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Via Electronic Filing
April 1, 2011

Anne-Marie Erickson
Secretary of the Board
National Energy Board
444 Seventh Avenue S.W.
Calgary, AB T2P 0X8

Dear Ms. Erickson:

Re: Arctic Offshore Drilling Review, NEB File: OF-EP-Gen-AODR 01
Additional Response to CFI #1 and #2

On behalf of WWF-Canada, please find attached our additional response to the Board's Calls for Information #1 and #2 in the Arctic Offshore Drilling Review.

Yours sincerely,

Will Amos
Counsel, representing WWF-Canada

Arctic Offshore Drilling Review
Additional Response to CFI #1 and #2
WWF-Canada, April 1, 2011

Contents

SUBMISSION COVER PAGE

This submission adds to WWF-Canada's submission dated November 29, 2010 (November submission),[1] and for ease of reference the same layout and headings are used to the extent possible. The following table attempts to help identify which issues in the Board's Scope of the Review[2] each section in this submission primarily relates to, and which questions in the Board's two Calls for Information (CFI #1 and #2)[3] each section primarily responds to.

Section in this submission	*Primary issues in the scope of the Review that each Section relates to*	*Primary CFI #1 and #2 questions that each Section relates to*
2. CHANCES OF A BLOWOUT	#1 (potential hazards & risks) #2 (preventing & mitigating risks) #4 (effectiveness of well control) #10 (lessons learned)	1.1.2 (management system re: hazard & risk identification) 1.1.3 (safety culture) 1.4.1 (well control) 1.5.1(a),(b) (hazards leading to major blowout) 1.10.1 (lessons learned) 2.2.1(a),(b) (hazard identification) 2.2.2(a),(c) (effectiveness of equipment, BOPs) 2.2.4 (human factors and risk) 2.3.2 (pore pressure prediction)
3. SAME-WELL INTERVENTION TECHNIQUES	#2 (preventing & mitigating risks) #4 (effectiveness of well control) #5 (responding to accidents, spills, & malfunctions) #6 (regaining well control) #10 (lessons learned)	1.5.1(a),(b) (hazards leading to major blowout), 1.5.1(m) (length of time to bring under control) 1.6.2 (regaining control) 1.10.1 (lessons learned) 2.2.2(a),(c) (effectiveness of equipment, BOPs)

[1] Our November submission is available at https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=654255&objAction=browse.

[2] The Board issued the scope of the review on Sept 20, 2010, available as Appendix A at https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=634807&objAction=browse.

[3] The Board issued CFI #1 on Oct 1, 2010, available at https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=639658&objAction=browse. The Board issued CFI #2 on Nov 23, 2010, available at https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=653642&objAction=browse.

4. SAME-SEASON RELIEF WELL (SSRW) CAPABILITY	#2 (preventing & mitigating risks) #4 (effectiveness of well control) #5 (responding to accidents, spills, & malfunctions) #6 (regaining well control) #10 (lessons learned)	1.5.1(a),(b) (hazards leading to major blowout) 1.6.1 (relief wells), 1.6.2 (regaining control) 1.10.1 (lessons learned)
5. RESPONDING TO SPILLED OIL	#2 (preventing & mitigating risks) #5 (responding to accidents, spills, & malfunctions) #7 (spill containment and clean-up) #10 (lessons learned)	1.5.1(d)-(g),(k) (response capabilities), 1.5.1(h),(j) (differences to Gulf), 1.5.1(o) (oil recovery), 1.5.1(p) (time to clean-up) 1.10.1 (lessons learned) 2.7.1 (effectiveness of available spill containment and clean up options)
6. SOCIAL-ECOLOGICAL IMPACTS OF SPILLED OIL	#3 (state of knowledge of the Arctic offshore) #9 (state of knowledge of spill impacts) #10 (lessons learned)	1.5.1(c) (ecosystem components put at risk), 1.5.1(h) (differences to Gulf), 1.5.1(o) (impact on environment) 1.9.1 (knowledge of long term impacts) 1.10.1 (lessons learned) 2.3.1 (unique Arctic environment)
7. RISK FRAMEWORK FOR ARCTIC OFFSHORE ACTIVITIES	#1 (potential hazards & risks) #4 (effectiveness of well control) #6 (regaining well control) #7 (spill containment and clean-up)	1.1.2 (management system re: hazard & risk identification) 1.4.1 (well control) 1.5.1(a),(b) (hazards leading to major blowout) 1.6.1 (relief wells), 1.6.2 (regaining control) 2.2.1(a),(b) (hazard identification)
8. FINANCIAL RESPONSIBILITY AND LIABILITY	#2 (preventing & mitigating risks) #8 (financing clean up, restoration, compensation) #10 (lessons learned) #11 (filing requirements)	1.8.1 (financial liability) 1.8.2 (financial responsibility) 1.10.1 (lessons learned)

This submission was prepared by Will Amos, Dave Burkhart, Keith Ferguson and Rob Powell. It was reviewed by Bill Adams, Greg Bourne, Renee Dopplick, Layla Hughes, Martin von Mirbach and anonymous reviewers.

1 INTRODUCTION AND OVERVIEW OF PRELIMINARY CONCLUSIONS

In response to the Board's Calls for Information (CFI) #1 and #2, this submission adds additional information to our November submission, and the two should be read together. To make that easier, we have followed the same format here as in that previous submission, using the same headings and ordering to the extent possible. One change, however, is that we start each section with a discussion of lessons learned from the now-available Commission reports that investigated the Macondo blowout in the Gulf of Mexico in 2010 (the 'National Commission'), and the Montara blowout off the Northwest coast of Australia in 2009 (the 'Montara Commission'). We end each section with some preliminary conclusions, termed 'preliminary' because we have not yet seen any substantive submissions from industry, government or other participants in this Review.

Overall, WWF-Canada believes there are some areas in offshore Arctic waters in which oil and gas exploration should not occur because of environmental sensitivity. We believe a comprehensive process of marine spatial planning should be used to identify such areas. After a sufficient set of such areas has been identified (i.e. 'conservation first'), in areas that are not designated off limits, WWF-Canada believes oil and gas exploration should only occur if: (1) risks (including risks to off-limit areas) can be reduced to 'acceptable' or 'tolerable' levels and, if so, then (2) all risks are reduced to as low as reasonably practicable, and (3) cumulative impacts can be kept below appropriate thresholds. Given the nature of the Board's Review and of its questions in CFI #1 and #2, this and our November submissions focus on items (1) and (2).

Based upon what we have seen to date, WWF-Canada's preliminary conclusions are the following:

1. As explained in section 2: Past industry estimations of the chances of a blowout appear overly optimistic, especially in light of recent events. Given the additional risks and uncertainties in the Arctic combined with the very serious consequences, the potential for a blowout must be taken seriously. In the Arctic, a blowout that continues throughout the off-season, and thus lasts a year or more, should simply not be acceptable.

2. As explained in sections 3, 4 and 5: There are numerous scenarios in which same-well interventions to bring a blowout under control would not be available, effective or timely, and thus same-season relief wells continue to be a necessary option for blowout response. Additional rams on the BOP stack or other similar well control improvements are not equivalent to same-season relief wells. The SSRW capability requirement should therefore remain in place for all offshore Arctic drilling, and where it cannot be assured, drilling should not be approved.

3. As explained in sections 3 and 4: There is a need for appropriate end-of-season cut-off dates to allow sufficient time for not only SSRW capability, but also to allow time to attempt same-well intervention techniques.

The above two requirements are aimed at limiting blowouts to being at most one season long. However, as with the Macondo and Montara blowouts, within-season blowouts of a few months duration can still be devastating, leading to our next preliminary conclusions.

4. As explained in section 3: Same-well containment and control methods must be improved and demonstrated for Arctic offshore use to reduce the probability of a long-duration blowout and to reduce the probability of all the oil escaping during a blowout.

5. As explained in section 5: Industry claims about the effectiveness of oil spill cleanup in Arctic waters come from small-scale controlled experiments that do not extrapolate to real world conditions. Rather, only a tiny fraction of oil can be expected to be recovered from a blowout. Any assessment of the potential consequences of a spill or blowout should take this into account.

6. As explained in section 5: Improved cleanup of spilled oil must be demonstrated under real-world conditions in Arctic waters to be able to remove a significant percentage of the escaped oil before cleanup can be relied upon as a meaningful mitigation measure.

In order to monitor the impacts of offshore activities and plan for potential incidents, it will be necessary to better understand the baseline environmental conditions and potential impacts from spilled oil prior to exploration.

7. As explained in section 6: A significant oil spill in Arctic waters would have far-reaching and long-term impacts, although much remains unknown. More comprehensive understanding of baseline environmental conditions, potential trajectories of spilled oil, and the impacts of oil on Arctic species, ecosystems and communities is required prior to areas being approved for offshore exploration activities, including drilling.

8. As explained in section 7: An appropriate risk framework must distinguish among the acceptable, tolerable and unacceptable risks associated with the petroleum industry, including both the impacts of industrial activity on particularly sensitive areas and the risk posed by hydrocarbon releases. The framework must acknowledge that some risks are unacceptable and that continuous risk reduction is a requirement for projects and activities that are deemed tolerable.

Finally, the ‘polluter pays’ principle should fully apply, to enhance incentives for industry to avoid spills and to ensure funds are available for full response, cleanup, restoration and compensation.

9. As explained in section 8: Financial liability caps should be abolished and responsibility requirements significantly increased commensurate with the entire potential costs of any spill, including the environmental damages associated with a worst case scenario spill.

2 CHANCES OF A BLOWOUT

In our November submission, we questioned some of the industry SSRW submissions on the chances of a blowout. For example:

- We pointed out that Imperial's claimed probability of a blowout as one-in-100,000 includes estimated success rates for certain post-blowout same-well intervention techniques (such as reactivation of the BOP stack or placement of a second BOP stack on top of the first), that there was no consideration of the time it would take to apply such techniques even when they are available, and that Canada's Beaufort Sea is regarded as one of the most challenging offshore operating environments in the world.[4]
- We noted certain alternative estimates, such as BOEMRE's recent calculation that a deepwater blowout would occur once every 275 wells drilled, and that that frequency is no longer declining.
- We noted a significant number of possible additional risk factors in Arctic offshore drilling operations that were not explicitly considered in the industry SSRW estimates, such as ice incursions which "may require frequent and rapid planned disconnects."

As noted by Grace in his book "Blowout and Well Control Handbook:"

> "For as long as oil and gas wells have been drilled, there have been kicks, blowouts, well fires, and other control problems. It is certain that these problems will continue. In fact, a recent statistical study concluded that there are as many problems today as there were in the 1960s – which is rather startling considering the emphasis on regulation and training."[5]

The chances of an Arctic blowout must be taken seriously and the understanding needed to manage blowout risks must begin with an unflinching assessment of the likelihood of occurrence.

The following adds to our November submission by first referencing relevant information from the Commissions of Inquiry into the Macondo and Montara blowouts, and then by providing further details on the critique of the industry SSRW submissions regarding the chances of a blowout, other estimates, and possible additional risk factors in the Arctic.

2.1 Macondo

As overviewed in our November submission, certain industry submissions to the NEB's previous SSRW hearing claimed that new technology, improved experience, and the latest industry procedures and safety cultures had reduced risks to the point where the SSRW capability requirement was no longer needed. However, the Macondo blowout occurred despite these advances. For example, the *Deepwater Horizon* was a modern rig with an experienced and world record-setting crew:

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[4] See, for example, Chevron, Arctic Offshore Relief Well Equivalency, 2009, page 6.

[5] Blowout and Well Control Handbook, Grace, 2003, page 414.

