regulatory flexibility to shorten the drilling season to accommodate unseasonable weather conditions. ADEC must err on the side of protecting the environment, not on the side of increasing industry revenue.

BPXA's proposed seasonal drilling restrictions in the spill plan do not include all production pads and drill sites adjacent to the Beaufort Sea or major rivers which could result in blowouts to open water and/or broken ice. If seasonal drilling prohibitions are to ensure elimination of blowout potential to open water and broken ice, then all production facilities next to open water bodies need to be incorporated, including those adjacent to lakes. We urge ADEC to require seasonal drilling restrictions for *all* Greater Prudhoe Bay wells that could blowout into water bodies, and specifically into the Beaufort Sea and Kuparuk, Sagavanirtok and Putuligayuk rivers.

In the event BPXA proposes resumption of drilling during the open water and/or broken ice seasons, or extending drilling past when an entirely on-ice cleanup is possible, ADEC should require three response barges with tug support and establish the date based upon the onset of ice concentrations less than 10% (as established in the 2001 Joint Agency Report).

Finally, we understand that BPXA has declined to change the seasonal drilling restriction date to the safer and more reasonable date in April, citing the voluntary nature of the restrictions as well as implying an economic impact on their business. However, as the spill drills near Northstar showed, BPXA was not capable of meeting mandatory ADEC spill cleanup requirements. Therefore, until such time as BPXA can prove capable of sufficiently cleaning up a spill in open water and/or broken ice conditions, seasonal drilling restrictions are a *mandatory* requirement, and ADEC must enforce the use of dates that allow for an entirely on-ice cleanup. BPXA's proposal to address response planning standard compliance and the seasonal drilling restriction issues at a later date constitutes illegal and unsafe phasing.

IX. LEAK DETECTION (Section 2.1.8)

ADEC should not approve this spill plan unless *the person is in compliance with the plan.* AS 46.04.030(b). In BPXA's case, ADEC has confirmed, and BPXA has acknowledged that the crude oil transmission lines do not comply with the leak detection standards for pipelines. *See* 18 AAC 75.055(a)(1);18 AAC 75.425(e)(4)(A)(iv). Leak detection standards have been in place since 1992 – ADEC should not allow any further delay in installing, testing and ensuring that BPXA's transmission lines meet regulatory standards. Further AS 46.04.030(e) requires that the applicant use the best available technology *at the time the plan was renewed*. The technology exists (for example, the use of turbine meters in conjunction with other technology was determined to be best available technology at facilities like Lisburne), yet BPXA has failed to implement such technology at Prudhoe Bay because of the cost of additional meters (estimated at around $10 million). Yet cost is not necessarily an excuse to fail to implement best available technology – especially in the largest oil field in Alaska.

BPXA states that it "believes the summary reports discussing piping inspection, maintenance and repair are better represented in the report, Commitment to Corrosion Monitoring, submitted to ADEC annually." Once again, BPXA tries to address issues required by the spill plan outside the context of the plan, where the obligation is not legally enforceable – just like the placement of booms and the training programs discussed in above sections. BPXA also attempts to convert a performance standard into a mere reporting standard. This material should be addressed in the plan, so that it is legally binding for compliance and enforcement.

BPXA has acknowledged that a 1% standard must be met, but that it has repeatedly failed to meet this standard. The February 3, 2002 Anchorage Daily News reported that ADEC and BPXA plan to bring leak detection in compliance by the end of 2002. Why does it take so long? Leak detection has been required for 10 years, and BPXA is grossly out of compliance with the statute and regulations.

X. SECONDARY CONTAINMENT AREAS (Section 2.1.10)

ADEC should be required to complete a full best available technology analysis on secondary containment, justifying that any existing waiver is appropriate and that new technology is not available to address the previous concerns, or ADEC must require BPXA to install the containment.

As most of the waivers granted for secondary containment were granted prior to the April 1997 best available technology regulations, these waivers should have been re-evaluated in the 1999 renewal and a best available technology analysis should have been completed. Especially in light of the recent *Lakosh v. ADEC* Alaska Supreme Court decision, the waivers should be now be revoked and a full best available technology analysis should be completed. *See Lakosh v. ADEC*, Opinion #5531, Feb. 1, 2002.