> "*Deepwater Horizon*, built for $350 million, was seen as the outstanding rig in Transocean's fleet."[6]
>
> "According to BP's Patrick O'Bryan, the *Deepwater Horizon* was 'the best performing rig that we had in our fleet and in the Gulf of Mexico. And I believe it was one of the top performing rigs in all the BP floater fleets from the standpoint of safety and drilling performance.' … Despite all the crew's troubles with this latest well, they had not had a single 'lost-time incident' in seven years of drilling."[7]
>
> "the *Deepwater Horizon*, now owned by Transocean, continued to work away, setting the world's deepwater record for a semi-submersible at 9,576 feet of water. Just prior to moving onto the Macondo well project, it had set another world record, this time for drilling the deepest oil well in history at 35,050 feet vertical depth in 4,130 feet of water. In accomplishing these feats, the *Horizon* crew also set a record of seven years with no lost-time incidents, one of the key measures of safety performance in the oil field."[8]

Not only was the rig and crew impressive, but the companies involved were industry leaders:

> Transocean is "by far the largest offshore drilling firm in the world."[9]
>
> "Halliburton, BP's other major contractor for the Macondo well, is one of the world's largest providers of products and services to the energy industry. It has offices in 70 countries, and Halliburton-affiliated companies have participated in the majority of producing deepwater wells and contributed to most of the world's deepwater well completions."[10]

Moreover, these companies had apparently established procedures and safety cultures meant to ensure safety:

> "The *Deepwater Horizon* had two separate systems for collecting and displaying real-time data. The 'Hitec' system, owned by Transocean, was the source on which the *Deepwater Horizon's* drilling crew typically relied for monitoring the well. The 'Sperry Sun' system – installed and operated by a Halliburton subsidiary at BP's request – sent data back to shore in real time, allowing BP personnel to access and monitor this data from anywhere with an Internet connection."[11]
>
> "'Our goal of 'no accidents, no harm to people and no damage to the environment' is fundamental to BP's activities,' stated the company's Sustainability Review 2009. 'We work to achieve this through consistent management processes, ongoing training programmes, rigorous risk management and a culture of continuous improvement.' It

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[6] National Commission report, Jan 2011, page 2.

[7] National Commission report, Jan 2011, page 6.

[8] Disaster on the Horizon, Cavnar, Oct 2010, page 19-20. Similarly, see National Commission report, Jan 2011, page 51.

[9] National Commission report, Jan 2011, page 44.

[10] National Commission report, Jan 2011, page 224.

[11] National Commission report, Jan 2011, page 110.

> added that 'creating a safe and healthy working environment is essential for our success. Since 1999, injury rates and spills have reduced by approximately 75%.'"[12]

In addition, the latest sophisticated equipment was apparently being used. For example, as noted by the National Commission, once drilling on the Macondo well had been completed, "BP and its contractors, including Transocean, were able to spend the next five days between April 11 and 15 'logging' the open hole with sophisticated instruments."[13] As explained by Cavnar,[14] "Logs were run – measurements made with electrical, sonic, and gamma ray tools run on wireline – to give engineers and scientists a picture of the subsurface intervals, their content, and their pressures."[15]

Yet, despite all this, the Macondo well blowout occurred. Various explanations have been given, including complacency and poor judgement. However, the latest technology, experienced crews, and claimed safety cultures were clearly not enough to avoid catastrophic blowouts.

For example, questions have been raised about the effectiveness of certain claimed safety culture features, such as 'stop work authority:'

> "Even as companies like Transocean have safety observation programs, where employees are rewarded for pointing out unsafe practices, most of the results are somewhat superficial… Indeed, Transocean has a policy that anyone on the rig can shut down operations if they deem an operation unsafe. At the same time, employees can't name one time that anyone actually had the guts to do that. It looks good on paper, though, and sounds good in new-employee training classes."[16]

The National Commission concluded that it was not just poor judgement in this case:

> "The immediate causes of the Macondo well blowout can be traced to a series of identifiable mistakes made by BP, Halliburton, and Transocean that reveal such systematic failures in risk management that they place in doubt the safety culture of the entire industry."[17]

> "The blowout was not the product of a series of aberrational decisions made by rogue industry or government officials that could not have been anticipated or expected to occur again. Rather, *the root causes are systemic and, absent significant reform in both industry practices and government policies, might well recur* [our emphasis]. The missteps were rooted in systemic failures by industry management (extending beyond BP to contractors that serve many in the industry), and also by failures of government to provide effective regulatory oversight of offshore drilling."[18]

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[12] National Commission report, Jan 2011, page 218.

[13] National Commission report, Jan 2011, page 94.

[14] Bob Cavnar is described in his book on the Macondo blowout as follows: "A thirty-year veteran of the oil and gas industry, Cavnar has deep experience in drilling and production operations, start-ups, turnarounds, and management of both public and private companies… Previously, he was president and chief executive officer of Milagro Exploration – a large, privately held oil and gas exploration firm based in Houston, Texas, with operations along the Texas, Louisiana, and Mississippi Gulf Coast, and offshore in the Gulf of Mexico." See Disaster on the Horizon, Cavnar, Oct 2010, page 221.

[15] Disaster on the Horizon, Cavnar, Oct 2010, page 26.

[16] Disaster on the Horizon, Cavnar, Oct 2010, pages xiii-xiv.

[17] National Commission report, Jan 2011, page vii.

[18] National Commission report, Jan 2011, page 122.

2.2 Montara

The Montara blowout occurred while the *West Atlas*, a jack-up drilling rig, was completing five wells (one gas injection well and four production wells, the latter including the H1 Well that blew out) in approximately 77 metres of water at the Montara oilfield in a remote area of the Timor Sea off the north-west coast of Australia.[19] The Commission of Inquiry identified a number of 'direct and proximate' causes of the blowout, such as defective installation and failure to test the cemented shoe and removal of the 9 5/8" PCCC (pressure containing anti-corrosion cap),[20] but went on to note underlying causes, such as the operator "succumbing to the allure of time and cost savings,"[21] which is potentially a constant threat throughout the industry.

The Commission of Inquiry also identified deficiencies in regulatory oversight as a contributor to poor industry practice. The Commission concluded that the relationship between regulator and industry had become "far too comfortable", which led to a minimalist regulatory approach with "no effective monitoring or audit regime pursued by the regulator" and, as a consequence, no means of discovering inadequacies in oilfield practices.[22] This resulted in part from "a profound misunderstanding of what is required of a regulator".[23]

Together, the Macondo and Montara blowouts remind us that blowouts can and do occur in shallower and deeper waters, and during exploration and production drilling activities.

2.3 Critique of Imperial's and DNV's Claims on the Chances of a Blowout

As noted in our November submission, Imperial's SSRW submission claimed a very low likelihood of blowouts, relying on an attached DNV study. We discuss first DNV's study and then Imperial's summation of it. DNV and then Imperial carried out the following steps in coming up with their estimate and in making conclusions about it:

- Step 1: select data from other areas in the world.
- Steps 2, 3 and 4: exclude from the data selected in step 1: wells in shallow water, shallow gas incidents, and underground well releases.
- Step 5: account for an additional ram on the blowout preventer (BOP) stack.
- Steps 6, 7, 8: estimate success of an acoustic backup system, remotely operated vehicle (ROV), and a second BOP.

What follows is a critique of each of these steps followed by a critique of DNV's conclusions regarding its estimate and Imperial's summary of DNV's estimate.

[19] Montara Commission report, Jun 2010, pages 36-38 paragraphs 1.13-1.18, page 49 paragraphs 3.4-3.5.

[20] Montara Commission report, Jun 2010, page 60 finding 1, page 91 finding 9, page 110 finding 20.

[21] Montara Commission report, Jun 2010, page 127 paragraph 3.259.

[22] Montara Commission report, Jun 2010, page 60 finding 1, pages 16 and 217.

[23] Montara Commission report, Jun 2010, page 60 finding 1, page 16.

Step 1: DNV's initial dataset

DNV began with data on incidents in other parts of the world: the Gulf of Mexico, eastern Canada, Norway and the UK, none of which are from Arctic basins. The frequency of loss-of-well control events in the selected data was 83/15,800 or one incident per 190 wells drilled.

WWF-Canada believes the value of quantitative approaches to risk assessment can only be realized if risk analyses carefully document all assumptions and the uncertainties they entail, are peer reviewed and are ultimately clear enough to enable public understanding:

> "If data and assumptions used in these calculations are transparent, third parties can independently review and critique the analyses, facilitating analytic improvements and public acceptance of agency risk management choices." [24]

However, the SINTEF blowout database relied upon by DNV is confidential and access to it is available only to the oil companies and consultants that sponsor the database.[25] This creates a barrier to independent third parties who wish to verify that a risk analysis is founded upon the most appropriate data.

Industry has argued that the chance or likelihood of a blowout or release from Arctic offshore drilling would be acceptably low. Yet, there are no data that can directly confirm or refute their claim:

> "Due to the embryonic state of offshore oil development in arctic regions, which has been the case since 1976 to the present, it is not possible to base oil spill probability estimates on empirical data. The early studies relied on a detailed fault tree analysis dealing with the operations as systems without history. More recent studies in northern but not arctic operations use world wide data as a starting point."[26]

The likelihood of a blowout in the Arctic can only be inferred from probability models (fault tree analyses) and statistical data from non-Arctic sources. This does not mean that either approach or a combination of them is invalid. It does mean that any estimate of the probability of a blowout in this environment is only as good as the assumptions that have been combined to produce it: "With poor data, quantitative assessments can be highly variable or even manipulated, depending on the assumptions and other criteria used."[27]

It is also important to recognize the inherent limitations of fault tree models:

> "Fault tree analysis is a useful tool for the a priori calculation of risks. However its flaws lie in the over optimistic belief that all possible contingencies can be envisaged by the engineers and risk assessors using the tool. Hazardous operations such as drilling need to be thought of as a system. That system contains engineering sub-systems, procedural sub-systems, and behavioural/leadership sub-systems, all of which combine to create the system as a whole.
>
> Fault tree analysis is very useful with the engineering sub-system, can shed some light in the procedural sub-system, but is practically useless in the behavioural/leadership

[24] Montara Commission report, Jun 2010, pages 26-27; 31-32.

[25] SINTEF Database Description, Feb 2010.

[26] Bercha Arctic Offshore Oil Spill Probabilities, Sep 2010, page 1.

[27] Scarlett Risk Management Practices, Jan 2011, pages 22, 24

dimension. In stressful situations such as kicks and blowouts, poor leadership and behaviours often lead to failures in procedures and consequential failure of the system as a whole."[28]

Step 2, 3 and 4: Reducing the dataset

DNV next selected a subset of the data by excluding wells in relatively shallow water (< 100 m ocean depth), shallow gas events, and underground releases, which reduced the frequency of loss-of-well-control events in the remaining data to eleven of 5,611 selected wells, i.e. one incident per 510 wells.[29]

DNV excluded wells in shallow water because the study was commissioned by Imperial in relation to its planned deepwater well. As with the initial data selection, we could not independently confirm this step due to the confidentiality of the SINTEF database. The selection of only deep water wells means that DNV's estimate cannot be used in parts of the Arctic where shallow water drilling takes place. It is important to remember that blowouts also occur in shallow waters, that shallow gas events create safety and environmental hazards, and that underground blowouts can result in oil making its way to the seabed (which DNV appeared to acknowledge).

Step 5: Accounting for an Additional Ram on the BOP Stack

Of the eleven remaining incidents in DNV's study after the above steps, five were not stopped by blowout preventers, resulting in a DNV estimate of one incident continuing per 1,122 wells drilled.[30]

DNV next reduced its probability estimate by modelling the anticipated benefit of using a BOP stack with an additional blind shear ram and redundant hydraulic lines in Beaufort applications. This stack configuration increased DNV's estimate of the reliability of the system by a modest 0.32%, from 99% to 99.32%, which represents a much more significant 32% decrease in the probability of BOP failure on demand.[31] DNV estimated that one blowout would have continued for every 1,650 wells drilled had this stack configuration been used in the past.[32]

WWF-Canada acknowledges that BOP design improvements could help to prevent some blowouts. Yet, we doubt that enhancing the performance of the BOP system can produce a 32% reduction in the likelihood of a blowout for a number of reasons:

[28] Personal Communication – Greg Bourne, Former Regional President BP Group and Former Manager Drilling, BP Exploration UK, Mar 2011. For further discussion of the exacting requirements for a drill crew to detect and respond appropriately to an instability situation, see also van Vegchel, 2008.

[29] DNV Beaufort Sea Risk Study, Mar 2010, page 17.

[30] DNV Beaufort Sea Risk Study, Mar 2010, page 22.

[31] DNV Beaufort Sea Risk Study, Mar 2010, Table 4-7, page 22.

[32] The fractional improvement in the failure rate is (8.91×10^{-4} - 6.06×10^{-4})/8.91×10^{-4} = 32%. The back-calculation of a hypothetical uncontrolled flow frequency (p 23) appears unnecessary. The modeled failure probability has simply been reduced by 32%: 45.5% * (0.68% / 1.00%) = 30.9%.

- Equipment reliability data gathered during routine testing are not indicative of what happens under blowout conditions. Personnel and equipment exposed to escaping hydrocarbons and other hazards may not perform as anticipated.
- Many blowouts cannot, even in principle, be contained by activating blowout preventers. For blowouts immune to BOP control, stack design enhancements have no effect.
- As far as we can know, no tests were conducted in the Arctic and no allowance was made for the potential effects of exceptionally challenging Arctic conditions on BOP equipment reliability.

What follows is a brief discussion of each of these factors.

First, BOP system performance estimates such as those presented in DNV's Table 4-7 are derived from component reliability data that isolate equipment performance from the other factors that can lead to system failures during actual loss-of-well-control events. By contrast, human errors and blowout-induced malfunctions are determining factors in the outcomes of some blowouts. Consider this account of the role of human error in the BOP failure during the Macondo blowout:

> "The rig crew activated the BOP, at best, only moments before the blowout began. By then, hydrocarbons had already gone past the BOP into the riser and were expanding rapidly towards the rig floor. Even if the BOP had functioned flawlessly, the rig would have exploded and 11 men would have died."[33]

The delay in recognizing the urgency of the situation and attempting to activate the BOPs was a determining factor in this instance. Even if the BOP had functioned flawlessly, by the time it was tried, it was too late. BOP stack design improvements would have made no difference whatsoever.

And this:

> "Even if the blind shear ram activated, it failed to seal the well. One possible explanation is that the high flow rate of hydrocarbons may have prevented the ram from sealing. Initial photos from the recovered BOP show erosion in the side of the blowout preventer *around* the ram, which was a possible flow path for hydrocarbons…. Therefore even if the ram closed, the hydrocarbons may have simply flowed around the closed ram."[34]

What is significant here is that the blind shear ram might well have performed satisfactorily under routine test conditions, but failed under blowout conditions. The chance of equipment failure during blowout conditions is much higher than predicted by routine equipment testing.[35] In fact, DNV's post mortem of the Macondo well BOP stack revealed that blowout conditions caused the drill pipe to buckle in such a manner as to jam the blind shear rams, preventing them from closing and sealing the well.[36]

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[33] Media Release: National Commission Chief Counsel's Report, Feb 2011, page 2.

[34] National Commission Chief Counsel's Report, 2011, Chapter 4, page 212.

[35] Excluding events they attributed to operator errors, DNV calculated an equipment failure rate during blowout events of 18.2% (2/11), DNV, March 2010, p 27, substantially higher than the 1% estimate derived from test data, Ibid, Table 4-7, page 22.

[36] DNV Forensic Examination of Deepwater Horizon BOP, Mar 2011.Page 178.

Second, many offshore well blowouts are underground releases that flow to the sea floor either outside the casing or through the outer annulus. Bercha notes, for example that,

> "...for drilling blowouts, the flow path is outside the casing to a location on the sea bottom in 22% to 56% of the cases."[37]

> "This is very important to note because it means that in 22% to 56% of blowouts the BOP is completely ineffective as a method of controlling them. In other words a hypothetical super BOP which claims to control any blowout with 100% reliability would apply to 44% to 78% of blowouts and have no effect on the underground blowouts with flow path directly to the sea bottom."[38]

A DNV report prepared for the Norwegian industry association Oljeindustriens Landsforening and based on the most recent SINTEF data, reached a similar conclusion that 48% of all blowouts are 'subsea' events with a flow path outside the casing or through the outer annulus.[39] Blowouts that cannot, even in principle, be contained by activating BOPs cannot be reduced by BOP stack design improvements. At least one outside-the-casing blowout is included in the data DNV selected.[40]

DNV thus appears to have overstated the potential influence of BOP stack design enhancements on the chance of stopping a blowout. It is far from clear that the proposed stack modifications would have reversed the outcome in the five instances in the DNV-selected data in which BOPs did not stem blowouts.[41] The scope to reduce blowout probabilities by enhancing stack design is strictly limited first by blowout incidents that cannot, even in principle, be contained with such equipment and second by the prominence of blowout causal factors that BOP design cannot alleviate including certain operator errors[42], as well as equipment failures that are not mitigated by BOP design.

Third, we find it surprising that DNV's study, which purports to estimate the risk of a blowout in the Beaufort Sea, takes no account of the especially challenging conditions that would occur there, in effect assuming that BOP equipment reliability data from temperate basins can be applied without modification to the Arctic setting. The industry has little or no actual experience with attempting to control a well blowout under Arctic conditions.

[37] Bercha Arctic Offshore Oil Spill Probabilities, Sep 2010, Table 4, page 3.

[38] Bercha Arctic Offshore Oil Spill Probabilities, Sep 2010, page 3.

[39] DNV, Apr 2010, p 48-51 and Table 7-13, p 55. The probability of an outside-the-casing or outer casing underground release (48%) = probability of a subsea or seabed release (80%) * probability of flow path outside the casing or through the outer annulus (60%).

[40] DNV Beaufort Sea Risk Study, Mar 2010, page 38.

[41] DNV Beaufort Sea Risk Study, Mar 2010, pages 37-38. The Diamond Ocean Ambassador blowout was outside the casing – http://www.mms.gov/incidents/blow2002.htm. The Vinland blowout was attributed to human error. The operator waited too long to close the BOP. The Diamond Ocean Concord blowout was likewise caused by human error - the LMRP was accidentally disconnected. The Zapata Lexington blowout could not be stopped due to equipment failure.

[42] Bercha, Sep 2010, page 2 presents an estimate that 68% of blowout incidents are precipitated by human error.

Steps 6, 7 and 8: Estimate the success of acoustic backup, ROV and second BOP

DNV next investigated the likelihood that three mitigation measures would succeed or fail, leading to an estimate of the likelihood of a deepwater blowout that would not be mitigated by deploying acoustic backup systems, remotely operated vehicles (ROVs) or the installation of a second BOP stack. After these steps, DNV's estimate of a continuing blowout was reduced to 1:100,000.

The significant difficulties with these steps are threefold.

First, we have already explained why the chance of a blowout, which is the point of departure for this exploration of mitigation options, has been underestimated.

Second, DNV compounds the problem by extending the analysis with assumptions based on limited industry experience:[43]

> "Due to the absence of reliability data for Acoustic Backup Systems, the reliability on demand of the system was estimated to only be 75%."
>
> "There is limited information available on the likelihood of an ROV successfully regaining control of a blowout…"
>
> "…due to the limited data available regarding the use of a second BOP stack as a mitigation measure, the probability factors were discussed and agreed upon with the operator based on experience and the fact that landing a BOP stack on top of a wellhead is performed on a regular basis and is considered a routine operation." [44]

The assertion that "landing a BOP stack on top of a wellhead is performed on a regular basis within the industry and is considered a routine operation" is an example of an overly optimistic assumption. As the Macondo incident showed, landing a second BOP stack under blowout conditions is anything but routine.

Third, and once again, there appears to be no consideration that these measures might be more difficult under Arctic conditions.

We conclude that DNV's 1:100,000 estimate for the chance of an unmitigated deepwater blowout is built on an flawed estimate of the likelihood of a blowout and highly speculative assumptions about the effectiveness of same-well mitigation measures.

Critiquing DNV's conclusions

DNV presents an interpretation of its estimate that we cannot reconcile with the observation that hydrocarbons are released to the environment until a blowout is contained. DNV states:

> "This value [1:100,000] represents all possible consequence outcomes, ranging from a minor well control incident to a serious environmental event. A serious event is therefore a subset of this value, meaning an even greater period between occurrences." [45]

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[43] Our November submission, p 9-10; DNV Beaufort Sea Risk Study, Mar 2010, pages 25-27.

[44] DNV, Beaufort Sea Risk Study, Mar 2010, pages 25, 26.

[45] DNV, Beaufort Sea Risk Study, Mar 2010, pages 31-32. The value referred to is 1:10,000: "Assuming a constant drilling rate of 10 wells per year, the frequency of experiencing an uncontrolled flow event in the Beaufort Sea that

DNV is saying that the subset of blowout events in their estimate includes all events with consequences: both minor and major. Yet blowouts that are eventually controlled by an acoustic backup, ROV or a second BOP are excluded.[46] An uncontrolled hydrocarbon release will flow unabated unless and until one of these approaches succeeds, which can take some considerable time and have consequences. The Macondo disaster is one notable example of a blowout with serious consequences that would not be included in DNV's estimate because it was ultimately contained with a second BOP stack, albeit a custom-made capping stack..[47] . It demonstrates one of the fundamental problems with the DNV analysis – namely that it does not consider the time it would take to implement the 'mitigation' measures in steps 6, 7 and 8 above, or the amount of oil that could be spilled in the interim.

It is also difficult to see how DNV's estimate could be said to include all minor well control incidents. A blowout that prompts the deployment of all of these mitigation options and which nevertheless cannot be contained when these means are exhausted cannot be described as a 'minor well control incident.'

Critiquing Imperial's summary of DNV's study

In our November submission we highlighted passages from Imperial's SSRW submission summarizing the DNV study, in which the probability of a blowout was said to be either one-in-100,000 or one-in-285,000:

> "The analyses … demonstrate that the probability of a blowout from a deepwater drilling operation in the Beaufort Sea will be exceptionally low. i.e., about one in 100,000 wells or once in 10,000 years [assuming 10 wells are drilled per year]."[48] For context, the last glacial maximum ice age in the Beaufort Sea and Mackenzie Delta was about 14,000 years ago."[49]
>
> "Blowouts are very rare for the entire industry as well as for Imperial … the probability of a blowout is low – one in 285,000."[50]

The latter estimate appears to be from an earlier draft of the DNV report and we therefore restrict our comments to the remaining claim. The 1:100,000 figure Imperial refers to as the "probability of a blowout" is actually DNV's estimate of the probability of a deepwater blowout that cannot be brought under control after the fact by acoustic backup, ROV or a second BOP.[51] The erroneous statement about the probability of a blowout and comparison with events in geological time are therefore simply misleading.

cannot be resolved with the equipment on the drillship can be expressed in time as one occurrence every 10,000 years."

[46] DNV, Beaufort Sea Risk Study, Mar 2010, page 28.

[47] National Commission report, Jan 2011, page 162.

[48] Imperial SSRW submission, Mar 2010, page 4-1.

[49] Imperial SSRW submission Mar 2010, page 4-1.

[50] Imperial SSRW submission, Mar 2010, page 3-4.

[51] DNV, Beaufort Sea Risk Study, Mar 2010 pages 6, 7, 28.

2.4 Other Estimates of the Chances of a Blowout

In our November submission we mentioned a few other estimates of the chances of a blowout:

- We referred to a recent BOEMRE analysis that calculated one blowout would occur for every 275 deepwater wells drilled, that that number was no longer decreasing, and that there is a catastrophic deepwater blowout for every 4,123 wells drilled.
- We provided a 'back of the envelope' calculation for offshore drilling in Canadian waters that estimated one blowout would occur for every 162 wells drilled.

A risk analysis, commissioned by the U.S. Minerals Management Service (MMS) for drilling in the U.S. Beaufort Sea and published in 2008, assessed the frequency of occurrence of a blowout categorized by size of the resultant spills. Frequencies were provided for small and medium spills (50-999 barrels), large spills (1,000-9,999 barrels) and two categories of even larger spills (10,000 to 149,999 barrels and greater than 150,000 barrels). The analysis put the combined frequencies for deepwater exploration drilling blowouts that result in spills greater than 1,000 barrels at one occurrence for every 418 wells drilled. For spills greater than 150,000 barrels, which could be interpreted as being catastrophic events, the analysis estimates there will be one occurrence for every 2,822 deepwater wells drilled.[52]

These estimates suggest the following rounded estimates:

- A blowout occurs every 200 to 300 deepwater wells drilled.
- A serious blowout occurs every 400 deepwater wells drilled.
- A catastrophic blowout occurs every 3,000-4,000 deepwater wells drilled.

Given Imperial/DNV's assumption that about 10 wells will be drilled per year in the Canadian Beaufort Sea,[53] the above estimates would result in a blowout every couple of decades, a serious blowout every four decades or so, and a catastrophic blowout every few hundred years. Note again these estimates do not account for additional difficulties that might be encountered in Arctic drilling, and they mostly represent only blowouts from deepwater drilling so are but a fraction of all blowouts that could potentially occur from operations in the Beaufort Sea.

While predicting the likelihood of a blowout does not appear an exact science, the above estimates nevertheless paint a very different picture than that of Imperial's SSRW submission.

Finally, as an aside, full, fair and precautionary submissions from applicants to regulators should be part of a good safety culture. However, we were somewhat disturbed by some of the submissions presented by certain industry members which appeared more selective with advocacy in mind rather than attempting to provide 'full, fair and precautionary' information, as is evident from the critique in our November submission and in this submission. We suggest that regulators such as the NEB make it clear that the fulsomeness or otherwise of a company's submissions will be part of the measure of that company's safety culture.