XI. DISCHARGE DETECTION (Section 2.5)

ADEC rightly asks BPXA to specify the threshold for shutting in the pipeline versus visually confirming a leak, and BPXA completely fails to respond to this clear question. If BPXA cannot answer the question, it goes to follow that neither can its employees. This threshold question obviously has an important impact on potential spill volume and associated environmental impacts.

XII. RESPONSE EQUIPMENT (Section 3.6)

A master list of personnel, equipment and materials necessary for containment and recovery must be included, including the location, inventory and ownership of the equipment. 18 AAC 75.425(e)(3)(F). Other than a list of well capping equipment, the only equipment and materials listed are scenario-based. It is vital to list all of the equipment available. This ensures that all contingencies are covered, not just the ones depicted in the scenarios, and allows an overview necessary for contending with multiple scenarios at the same time. When ADEC asked BPXA to commit in the spill plan to keeping the equipment listed in the ACS Mater Equipment List on the North Slope, BPXA declined that request, and pointed to its scenarios for all needed equipment. This response is entirely unacceptable.

Is BPXA essentially saying that if the plan fails to cover a particular scenario, BPXA is not required to have the equipment ready to respond? The plan only has a handful of scenarios. Surely there are other examples of spills – such as the sales oil line or an oil tank rupture into a river during broken ice – that BPXA must plan for. Allowing BPXA to only commit to equipment in the scenarios makes absolutely no sense, and it is extremely dangerous.

In addition, we understand that the required number of barges stationed off of the North Slope has decreased from five to one (at Northstar). We recognize that the North Slope broken ice tests conducted in 2000 show that barges have severely reduced recovery efficiency in broken ice. It was concluded in the Joint Agency Report that the realistic maximum operating limitation for broken ice is 10% concentration without ice management, but perhaps as high as 30% with ice management. The report did not, however, conclude the response barges were completely ineffective, but that for planning purposes low recovery rates must be used. Therefore, the three barge systems should be retained with tugs for ice management to increase recovery.

Because BPXA provides no scenario where a barge/tug system is used, BPXA has no commitment to maintain response barges and tugs. ACS has large capacity skimmers, ocean boom and even work boats during broken ice that cannot be deployed without access to large barges. Since this response equipment is also not included in the scenarios, BPXA has no commitment for maintaining this equipment either.

As previously discussed, the seasonal drilling date of June 1 is not sufficiently conservative to ensure a blowout to broken ice will not be possible. Additionally, the pads and drill sites located nearby the Beaufort Sea coastline and major rivers are not currently subject to drilling restrictions.

We urge ADEC as a condition of approval to require BPXA to provide a master list of equipment, personnel and materials, and maintain the three ice-breaking response barges with tug support for transportation, logistical support and ice management.

XIII. NONMECHANICAL RESPONSE INFORMATION (Section 3.7)

"BPXA does not anticipate, but does not preclude, the use of dispersants for spill response in the Beaufort Sea. Dispersant equipment is not maintained on the North Slope." That concludes the totality of the discussion of dispersants. This is entirely inadequate. If used, how much dispersant would be used? What is the possible outcome of using dispersants? What are the possible effects on the environment? What training have the response personnel received regarding dispersants? A more complete discussion is necessary if dispersants are to be considered an option, however unlikely.

XIV. BEST AVAILABLE TECHNOLOGY (Section 4)

ADEC must "insist on the use of best available technology in addition to demanding compliance with performance standards." *Lakosh v. ADEC*, Opinion #5531, Feb. 1, 2002. In the Greater Prudhoe Bay plan, neither best available technology (as ADEC has yet to define what this means as required by the court) nor performance standards are met. From leak detection to offshore response, BPXA cannot meet the "best available technology" standard. For example, BPXA states in the January 2002 revision that "containment and recovery systems deployed by ACS in broken ice have been predicated on the use of large booms to sweep oil to skimmers. The Ro-Boom is an excellent choice for this purpose. It is considered to be BAT." BPXA largely ignores results from the oil spill drills that revealed that the booms and skimmers failed to work in open water and broken ice conditions. The information learned in those drills must be included here to indicate a re-working of assumptions and an effort to improve mechanical recovery. There are existing mechanical recovery possibilities that BPXA has not tried (such as shallow water spill response vessels).