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[52] Bercha Beaufort Oil Spill Occurrence Indicators, Mar 2008, Table 4.17, page 4.30

[53] DNV Beaufort Sea Risk Study, Mar 2010, page iii.

2.5 Possible Additional Risk Factors in the Arctic Offshore

Our November submission outlined a number of possible factors in the Arctic, such as adverse weather and pack ice incursions, that could elevate the chances and consequences of blowouts and other spills from offshore rigs. The exceptionally challenging conditions prevalent in this environment may disrupt essential functions such as station keeping, supply logistics, and the safety of frequent forced disconnects. The following provides some additional information on the factors relevant to the risk of an Arctic blowout.

2.5.1 First well in area, thus less knowledge of pressures and fracture gradient

As noted by the Alaska Department of Environmental Conservation:

> "Predicting gas pressures in the formation and determining the weight of the drilling mud to be used are the key factors to maintaining control of the well and preventing a well blowout."[54]

Deepwater wells in Arctic waters will be the first in that region where wells will be technically complex because the target formations are high temperature, high pressure (HTHP) diapir zones.[55] The first deep wells in the basin will not have the benefit of previous well-based knowledge of pressures and fracture gradient. Lack of such knowledge can result in, for example, lost returns, which can in turn increase the chances of a kick and thus of a blowout:

> "One challenge, though, is that if the driller weights up too much, the weight of the mud can actually overcome the strength of the rock below, with the fluids within it, and open fractures that will drain mud out of the hole. Losing mud into a formation lowers the hydrostatic pressure at the bottom of the hole, risking an influx of hydrocarbons into the well – and a blowout."[56]

Indeed, relative lack of prior knowledge is one reason why exploration drilling carries more risk than development drilling:

> "…'deep' drilling blowouts occur approximately twice as frequently during exploration drilling as during development drilling."[57]

> "In principle, drilling a development well is identical to drilling an exploration well. Nevertheless, mainly due to the increased reservoir knowledge, the historical blowout frequency for development drilling is lower than it is for exploration drilling. This is the main reason for making a distinction between development and exploration drilling."[58]

2.5.2 Multiple disconnects increase risk of a blowout

As noted in our November submission, multi-year ice incursions will force unplanned, and possibly urgent, disconnects, allowing little time for the usual temporary abandonment practices.

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[54] Alaska BAT Conference report, Jun 2006, page 15.

[55] Bercha Arctic Offshore Oil Spill Probabilities, Sep 2010, page 2.

[56] Disaster on the Horizon, Cavnar, Oct 2010, page 22.

[57] Offshore Blowouts, Holand, 1997, Table 6.12, page 85.

[58] Offshore Blowouts, Holand, 1997, page 26.

This is particularly concerning if end-of-season ice conditions prevent the rig from returning to the well till next season. As noted by Cavnar:

> "To make a well safe for abandonment, a cement plug is usually set below the mudline; then all seals are tested again before the riser is displaced with seawater prior to pulling the blowout preventer back to surface. Before unlatching the preventer, seawater is always displaced into the riser to prevent the heavier drilling mud from entering the ocean environment during the unlatching. Usually, however, several operations must be completed before displacement occurs. First, a lockdown sleeve is run into the casing hanger seal assembly to lock it into the casing head and prevent it from moving. Then the top cement plug is set."[59]

The National Commission likewise summarized the planned abandonment procedures for the Macondo well, highlighting the importance of the cement plug, lockdown sleeve, and careful risk assessment and management of any modifications to planned abandonment procedures.[60] It also explained that "the first step in the temporary abandonment was to test well integrity," and went on to describe in detail the positive- and negative-pressures tests.[61] In relation to the latter, for example:

> "the crew simulates the effect of removing the mud in the wellbore and the riser (and the pressure exerted by that mud) during temporary abandonment… Those heavy columns of mud exerted much more pressure on the well than the seawater that would replace them after temporary abandonment. Specifically, the pressure at the bottom of the well would be approximately 2,350 psi lower after temporary abandonment than before… If the test showed that hydrocarbons would leak into the well once it was underbalanced, BP would need to diagnose and fix the problem (perhaps remediating the cement job) before moving on, a process that could take many days."[62]

This raises the question of how appropriate temporary abandonment procedures, tests and remediation of any problems detected, could be carried out if a rig in the Arctic has to disconnect while undertaking various operations and leave due to the unexpected and rapid encroachment of multi-year pack ice or other Arctic conditions. And would the well be in a reliable state to then over-winter, given that such conditions presumably might not allow the rig to return that season?

2.5.3 Arctic weather & ice difficulties

Industry recognizes that pack ice conditions present a serious challenge. In fact, a very basic requirement for offshore drilling in this environment, dynamic positioning while drilling in pack ice, has not yet been proven.[63] Industry also recognizes the difficulties of operating over a shorter drilling season among challenging ice conditions. Chevron, in assessing 11 arctic basins as to degree of difficulty for platform drilling, ranked the Beaufort Sea the third most difficult

[59] Disaster on the Horizon, Cavnar, Oct 2010, page 28.

[60] National Commission report, Jan 2011, pages 103-104.

[61] National Commission report, Jan 2011, pages 105-109.

[62] National Commission report, Jan 2011, pages 105-106.

[63] Chevron SSRW Submission, Mar 2010, page 18.

basin after NE and NW Greenland in terms of operational challenges.[64] Limited access due to late season ice encroachment can also hinder cleanup efforts or blowout recovery measures and increase the potential for spills to persist through more than one season.[65] Arctic conditions can also make the consequences of a blowout more severe than they would be in other offshore drilling environments.[66]

Changing Arctic weather conditions could also present significant challenges for drilling a well. A study conducted by Eric Kolstad and Thomas Bracegirdle and published in Climate Dynamics in February 2009 found that the retreat of Arctic sea ice is causing severe weather events to move north into polar regions that formerly experienced calmer weather when they were covered in ice. Dubbed "marine cold-air outbreaks," these events include "explosive mid-latitude storms, polar lows and arctic fronts."[67] According to the study, polar lows are "intense small-scale cyclones" that "sometimes possess a structure similar to hurricanes" and winds associated with arctic fronts can sometimes reach hurricane force.[68] Such extreme weather events could increase the degree of weather-related risk for arctic drilling. The paucity of weather forecasting capabilities in northern latitudes also means that operators may have limited warning of approaching weather systems that may require disconnects.[69]

The multiple Arctic risk factors – HTHP diapir formations without previous well-based pressure and fracture gradient data, pack ice incursions, marine cold air outbreaks, remoteness and so on – make the Beaufort Sea an especially risky operating environment. In combination, their effect may be greater still. Sudden severe weather from marine cold-air outbreaks or adverse pack ice conditions could force a rig to retreat during the delicate primary control operations needed to enter a high pressure formation or during operations to bring a kick under control.

2.6 Preliminary Conclusions

Based on the above, the chances of a serious or catastrophic blowout resulting from drilling in Arctic waters do not appear insignificant. Past industry estimations of the chances of a blowout appear overly optimistic, especially in light of recent events. Given the additional risks and uncertainties in the Arctic combined with the very serious consequences, the potential for a blowout must be taken seriously. We conclude that the potential for a blowout must be carefully planned for, and appropriate measures to respond to them maintained or put in place (such as SSRW capability discussed in the next section).

[64] Chevron Arctic Relief Well Equivalency, Jan 2009, page 6.

[65] Chevron SSRW Submission, Mar 2010, page 21.

[66] Chevron SSRW Submission, Mar 2010, page 22.

[67] Extreme Weather in Arctic Regions, Feb 2009.

[68] Kolstad, Marine Cold-air Outbreaks, Nov 2007, page 872.

[69] True North Weather Consulting website.

3 SAME-WELL INTERVENTION TECHNIQUES

While of course same-well intervention techniques to bring a blowout under control are important, our November submission noted some of the potential difficulties:

- *Effectiveness:* techniques might fail (e.g. ROV and acoustic backup systems might be unable to re-activate the blowout preventers on the BOP stack), or might cause other problems such as an underground blowout and potential flow to the seabed.
- *Availability:* some or all techniques might be unavailable in the circumstances, such as when vessels or systems are unavailable or not able to access the area (due to Arctic weather or ice conditions perhaps), or when debris, damage or safety concerns do not permit access to the wellhead.
- *Timing:* it may take weeks or months for a technique to be prepared, attempted and succeed, and remote and difficult Arctic conditions (which might be the very conditions under which the risk of a blowout is heightened in the first place) would likely increase such times, thus pointing to a need for end-of-season cut-off dates to allow sufficient time for such techniques to be attempted.

Our November submission also noted the importance of using *conditional probabilities* when appropriate (i.e. it is often inappropriate to treat events as independent, because the causes of one might change the probability of another – for example, if blowouts in the Arctic are more likely to occur during bad weather or ice conditions, the subsequent probability of success of same-well intervention techniques would be decreased due to those same conditions).

The following adds to our November submission by first discussing the various same-well intervention techniques attempted at the Macondo and Montara blowouts, and then provides some additional references with regard to effectiveness, availability and timing.

3.1 Macondo

Various same-well intervention techniques were attempted to either collect or stop the flow of oil from the Macondo blowout. Unfortunately, the overall public impression was, as summed up by Cavnar's chapter title on the topic: "Top Cap, Top Hat, Top Kill, Capping Stack: Making It Up as We Go Along."[70] The following discusses each attempt, in the order they were conducted, following the blowout on April 20, 2010.[71]

Happily, the techniques did collect some of the oil during the blowout, and did eventually bring the blowout under control. Unhappily, most of the oil escaped, and these techniques took almost three months to stop the flow. And as the following demonstrates, each technique faced difficulties, all had questions as to their success, some had the potential for limiting the use of other techniques, and some raised serious concerns that they might in turn create other significant

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[70] Disaster on the Horizon, Cavnar, Oct 2010, chapter 9.

[71] See generally: Disaster on the Horizon, Cavnar, Oct 2010, chapter 9, pages 116-136; Analysis of Macondo containment and control attempts, Tyagi et al., Jan 2011; National Commission report, Jan 2011, chapter 5: Response and Containment; National Commission Staff Working Paper on Stopping the Spill, Jan 2011.

problems. Also noteworthy is the "massive effort" and "enormous resources" required to undertake these techniques. As noted by Doug Suttles, Chief Operating Officer for Exploration and Production at BP, "the size of its [BP's] presence in the Gulf of Mexico was a big advantage."[72] Obviously, the situation would be very different in the Arctic, presenting additional difficulties and likely more lengthy delays.

3.1.1 Activate the BOP – unsuccessful (Apr 20-May 5)

The BOP stack had two annular preventers and five sets of rams, including a blind shear ram and a casing shear ram.[73] Despite recent testing, however, it did not work when needed. As noted by the National Commission, the *Deepwater Horizon's* BOP stack was subjected to not only a "week of surface testing" before being lowered down to the wellhead, but also testing during drilling operations.[74] And as noted by Cavnar, "no one could explain how the rams that had worked perfectly and held pressure just hours before the blowout completely failed when they were needed for real. The BOP wasn't closed, and would never close."[75] As explained by the National Commission:

> "The *Deepwater Horizon's* BOP did not succeed in containing the Macondo well… Witness accounts indicate that the rig crew activated one of the annular preventers around 9:41 p.m., and pressure readings suggest they activated a variable bore ram (which closes around the drill pipe) around 9:46 p.m. Flow rates at this point may have been too high for either the annular preventer or a variable bore ram to seal the well… After the first explosion, crew members on the bridge attempted to engage the rig's emergency disconnect system (EDS). The EDS should have closed the blind shear ram, severed the drill pipe, sealed the well, and disconnected the rig from the BOP. But none of that happened… The BOP's automatic mode function (the 'deadman' system) should have triggered the blind shear ram after the power, communication, and hydraulics connections between the rig and the BOP were cut. But the deadman failed too."[76]

Beginning on April 21, BP attempted to use the remotely operated vehicle (ROV) backup actuation system.[77] Those attempts were reportedly delayed for about 20 hours due to concerns the pressure created by successful shut-in might create an underground blowout.[78] Attempts at actuation focused not only on the blind shear ram, but also on the other rams and the annular preventers, but were unsuccessful at stopping the flow.[79] All the time, as noted by the National Commission, "the flow of oil and sand continued to wear down the BOP's parts, making closure more difficult,"[80] highlighting the decreasing chances of success over time with such equipment

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[72] National Commission Staff Working Paper on Stopping the Spill, Jan 2011, pages 5-6.

[73] National Commission report, Jan 2011, page 93.

[74] National Commission report, Jan 2011, pages 92-93.

[75] Disaster on the Horizon, Cavnar, Oct 2010, page 123.

[76] National Commission report, Jan 2011, pages 114-115.

[77] National Commission Staff Working Paper on Stopping the Spill, Jan 2011, pages 3-4, 7-9.

[78] National Commission Staff Working Paper on Stopping the Spill, Jan 2011, page 4.

[79] National Commission Staff Working Paper on Stopping the Spill, Jan 2011, page 7.

[80] National Commission report, Jan 2011, page 138.

during a blowout.[81] And as noted by Cavnar, "The presence of two pieces of drill pipe inside the stack [also] made sealing impossible."[82]

It wasn't just the original BOP stack that had problems. As noted by Cavnar in relation to tests carried out on the two BOP stacks that were to be used for the relief wells:

> "During these tests, newly required by the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), these two BOPs failed four of the tests: Both the EDS [emergency disconnect system] and the deadman system failed due to bad valves, and the casing shear rams failed to close due to a faulty control pod. These failures occurred on fairly new BOP stacks, built in 2004 and 2005."[83]

3.1.2 Containment dome (a.k.a. cofferdam) – unsuccessful (May 6-8)

The 40 foot tall containment dome, lowered over one of the three leaks, was an attempt to capture some of the oil and flow it via a riser to Transocean's *Discoverer Enterprise*. As explained by Cavnar, "the results were almost instantaneous: failure. BP was forced to quickly halt its effort to capture the torrent of flowing oil due to hydrates that clogged the containment vessel."[84] Indeed, it appears the cofferdam got out of control for a while – as noted by the National Commission: "BP engineers told Lynch that they had 'lost the cofferdam' as the dome, full of flammable material, floated up toward the ships on the ocean surface. Averting a potential disaster, the engineers were able to regain control of the dome and move it to safety on the sea floor."[85]

Tyagi et al. note that it may have been possible to inhibit hydrate formation by using a synthetic base drilling fluid or methanol in the dome, but "because the flow rate was higher than the 15,000 bbls/day the *Enterprise* could process, the cofferdam would have filled with hydrocarbons, become buoyant, and failed even absent the hydrate issues."[86]

As noted by Tyagi et al., if hydrate and buoyancy problems can be overcome, collection devices such as the containment dome could potentially collect much leaked oil from a specific leak point. However, Tyagi et al. summarize a number of inherent weaknesses with such techniques: "Away from the leak source (cannot capture all of the leakage); temporary; … inability to seal the dome to the leak point; limited by surface handling capacity; [and] depends on continued connection to surface vessels (weather sensitivity)."[87] Arctic conditions might amplify some of these weaknesses. For example, there would be significantly fewer surface vessels and

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[81] As explained by Cavnar: "Long after the blowout and sinking of the rig, BP was indeed finally able to trigger all six sets of rams on the BOP after making repairs to the yellow pod and the plumbing on the stack, but the action did not successfully shut in the well. BP conceded, however, that erosion to the seals and damage prevented it from sealing. Rams are designed to slam shut, not be flowed through for extended periods of time, especially at the very high rates and pressures experienced during a blowout. Erosion of the ram faces and the bore was by then likely severe, further reducing the BOP's chances of ever actually shutting in the well and sealing it" (Disaster on the Horizon, Cavnar, Oct 2010, page 42).

[82] Disaster on the Horizon, Cavnar, Oct 2010, pages 122-123.

[83] Disaster on the Horizon, Cavnar, Oct 2010, page 44.

[84] Disaster on the Horizon, Cavnar, Oct 2010, page 123.

[85] National Commission report, Jan 2011, page 146.

[86] Analysis of Macondo containment and control attempts, Tyagi et al., Jan 2011, pages 4-5.

[87] Analysis of Macondo containment and control attempts, Tyagi et al., Jan 2011, page 5.

significantly more ice and cold weather problems (including the need for all vessels to leave the area under certain conditions) compared to the Gulf.

3.1.3 Riser insertion tube tool (RITT) – collected some oil (May 16-25)

By May 16, BP had installed a Riser Insertion Tube Tool (RITT) into the end of the broken riser to carry oil and gas up to the *Discoverer Enterprise*.[88] As described by Cavnar, the RITT was "essentially a straw stuck into the end of the wrecked riser to take oil to the surface… it captured only about 2,000 barrels per day at best … they were actually able to capture, for a short time, at a rate of 5,000 barrels per day, but they were unable to maintain it."[89] As with the containment dome above, the RITT depended on surface vessels to collect the flow, and thus this technique would presumably also not be available if surface vessels were either not available or had to leave the area (due to Arctic weather or ice conditions, for example).

3.1.4 Top kill and junk shot – unsuccessful (May 26-28)

As noted by the National Commission, although top kills and junk shots "are standard industry techniques for stopping the flow from a blown-out well … they had never been used in deepwater."[90] The top kill was combined with a junk shot in the hope that the 'junk' would hang-up on obstructions in the BOP stack (such as drill pipe or partially deployed rams) long enough to restrict the flow in order to increase the chances of success from pumping kill mud into the well.

Although "BP's top-kill team began work in the immediate aftermath of the initial efforts to trigger the BOP,"[91] it still took until May 26 (over a month after the blowout) until it was attempted. The junk shot also raised concerns that the junk might "block the mud from pushing hydrocarbons back into the reservoir," that it "could increase the pressure in and stress on the well and BOP stack," and that it "had the potential to clog the choke and kill lines, which could interfere with future source control operations."[92]

Three separate attempts at the top kill and junk shot were unsuccessful.[93] As described by Cavnar, "they couldn't get enough mud in the well bore deep enough to build hydrostatic pressure. The 'junk' they pumped in to bridge over the partially closed BOP and damaged riser didn't create enough restriction to help."[94] Tyagi et al. suggest that a higher mud pumping rate might have produced more success, although they note, "the actual pressure that would have been required in late May, and the actual limits on that pressure due to the risk of having a well integrity (e.g. rupture disk[95]) failure are not known."[96] "Failed rupture discs in the 16" casing,"

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[88] National Commission Staff Working Paper on Stopping the Spill, Jan 2011, page 12.

[89] Disaster on the Horizon, Cavnar, Oct 2010, page 125.

[90] National Commission report, Jan 2011, page 149.

[91] National Commission report, Jan 2011, page 150.

[92] National Commission Staff Working Paper on Stopping the Spill, Jan 2011, page 17.

[93] National Commission report, Jan 2011, page 150.

[94] Disaster on the Horizon, Cavnar, Oct 2010, page 128.

[95] The rupture disks in the 16" casing were designed to burst and bleed off pressure in case pressure built up and exceeded thresholds between the production casing and 16" casing, or outside of the 16" casing, so as to avoid the production casing or the 16" casing itself from collapsing, and thus "may play an important role in relieving annular

they explained, "could provide a flow path leading to underground blowout at the 18" casing shoe and, therefore, potential for hydrocarbons to broach to the seafloor."[97] Tyagi et al. thus surmised: "It is likely that a higher pump rate top kill option was not considered due to concerns about the BOP stack and well casing integrity. There was [also] considerable uncertainty regarding the actual flow rate."[98]

Tyagi et al. added, "Another unknown … is how fast the BOP stack restrictions and the choke and kill lines would have eroded,"[99] once again highlighting the powerful erosion during a blowout from fast-flowing hydrocarbons, sand and mud.[100] Although Tyagi et al. note that top kill and junk shot techniques do have the potential for stopping a blowout via a hydrostatic kill, they note: "The main weakness of a top kill approach is that it depends on a partially closed BOP stack to act as a flow restriction. If this restriction erodes due to the blowout flow and the mud pumped during the top kill, the operation might fail because sufficient pressure below the BOP stack cannot be generated no matter how fast the mud is pumped. If a top kill fails for this reason, the hydrocarbon flow rate after the attempt would most likely be higher than before."[101] Other weaknesses/limitations summarized by Tyagi et al. included, "required pumping rate to achieve kill unknown," and "pumping capacity of surface equipment."[102]

3.1.5 Top hat, choke & kill line collection – collected some oil (Jun 3-Jul 15)

By this time, BP had constructed seven different 'top hat' collection devices, to be prepared for failure of the top kill and to allow for different possible connection points.[103] The device employed, as described by Cavnar, was "essentially a containment dome designed to fit over the riser, on top of the LMRP [lower marine riser package], which is the top component of the blowout preventer."[104]

One difficulty was cutting away the rest of the riser, which was still connected to the LMRP. According to Cavnar, this was complicated by the fact that there were two pieces of drill pipe inside the BOP and the bent-over riser, and Cavnar suggests this is probably what jammed the diamond saw being used in an attempt to cleanly cut the riser. BP had to instead use a hydraulic shear to "make a more jagged cut."[105] Cavnar explains the consequences: "The rough cut

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pressure under certain circumstances" – see National Commission Staff Working Paper on Stopping the Spill, Jan 2011, pages 18-20, 38.

[96] Analysis of Macondo containment and control attempts, Tyagi et al., Jan 2011, page 11.

[97] Analysis of Macondo containment and control attempts, Tyagi et al., Jan 2011, page 7.

[98] Analysis of Macondo containment and control attempts, Tyagi et al., Jan 2011, page 24.

[99] Analysis of Macondo containment and control attempts, Tyagi et al., Jan 2011, page 11.

[100] The Alaska Department of Environmental Conservation have noted likewise: "When a blowout does occur, the well head and BOP can be significantly eroded by high pressure gas and produced sand" (Alaska BAT Conference report, Jun 2006, page 12).

[101] Analysis of Macondo containment and control attempts, Tyagi et al., Jan 2011, page 22.

[102] Analysis of Macondo containment and control attempts, Tyagi et al., Jan 2011, page 6.

[103] National Commission Staff Working Paper on Stopping the Spill, Jan 2011, page 22.

[104] Disaster on the Horizon, Cavnar, Oct 2010, page 128.

[105] National Commission Staff Working Paper on Stopping the Spill, Jan 2011, page 22.

precluded the use of the tighter-fitting LMRP cap, but BP had also designed a larger one that just set over the ragged top of the pipe."[106]

By June 8 the *Discover Enterprise* was collecting nearly 15,000 barrels of oil per day through the top hat and by June 16 the *Q4000* was processing and burning up to 10,000 barrels per day via the choke line, in total "less than half the flow."[107] By July 12 (just a few days before the capping stack stopped the flow) the *Helix Producer* was also collecting oil via the kill line.[108] The National Commission noted: "It is unclear whether BP could have increased its collection capacity more rapidly than it did. BP's Lynch said that the speed at which the company brought capacity online was limited solely by the availability of dynamically positioned production vessels."[109] Presumably the availability of such vessels to navigate to and operate in Arctic waters would be significantly less.

3.1.6 Capping stack and well integrity test – successful (Jul 15)

As described by Cavnar, the capping stack was "made up of a double ram cavity and a single cavity with both choke and kill lines installed with remote-controlled valves."[110] It was thus essentially a custom-built second, smaller BOP stack placed on top of the first.[111]

An initial problem was how to connect it onto the top of the first BOP. For starters, the BOP stack "was listing at two degrees from vertical."[112] As explained by Cavnar: "On top of the LMRP, which is the top component of the stack, are two connectors. One is the flex joint that allows the riser to move with the ocean currents or with the rig as it floats on the surface; the other is the riser connector that attaches the riser to the BOP stack itself. Being above the BOP, these components are not designed to withstand wellhead pressures that can go as high as 10,000 to 15,000 psi. Also, since the flex joint is designed to move, it is not a stable platform on which to set a new 150,000-pound capping stack… Because the flex joint was so compromised, BP engineers had to actually straighten it with a hydraulic jack and then shore it up with wedges to keep it from bending when the stack was put in place. Even stabilized, it was not designed to hold the kind of pressures possible from shutting this well in, but that is exactly what they were about to do."[113]

Tyagi et al. explained how pressures from shutting-in the well with the capping stack could have resulted in equipment failure or an underground blowout: "The risks associated with the sealing

[106] Disaster on the Horizon, Cavnar, Oct 2010, page 129.

[107] Disaster on the Horizon, Cavnar, Oct 2010, page 129.

[108] National Commission Staff Working Paper on Stopping the Spill, Jan 2011, pages 22-23.

[109] National Commission report, Jan 2011, page 160.

[110] Disaster on the Horizon, Cavnar, Oct 2010, page 130.

[111] National Commission report, Jan 2011, page 162.