BPXA did submit best available technology analyses for response equipment. As submitted, BPXA's BAT analyzes particular types of mechanical containment and recovery components but not as functional systems. Significantly, the BAT analysis does not include ice-breaking response barges, tugs or work boats that are necessary to assemble a functional recovery system. Moreover, the BAT analysis is meaningless unless BPXA is required to maintain response barges and tugs, in order to deploy large skimmers and boom that require large platforms. BPXA's proposed BAT analysis appears to take credit for equipment that it will not commit to maintain in ACS's inventory.

As recommended above, BPXA should be required to maintain the three ice-breaking response barges and tugs. ADEC should require BPXA to revise the BAT analysis to include barges, tugs and work boats. Additionally, it should be a requirement of approval that the BAT review analyze complete recovery systems using realistic test results.

As such, ADEC should continue to require oil spill drills for all facilities that could spill hydrocarbons into waters, and support the public attendance of such drills. Further, ADEC must also require prevention measures to be best available technology, including requiring corrosion control and smart pigging. It is unacceptable for ADEC to continue to approve spill plans that are not only not BAT, but are shown not to meet performance or prevention standards.

Finally, given the unique arctic environment, we believe that BPXA should use equipment built for the climate and conditions of the North Slope and Beaufort Sea. This equipment should be designed to operate in ice-infested conditions, shallow waters, sub zero temperatures and arctic weather. In addition, responders – including WELLCALL if well capping were to become best available technology – must be trained in arctic conditions, and not simply imported from other areas of the country where response training is unrelated to the type of conditions present in the arctic. Spill field drills should be a required condition of the spill plan as they are extremely important for training personnel in the actual equipment, to discover flaws in assumptions, and to familiarize personnel with the site-specific geography for responses covered by each spill plan.

XV. THE UNADDRESSED NEED TO FIX PAST & ON-GOING PROBLEMS

First, BPXA was fined for non-compliance in a tank audit. What system or systems have been put into place to ensure that inspections are completed and documented, and that personnel have adequate qualifications to complete inspections and repairs?

Second, there is a serious compliance issue regarding safety valve system performance in Prudhoe Bay. BPXA must address how it will remedy these serious problems to meet the best available technology standard. *See* Petroleum New Alaska News Bulletin, Vol. 8, No. 19, February 14, 2002.

Third, there were a series of large spills at Prudhoe in 2001. It is not clear what – if anything – BPXA has done in this spill plan to prevent similar spills in the future, as required by 18AAC 75.425(e)(2)(B).

CONCLUSION

We understand that the oil spill plan review process has come under fire from the oil industry. The industry claims, among other things, that timeframes for plan reviews are too long and that agency demands are unreasonable. The industry is wrong on both fronts when it comes to the Greater Prudhoe Bay plan. First, we received the draft plan in late October 2001, then ADEC gave its Request for Additional Information to BPXA on December 21, 2001, and BPXA responded to ADEC on January 30, 2002, which the public received on February 1. Then BPXA submitted additional information that had been left out of its response to the RFAI. That information was distributed to the public on February 4, February 6 and February 7, thus requiring an extension of the public comment period to comply with ADEC regulations. Even with the BPXA-created delays, in total the plan will have taken approximately 120 days to review – a length well under historical timeframes for plan approval. Second, as we discussed above, there are significant problems with the Greater Prudhoe Bay plan. This proposed plan is dangerously based on unrealistic assumptions, and it is contrary to statutes and regulations governing spill plan requirements. As concerned members of the public, we urge the ADEC to require BPXA to address specific, significant issues like seasonal drilling, leak detection, scenarios that reflect actual North Slope conditions, complete equipment lists, best available technology, and realistic mobilization timeframes for response and spill volumes.

We thank ADEC for recognizing the importance of give and take between the agency, the industry and the public. Large oil spills impact all Alaskans, and the public must be allowed to continue legitimate participation in spill plan review.

Sincerely,

Jenna App

On Behalf of

Sara Callaghan Chapell
Sierra Club – Alaska Field Office

Pamela A. Miller
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