[112] National Commission Staff Working Paper on Stopping the Spill, Jan 2011, page 27. As noted by Cavnar: "The rig settled to the bottom on its side, 1,300 feet to the north-west of the wellhead. The 5,000-foot riser parted in several places as it was pulled under, torquing the BOP and wellhead with tremendous stress as it fell" (Disaster on the Horizon, Cavnar, Oct 2010, page 121).

[113] Disaster on the Horizon, Cavnar, Oct 2010, pages 130-131. As similarly noted by Tyagi et al., the capping stack "may not have been as effective if the pressures required to shut-in the well were significantly higher than those observed. The capping stack was installed on the top of the Deepwater Horizon LMRP, which reduced the system's allowable pressure limits" (Analysis of Macondo containment and control attempts, Tyagi et al., Jan 2011, page 23).

cap were primarily related to the wellhead, the well's casing integrity, and the BOP stack's integrity… [Further,] When the capping stack was eventually installed, the well's integrity had almost certainly been reduced by erosion caused by the months of high flow."[114] And as explained by the National Commission, if there was a 'broach' or 'underground blowout': "From there, the hydrocarbons could rise through the layers of rock and flow into the ocean from many points on the sea floor. This would make containment nearly impossible, at least until the completion of a relief well."[115]

The "extremely complicated operation" to install the capping stack began on July 10, and was completed by July 12.[116] A temporary shut-in was then planned for 6 to 48 hours to test the condition of the well. As noted by the National Commission, "BP faced significant criticism of the wisdom of attempting the test, with Exxon and Shell raising concerns associated with shutting in the well that had yet to be considered by BP or the government. In the most extreme scenario, one industry expert suggested that an underground blowout could cause the sands around the wellhead to liquefy and the entire BOP to disappear into the sea floor."[117]

After further delay to allow for additional analysis, the 'well integrity test' began on July 15 when BP shut in the well with the capping stack. "For the first time in 87 days, no oil flowed into the Gulf of Mexico."[118] The pressures observed, however, were in the 'uncertain' range as to whether there was an underground leak. As noted by a National Commission working paper: "After an hour and a half, a consensus among the science advisors had developed: Oil was leaking into the formation, and the Coast Guard should order BP to reopen the capping stack and resume collecting oil from the well."[119] And as explained by the National Commission:

> "Keeping the capping stack shut could cause an underground blowout and, in the worst case, loss of a significant portion of the 110-million-barrel reservoir into the Gulf. This risk had to be balanced against the benefit of stopping the spill, a continuing environmental disaster. The government decision makers recognized that the public wanted the well plugged and the flow of oil into the Gulf stopped, but the risk of causing greater harm was real."[120]

The decision was made to continue to test, and with new modelling data suggesting the pressure readings might be due to reservoir depletion rather than underground leaks, and with "intense monitoring of the area around the wellhead,"[121] the well integrity test was progressively extended until the static kill in early August. The capping stack was thus a success.

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[114] Analysis of Macondo containment and control attempts, Tyagi et al., Jan 2011, page 12. Cavnar provided a lay-person analogy: "Think of this like a garden hose with a nozzle on the end. As long as the nozzle is open, the hose looks fine. As soon as you close the nozzle, the hose will leak through any pinholes or around the faucet as pressure builds inside" (Disaster on the Horizon, Cavnar, Oct 2010, page 133).

[115] National Commission, Jan 2011, page 158.

[116] National Commission report, Jan 2011, page 164.

[117] National Commission report, Jan 2011, page 164.

[118] National Commission report, Jan 2011, page 165.

[119] National Commission Staff Working Paper on Stopping the Spill, Jan 2011, pages 31-32.

[120] National Commission report, Jan 2011, page 166.

[121] National Commission report, Jan 2011, page 166.

3.1.7 Static kill with mud and then cement – successful (Aug 3-5)

With the well shut-in by the capping stack, a static kill was then attempted beginning on August 3 with mud. As explained by Cavnar, "As more mud is pumped in, hydrostatic pressure from the heavier mud will build, pushing the oil and gas back down the well and into the formation."[122] And as explained by a National Commission Staff working paper, "If successful, the kill would reduce or eliminate the pressure within the capping stack and hydrostatically contain the well during hurricane season."[123] BP followed the mud with cement, completed by August 5.

Again, as noted by the National Commission: "The primary concern with the static kill was the pressure it would put on the well."[124] Mr. Pat Campbell, a Vice-President at Superior Energy Services which owned Wild Well Control, recommended "in no uncertain terms that the static kill not proceed,"[125] because (as summarized by Tyagi et al.) "it was a higher risk alternative as compared to utilizing the relief well or some other circulating kill method."[126] Such concerns led Cavnar to ponder the reasons for a static kill: "The problems with this procedure are the integrity of the wellbore – here, one known to be damaged – and the limitations of the wellhead equipment, in this case the BOP and components (remember that flex joint)… The only reason I could think of for this procedure was that they were concerned about the worsening leaks on the flex joint and the old BOP and wanted to get the pressure off …"[127] Similarly, Tyagi et al. noted:

> "The contention by Mr. Campbell that bullheading mud creates a higher risk of loss of well and equipment integrity than circulating kill methods is widely recognized by the industry and, in the opinion of the authors, was well understood to be relevant in this case. Apparently, a decision was made that the risks associated with having the capping stack as the only barrier – e.g. of leaks, damage, or loss of component control – were greater than the risks that a casing rupture disk would burst or loss of pressure containment in some other well component would occur during the short term, slightly higher pressures (reportedly only about 35 psi higher) imposed during bullheading."[128]

Thus both Cavnar and Tyagi et al. raised concerns about relying on the capping stack alone for any length of time, and concluded that those in charge believed that a second barrier (namely hydrostatic pressure with mud) was required. In the Arctic context, this obviously raises questions about relying on a second BOP stack alone while waiting for a relief well that could not be completed in the same season. And although a hydrostatic barrier was established for Macondo via the static kill, Tyagi et al. noted that such a technique should not, "in the authors' opinion, … be expected to generally achieve such success in future situations."[129] They explained:

[122] Disaster on the Horizon, Cavnar, Oct 2010, page 134.

[123] National Commission Staff Working Paper on Stopping the Spill, Jan 2011, page 34.

[124] National Commission report, Jan 2011, page 167.

[125] National Commission report, Jan 2011, page 167.

[126] Analysis of Macondo containment and control attempts, Tyagi et al., Jan 2011, page 15.

[127] Disaster on the Horizon, Cavnar, Oct 2010, page 134.

[128] Analysis of Macondo containment and control attempts, Tyagi et al., Jan 2011, page 17.

[129] Analysis of Macondo containment and control attempts, Tyagi et al., Jan 2011, page 14.

> "In general, in wells with a significant span of open hole exposed… bullheading is only useful for displacing kick fluids from the cased hole and reducing surface pressures; it is not reliable for achieving a kill, and on multiple occasions, has resulted in a well experiencing underground flow (e.g. interzonal transfers or an underground blowout)."[130]

Although Tyagi at al. accepted that bullheading with mud was applicable in the particular circumstances of the Macondo well,[131] they did not feel the same way with regard to the bullheading of cement, noting that "bullheading cement carries risks and creates complications that the authors believe were inappropriate in this situation."[132] After noting that the blowout flow path(s) and connection(s) between the annulus and the inside of the well were unknown, they stated:

> "Therefore, the flow path and ultimate position of the cement pumped into the well could not be known. The position of the drillpipe in the well was also unknown, and it would likely be cemented into the well. These factors could have substantially complicated proper plug and abandonment of the Macondo well, and would have prevented use of the wellbore for a kill if later complications, such as a delay or problems in the relief well, occurred."[133]

> "A more serious concern was that the cement could have only partially blocked the flow path to the surface. This can occur when the set cement has permeability or leaks due to small channels, cracks, or microannuli… A long cement column in the well with this kind of leak would have prevented later attempts to fill the well with mud and use its hydrostatic pressure, i.e. with a riser margin …, to inhibit resumption of the blowout if control with the capping stack was lost."[134]

Again, such concerns would presumably be greater in an Arctic offshore context if a same-season relief well was not possible, and thus a static kill had to be relied upon for considerably longer.

3.1.8 New BOP– successful (Sep 4).

As explained by Cavnar, after several days of what was called the 'near ambient test', BP opened the well: "the well didn't flow, although it continued to burp oil and gas bubbles."[135] On August 16, Admiral Allen ordered BP to pull the capping stack and the old BOP stack to install a new BOP stack. According to Cavnar: "His reasoning was that during the eventual bottom kill [via the relief well], they were concerned about pressures exceeding the pressure ratings of three components on the stack,"[136] which Cavnar explains were "the flex joint …, the riser adapter on top of that, then the transition spool, or connection, between that and the new capping stack."[137] The new BOP stack was installed on September 4.

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[130] Analysis of Macondo containment and control attempts, Tyagi et al., Jan 2011, page 16.

[131] Analysis of Macondo containment and control attempts, Tyagi et al., Jan 2011, pages 14, 16-17.

[132] Analysis of Macondo containment and control attempts, Tyagi et al., Jan 2011, page 14.

[133] Analysis of Macondo containment and control attempts, Tyagi et al., Jan 2011, page 17.

[134] Analysis of Macondo containment and control attempts, Tyagi et al., Jan 2011, page 18.

[135] Disaster on the Horizon, Cavnar, Oct 2010, page 135.

[136] Disaster on the Horizon, Cavnar, Oct 2010, pages 135-136.

[137] Disaster on the Horizon, Cavnar, Oct 2010, page 136.

Finally, recalling the above comments on the possibility that the bullheaded cement might have only partially blocked the flow path, Tyagi et al. added: "Note that no second barrier (in addition to cement) was present when the BOP was actually replaced."[138] The importance of this was highlighted by Cavnar (when discussing the later relief well interception of Macondo):

> "The well was successfully intercepted on September 17th, confirmed by the relief well losing circulation, which is common, and pressure rising on the Macondo well blowout preventer, indicating communication with the reservoir, which you would expect if there was no cement in the hole. Since there was supposed to be cement in the well after the static kill, it's pretty obvious, then, that that procedure had not been the success it has been declared, and, indeed, the removal of the old blowout preventer was riskier than the unified command was letting on."[139]

3.2 Montara

Same-well intervention techniques were considered for the Montara blowout, but were not ultimately attempted, again demonstrating some of the difficulties and limitations on the availability of such techniques.

As noted by the Montara Commission, the operator of the Montara well (PTTEPAA) engaged the company ALERT Disaster Control to provide specialist advice and well control services in relation to the blowout.[140] ALERT recommended deluging the drilling rig (the *West Atlas*) with seawater to reduce the risk of ignition and fire, and to simultaneously prepare to both undertake surface capping of the H1 Well and to drill a relief well.[141] However, NOPSA (the National Offshore Petroleum Safety Authority in Australia) issued prohibition notices forbidding any activities that would place personnel at or near the *West Atlas* due to fears that the escaping hydrocarbons would ignite, and NOPSA was not convinced that the proposed deluging operation justified lifting the prohibition.[142] Nevertheless, it is noteworthy that in both the Macondo and Montara blowouts, experts believed that both same-well intervention techniques and a relief well should be undertaken simultaneously almost immediately following the blowouts.

The various same-well intervention techniques considered for Montara included capping the H1 Well, which would have involved first retracting the *West Atlas'* cantilever, placing a wellhead onto the 20" conductor casing, attaching a BOP stack onto that and activating it to stop the flow, then pumping kill weight mud into the well through the BOP stack, and finally setting mechanical plugs.[143] However, the operator itself (PTTEPAA) considered this operation too risky:

> "PTTEPAA's submission to the Inquiry stated that its assessment of the surface capping option was that it involved a significant risk to human life, not least because the operation required a number of personnel to board the WHP [Wellhead Platform] / *West Atlas* and

[138] Analysis of Macondo containment and control attempts, Tyagi et al., Jan 2011, page 19.

[139] Disaster on the Horizon, Cavnar, Oct 2010, page 150.

[140] Montara Commission report, Jun 2010, page 239 paragraph 5.18.

[141] Montara Commission report, Jun 2010, page 240 paragraph 5.19.

[142] Montara Commission report, page 238 paragraph 5.13, page 243 paragraphs 5.30-5.31.

[143] Montara Commission report, Jun 2010, pages 245-246 paragraph 5.37-5.38

work within the highly flammable gas cloud that engulfed the facilities at the time. The Inquiry understands that PTTEPAA did not proceed with the surface capping option because:

> "a. a real risk of fatality existed – approximately 25 to 30 per cent chance of death;
>
> "b. there was an increased risk of ignition introduced by personnel conducting work to retract the cantilever of the *West Atlas* in a highly flammable environment;
>
> "c. given NOPSA's rejection of PTTEPAA's submissions in relation to seeking to place water deluge vessels in the vicinity of the WHP / *West Atlas*, NOPSA was unlikely to accept a submission seeking to board personnel on the WHP / *West Atlas* to undertake surface capping of the H1 Well; and
>
> "d. the surface capping option was logistically difficult because it required:
>
> > "i. a specialised BOP designed with well kill functionality only (the BOP required to cap the H1 Well was not the standard BOP that was onboard the *West Atlas* at the time of the Blowout) to be sourced from Singapore; and
> >
> > "ii. a crane barge (or other heavy lifting vessel of a type that is not generally readily available) to be sourced and located very close to the *West Atlas*."[144]

Another factor weighing against attempting to cap the well was "that a successful surface capping operation would stop the Blowout only 11 days earlier than the forecast date for the conclusion of a successful relief well operation."[145] It is interesting to speculate what would have happened had a timely relief well not been possible – might there have been pressure to attempt the surface capping operation, and therefore to put personnel safety in jeopardy? This seems another important consideration as to whether the SSRW capability requirement should be maintained in Canada's Arctic, because without it more risky same-well intervention techniques might be the only recourse.

Two other same-well intervention techniques considered for Montara were referred to as "the subsea options," and involved either "crushing the casing at a point between the sea surface and the seabed in order to block the flow of hydrocarbons up the casing to the surface; or cutting and capping the casing underwater."[146] However, "PTTEPAA decided not to proceed with the subsea options because:

> "a. it was considered too risky for divers to enter the water in the vicinity of the WHP/*West Atlas*, and a Remote Operated Vessel (ROV) would be required to manoeuvre the 15 tonne machine required to crush the casing;
>
> "b. the 15 tonne machine required to crush the casing would have been very difficult to manoeuvre using a ROV;
>
> "c. cutting and capping the casing using a ROV may not have been effective in controlling the H1 Well, and may have compromised alternative intervention activity such as drilling the Relief Well;

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[144] Montara Commission report, Jun 2010, pages 246-247 paragraphs 5.39-5.41.

[145] Montara Commission report, Jun 2010, pages 246-247 paragraphs 5.39-5.41.

[146] Montara Commission report, Jun 2010, page 249 paragraph 5.47.

> "d. use of a ROV would have also required the presence of a support vessel in the vicinity of the WHP/*West Atlas*;
>
> "e. PTTEPAA considered that the risk to the safety of the personnel that would need to be involved was too high;
>
> "f. the risk of ignition was 'ever-present'; and
>
> "g. PTTEPAA anticipated that given NOPSA's rejection of PTTEPAA's submissions in relation to seeking to place water deluge vessels in the vicinity of the WHP/*West Atlas*, NOPSA was unlikely to accept a submission seeking to allow either of the two possible subsea options considered by PTTEPAA."[147]

Finally, a controlled ignition of the H1 Well was considered to burn the flowing hydrocarbons, but PTTEPAA explained this option was "ruled out on the basis of ALERT's advice that within 20 to 30 minutes we would collapse the drilling derrick … and that at some time after that there was the potential to collapse the rig itself onto the wellhead platform, and that would have caused significant problems with any future well control requirements, ie accessing the well, in order to secure it after you've done the relief well and the plug. We still had to get to the well at some point."[148]

Overall, the various same-well intervention options considered and rejected for the Montara blowout vividly demonstrates some of the limitations on the availability of same-well intervention techniques. And although the Commission found that PTTEPAA and NOPSA should have collaborated better in considering these various same-well intervention techniques,[149] the Commission of Inquiry concluded: "the Inquiry finds that in assessing the risks associated with controlling the H1 Well either at the surface (capping) or subsea, PTTEPAA was competent in arriving at its decision not to pursue these methods of well control in the light of the high degree of risk to the safety of personnel."[150]

3.3 Effectiveness of Same-Well Techniques – BOP Reliability

The discussion on Macondo above overviewed some of the problems with not only the original BOP stack but also with the BOP stacks to be used for the relief wells. It also overviewed some of the concerns that shutting-in the Macondo well with the original BOP or capping stack might lead to equipment failure or an underground blowout (with the possibility that the flow would then make its way to the seabed). Others have commented on problems with BOP stacks more generally. For example:

> "In 2009, a risk management organization, Det Norske Veritas (DNV), was commissioned to do a confidential study for Transocean on subsea BOP reliability, using a database of 15,000 wells drilled in North American waters and in the North Sea from 1980 to 2006. It found 11 cases of blowouts in deepwater wells where the BOP was required to be activated. Yet only in six cases were the BOPs successful in shutting in the wells and avoiding oil

[147] Montara Commission report, Jun 2010, pages 249-250 paragraph 5.49.

[148] Montara Commission report, Jun 2010, page 250 paragraph 5.52.

[149] Montara Commission report, Jun 2010, page 251 finding 58.

[150] Montara Commission report, Jun 2010, page 250 finding 57. Similarly, see page 273 paragraph 5.99.

> spilled in the surrounding water. DNV classified the failure rate at 45 percent. An earlier study, performed by West Engineering for the MMS in 2004, showed that of 14 recent newly built deepwater rigs, only 7 even tested their subsea BOP's ability to shear drill pipe. Of the seven BOPs tested, four failed to cut the pipe. West's conclusions were prophetic: 'This grim snapshot illustrates the lack of preparedness in the industry to shear and seal a well with the last line of defense against a blowout.'"[151]
>
> "There are a number of reasons that a BOP can fail to close. Subsea BOPs are complex, precision devices that operate under extreme conditions often controlled from the surface while in up to 10,000 feet of water. The units are subject to corrosion, hydrostatic pressure, high internal pressures, and near-freezing temperatures. Stresses from movement in the riser, the floating rig, and ocean currents are common."[152]
>
> "A problem that is continually observed is that the equipment doesn't function when needed."[153]

Recall also, as noted in the discussion on the probability of a blowout above, the flow path for a significant number of blowouts is outside the casing, and so the BOP stack (and thus same-well intervention techniques aimed at reactivating it or placing a second stack on top of it) are "completely ineffective" as a method of controlling the blowout.

3.4 Availability of Same-Well Techniques

The Macondo and Montara discussions above have explained why some or all same-well intervention techniques may not be available at all. A 2006 report from the Alaska Department of Environmental Conservation (ADEC), which describes their 2004 Best Available Technology (BAT) Conference, provides a few more examples of the unavailability of same-well techniques under certain conditions. One of the categories of technologies considered at the Conference was for well capping, for which two tools used by Boots and Coots Services were evaluated – an 'abrasive jet cutter' and 'voluntary well ignition and capping while burning.' Although the ADEC Evaluation Committee found both tools to meet the criteria for BAT, it noted:

> "It [the abrasive jet cutter] can also be used in all offshore environments, except under water or if the well head has 'cratered.' Under these circumstances, drilling a relief well may be the only feasible option."[154]
>
> "A limitation is that it is difficult to implement Voluntary Well Ignition and Capping While Burning at deep water operations. Under these circumstances, drilling a relief well may be the only feasible option."[155]

[151] Disaster on the Horizon, Cavnar, Oct 2010, page 36. Note the DNV study referred to here is, we understand, an earlier version of the DNV study that was attached to Imperial's SSRW submission.

[152] Disaster on the Horizon, Cavnar, Oct 2010, page 40.

[153] Blowout and Well Control Handbook, Grace, 2003, page 16.

[154] Alaska BAT Conference report, Jun 2006, page 53.

[155] Alaska BAT Conference report, Jun 2006, page 54.

3.5 Time for Same-Well Techniques to Succeed

Same-well intervention techniques for Macondo took almost three months until the flow was successfully capped. Future research and development, combined with preparations including prefabrication and staging of equipment such as containment domes and capping stacks nearby, might be able to reduce such time in the future. As noted by the National Commission, four of the major oil and gas companies have, in the wake of the Macondo blowout, formed the Marine Well Containment Company, and committed $1 billion to start-up costs.[156] While noting this "is a significant step toward improving well containment capability in the Gulf of Mexico,"[157] and after describing a parallel but "more modest" effort by Helix Energy Solutions, the National Commission went on to caution:

> "The Marine Well Containment Company and Helix spill containment proposals are promising, but they have at least two fundamental limitations. First, the systems are not designed to contain all possible catastrophic failures, only the next *Deepwater Horizon* type spill. For instance, while both systems are designed to contain quickly the kind of blowout that happened at Macondo, they would not be able to contain a spill of the type that occurred in the Gulf of Mexico in 1979 during the *Ixtoc* oil spill, where the rig collapsed on top of the well…
>
> "Second, and perhaps most important, it seems that neither the Marine Well Containment Company nor the Helix system is structured to ensure the long-term ability to innovate and adapt over time to the next frontiers and technologies. What resources, if any, either initiative will dedicate to research and development going forward are unclear. The Marine Well Containment Company, in particular, could become another Marine Spill Response Corporation … – an industry nonprofit initiative created in response to a major oil spill that becomes underfunded and fails to innovate over time – if it does not implement specific policies and procedures to monitor and guarantee its long-term readiness as well as funding and investment levels."[158]

Cavnar offered a similar mix of hope and caution: "I just hope these proposals work better than the last oil industry joint project – the Marine Spill Response Corporation [MSRC] formed after the *Exxon Valdez* spill. Supposedly, the MSRC's $80-million-per-year budget would give it the capability to clean up a massive offshore spill such as BP's. It became painfully obvious very early on [during the Macondo blowout] that it couldn't manage even a small percentage of its touted capacity."[159]

It remains to be seen what improvements can be made for the Gulf, and to what extent they can translate to the Arctic. At present, no well containment system has been designed, built and tested for the Arctic.[160] Moreover, because each blowout presents unique challenges necessitating a particular response, delays will no doubt still be encountered in many cases. In the Arctic, such delays are likely to be longer, given the remoteness, logistical challenges, difficult weather and ice conditions, etc. Thus an appreciable and confident decrease in the

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[156] National Commission report, Jan 2011, page 244.

[157] National Commission report, Jan 2011, page 244.

[158] National Commission report, Jan 2011, pages 244-245.

[159] Disaster on the Horizon, Cavnar, Oct 2010, page 180.

[160] Personal Communication, Susan Harvey, Harvey Consulting LLC, Mar 2010.

response time with same-well intervention techniques compared to Macondo may not be possible.

3.6 Preliminary Conclusions

Fortunately, after great efforts and much innovation, same-well intervention techniques did eventually stem the flow from the Macondo blowout. However, it took nearly three months to do so. And as the commentators quoted above have noted, all of the techniques attempted have limited application, unsure success, and other weaknesses, including the potential to cause other significant problems. With the Montara blowout, same-well intervention techniques were not attempted because of safety risks and other difficulties. If a timely relief well had not been available, however, there may have been more pressure to put people in harm's way.

In Arctic waters, a number of the difficulties in using same-well intervention techniques would presumably be amplified. For example, all techniques that rely on surface vessels could be unavailable under difficult Arctic weather and/or ice conditions. Remoteness and logistical challenges would likely further delay all attempts and present unique difficulties. And even if successful, questions have been raised above about the ability of certain same-well intervention techniques to reliably maintain control of the well while waiting for a relief well that may take, according to industry SSRW submissions, up to three or four seasons to complete in deeper waters if SSRW capability is not assured.[161]

In summary, there are numerous scenarios in the Arctic in which same-well intervention techniques would not be available, effective or timely. Nevertheless, same-well intervention techniques are of course important, and these containment and control methods should be improved and demonstrated for Arctic offshore application to reduce the probability of a long-duration blowout and to reduce the probability of all of the oil escaping during a blowout.

Even given such improvements, there will necessarily be circumstances when such techniques remain unavailable or ineffective. Thus, relief wells continue to be a necessary option for blowout control, and so WWF-Canada concludes the SSRW capability requirement should be maintained (see next section). In turn, this necessitates maintenance of appropriate end-of-season cut-off dates, not only for SSRW capability but also to allow sufficient time to attempt same-well intervention techniques which can take months even without the additional challenges in the Arctic.

[161] See our November submission, section 4.2.

4 SAME-SEASON RELIEF WELL (SSRW) CAPABILITY

Our November submission provided information supporting the argument that relief wells provide an important method for bringing a blowout under control that need to be available in addition to same-well intervention techniques. For example:

- We noted BOEMRE's reemphasis, following the Macondo blowout, of operators providing information on arrangements for timely relief well drilling if needed.
- We raised the question of drilling simultaneous relief wells, albeit noting this would introduce new risks associated with drilling the second well.
- We disputed claims in certain industry SSRW submissions that the SSRW capability requirement is 'too prescriptive.'
- We disputed industry claims that modern well control methods and same-well intervention techniques, including new or additional rams on the BOP stack, are somehow 'equivalent' to the SSRW capability requirement. This discussion highlighted the important diversity that relief wells bring to the set of response techniques for bringing a blowout under control, given that relief wells (which approach the original well from some distance away and provide a method of bottom kill) are fundamentally different to same-well intervention techniques (which need access of the top of the original well and have to contend with the hydrocarbons flowing from it). We thus noted the importance of explicitly determining all such benefits that SSRW capability brings.

The following adds to our November submission by first describing the virtually immediate mobilization of relief well drilling for both the Macondo and Montara blowouts, and then provides some further references on the importance and reliability of relief wells, as well as further disputing industry claims that the SSRW capability requirement is too prescriptive.

4.1 Macondo

The National Commission explained how relief wells were very quickly considered a "primary" response technique for the Macondo blowout:

> "As BP realized that the early efforts to stop the flow of oil had failed, it considered ways to control the well other than by triggering the BOP. A primary option was to drill a relief well to intersect the Macondo well at its source and enable a drilling rig to pump in cement to stop the flow of oil. While it could take more than three months to drill, a relief well was the only source-control option mentioned by name in BP's Initial Exploration Plan. Industry and government experts characterized a relief well as the only likely and accepted solution to a subsea blowout. BP had begun looking for available drilling rigs on the morning of April 21 [the day after the blowout]; it secured two, and began drilling a primary relief well on May 2 and a back-up well insisted upon by Secretary Salazar on May 17."[162]

[162] National Commission report, Jan 2011, page 132.

A Staff Working paper for the National Commission added a few extra details:

> "Doug Suttles, Chief Operating Officer for Exploration and Production at BP, characterized a relief well as a standard industry technique for stopping a blowout, but said he believed at the time of the blowout that the drilling would take approximately 100 days. Several experts from both industry and government described relief wells to Commission staff as the only accepted, high-probability solution to a subsea blowout, even though they take months to drill."[163]

The National Commission noted that, after failure of the top kill and junk shot in late May, "BP and the government focused on trying to collect the oil, with the relief wells still providing the most likely avenue for killing the well altogether."[164] Although the capping stack stopped the flow in mid-July, the first relief well was finished "to finally kill the Macondo well,"[165] and, after cement was pumped into the bottom of the Macondo well, "on September 19, 152 days after the blowout, Admiral Allen announced: 'the Macondo 252 well is effectively dead.'"[166]

4.2 Montara

Just as with Macondo, a relief well was considered almost immediately following the Montara blowout. Following the blowout which began on August 21, 2009,[167] "between 21 and 23 August 2009, PTTEPAA made enquiries of several operators as to the availability of a suitable drilling rig located in the vicinity of the Montara Oilfield for the purposes of drilling the Relief Well. By 23 August 2009, PTTEPAA had contracted the Atlas-owned *West Triton* jack-up rig, which at the time was not under contract, but which was located in Batam, Indonesia."[168] Thus, "whilst simultaneously considering alternative options, PTTEPAA commenced preparations to drill the Relief Well in the immediate aftermath of the Blowout."[169]

The *West Triton* arrived on scene on September 11 (three weeks after the blowout began), and commenced relief well drilling operations on September 13 from a location approximately 2km from the site of the blowout.[170] On the fifth attempt it successfully intercepted the H1 Well on November 1, and on November 3 stopped the flow of hydrocarbons by pumping kill weight mud down the relief well, 75 days after the blowout began.[171]

4.3 Do Timely Relief Wells Provide an Important Insurance Policy?

As discussed above in the section on same-well intervention techniques, such techniques are not always available or effective, and can themselves cause additional problems, all pointing to the

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[163] National Commission Staff Working Paper on Stopping the Spill, Jan 2011, page 5.

[164] National Commission report, Jan 2011, page 158.

[165] National Commission Staff Working Paper on Stopping the Spill, Jan 2011, page 36.

[166] National Commission report, Jan 2011, page 169.

[167] Montara Commission report, Jun 2010, page 235 paragraph 5.1.

[168] Montara Commission report, pages 252-253 paragraph 5.55.

[169] Montara Commission report, page 239 paragraph 5.17.

[170] Montara Commission report, page 257 paragraphs 5.64 and 5.68.

[171] Montara Commission report, pages 261-263 paragraph 5.72 and accompanying table.

importance of timely relief wells being available. Likewise, a 2006 report from the Alaska Department of Environmental Conservation (ADEC) that reports on their 2004 Best Available Technology Conference, notes the following in a discussion of source control technologies for blowouts:

> "In some instances, the only practical way to control a well blowout, particularly for offshore platforms, ice islands or gravel islands, is to drill a relief well. A relief well may be the preferred alternative when a blowout can be capped but cannot be shut-in without risking an underground blowout. A relief well may also be an alternative when a serious pollution problem requires the well be ignited to limit environmental damage, yet it is not practical to cap the well while burning."[172]

And in describing John Wright Company's[173] presentation on relief wells, the ADEC report notes:

> "In some instances, a Relief Well is the only practical way to control a well offshore, particularly for close wellhead bays on the platforms in Cook Inlet, subsea wells, casing failures, or broaches. If a well blowout cannot be safely capped while on fire, a relief well can be drilled to control the well while the blowout is left to burn."[174]

Cavnar and Grace explain the evolution of relief wells and how they have become a reliable method for bringing a blowout under control:

> "Relief wells have been used for years to get blowout wells under control, but today they are not really 'relief' wells in the sense of relieving pressure in the blowout reservoir. In the early days, that's exactly what they were: When a well was blowing out, another well … was simply drilled vertically as close as possible to the blowout well, then produced at a high enough rate to lower the pressure in the reservoir to stop the uncontrolled flow. Then, in 1933, everything changed; directional relief wells were born, designed to kill the blowout well by applying hydrostatic pressure to get it to stop flowing."[175]

> "Modern technology has made intercepting the blowout a certainty and controlling the blowout from the relief well a predictable engineering event."[176]

> "In summary, relief well technology has advanced to the extent that relief well operations are now a viable, reliable alternative in well control operations and should be considered in the overall planning and management of a blowout. A recent blowout at a deep, high-pressure well in the North Sea is a good example. More than a year of expensive surface work failed to provide a solution to the problem. After many expensive months, the

[172] Alaska BAT Conference report, Jun 2006, page 15.

[173] John Wright is considered one of the best in the business, and is now with Boots & Coots. As explained by Cavnar in discussing the relief wells for the Macondo blowout: "Right after the blowout, Boots & Coots got the call from BP. John Wright was the man they wanted to get a relief well drilled to stop the monster roaring into the Gulf of Mexico 5,000 feet below the water's surface, and he is, by far, the most qualified person on the planet to be running relief well drilling operations. Of the last 83 relief wells drilled, John has managed 40, and all 40 have been successful" (Disaster on the Horizon, Cavnar, Oct 2010, page 145).

[174] Alaska BAT Conference report, Jun 2006, page 39.

[175] Disaster on the Horizon, Cavnar, Oct 2010, page 146.

[176] Blowout and Well Control Handbook, Grace, 2003, page 317.

> blowout was finally controlled from the relief well. There is a good chance that the relief well would have been just as successful in the first 60 days of the operation."[177]

4.4 Is the SSRW Capability Requirement Too Prescriptive?

A number of industry submissions to the NEB's aborted SSRW hearing argued the SSRW capability requirement was too prescriptive and "inconsistent with a modern, goal-oriented regulatory regime." As we pointed out in our November submission, however, a purge of all prescriptive requirements was never the intent of a goal-oriented approach. Both the Macondo and the Montara Commissions re-emphasized this.

4.4.1 Macondo

The National Commission did not feel US regulators were being too prescriptive. On the contrary, the Commission felt more requirements, both prescriptive and performance-based, were required, and emphasized that such requirements supplement one another.[178] For example:

> "Regulators … failed to keep pace with the industrial expansion and new technology – often because of industry's resistance to more effective oversight. The result was a serious, and ultimately inexcusable, shortfall in supervision of offshore drilling that played out in the Macondo well blowout and the catastrophic oil spill that followed."[179]

> "MMS regulations were inadequate to address the risks of deepwater drilling. Many critical aspects of drilling operations were left to industry to decide without agency review. For instance, there was no requirement, let alone protocol, for a negative-pressure test, the misreading of which was a major contributor to the Macondo blowout. Nor were there detailed requirements related to the testing of the cement essential for well stability."[180]

> "The record shows that without effective government oversight, the offshore oil and gas industry will not adequately reduce the risk of accidents, nor prepare effectively to respond in emergencies. However, government oversight, alone, cannot reduce those risks to the full extent possible. Government oversight … must be accompanied by the oil and gas industry's internal reinvention: sweeping reforms that accomplish no less than a fundamental transformation of its safety culture."[181]

> "Even in industries with strong self-policing, government also needs to be strongly present, providing oversight and/or additional regulatory control – responsibilities that cannot be abdicated if public safety, health, and welfare are to be protected… Industry self-policing is not a substitute for government but serves as an important supplement to government oversight. And the cost of forgetting that essential premise can be calamitous."[182]

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[177] Blowout and Well Control Handbook, Grace, 2003, pages 336-337.

[178] US regulators have issued new prescriptive and new performance-based requirements since the Macondo blowout, namely the new Drilling Safety Rule and the new Workplace Safety Rule (BOEMRE press release on new rules following Macondo blowout, Sep 2010).

[179] National Commission report, Jan 2011, page xiii.

[180] National Commission report, Jan 2011, page 126.

[181] National Commission report, Jan 2011, page 217.

[182] National Commission report, Jan 2011, page 234.

In northern Canada, as industry seeks to move into more remote, deeper, and more ice-prone Arctic waters, with all the additional challenges and risks such conditions bring, it seeks at the same time to have the NEB relax the requirement for SSRW capability. This brings to mind some of the National Commission's summary of the history of US regulation of offshore drilling. For example:

> "Any revenue increases dependent on moving drilling further offshore and into much deeper waters came with a corresponding increase in the safety and environmental risks of such drilling. Those increased risks, however, were not matched by greater, more sophisticated regulatory oversight. Industry regularly and intensely resisted such oversight, and neither Congress nor any of a series of presidential administrations mustered the political support necessary to overcome that opposition. Nor, despite their assurances to the contrary, did the oil and gas industry take the initiative to match its massive investments in oil and gas development and production with comparable investments in drilling safety and oil-spill containment technology and contingency response planning in case of an accident."[183]

> "When [in the late 1990s] industry contended that blowout-preventer stacks – the critical last line of defense in maintaining control over a well – were more reliable than the regulations recognized, warranting less frequent pressure testing, MMS conceded and halved the mandated frequency of tests. Soon afterward, a series of third-party technical studies raised the possibility of high failure rates for the blowout preventers' control systems, annular rams, and blind-shear rams under certain deepwater conditions and due to changes in the configuration and strength of drill pipe used by industry."[184]

Clearly, maintaining a healthy scepticism of industry claims is also important.

4.4.2 Montara

The Montara Commission likewise emphasizes the necessity of maintaining an appropriate balance of both prescriptive and performance-based requirements. The Commission acknowledged some of the important benefits of the shift to goal-oriented (i.e. objective-based) regulation in the UK and subsequently in Australia following Lord Cullen's report on the *Piper Alpha* disaster, such as putting responsibility for safety on operators by requiring they systematically identify and manage risks, allowing for operators to customize and innovate safety procedures and equipment, and avoiding 'tick-box' mentality.[185] While noting that the Commission, "certainly does not favour any major move back to a regime which specifies detailed standards for every aspect of an offshore facility," the Commission went on to state:

> "However, the current regulatory regime has effectively eliminated all levels of prescription in relation to well integrity, defaulting to an undefined standard of 'good oilfield practice'. This has left regulators with an ambiguous standard to rely on when assessing applications submitted by operators. The Inquiry considers that this ambiguity is likely to have contributed to very basic requirements of well integrity being overlooked by both

[183] National Commission report, Jan 2011, page 56.

[184] National Commission report, Jan 2011, pages 73-74.

[185] Montara Commission report, Jun 2010, pages 177-178 paragraphs 4.64-4.69, page 188 paragraph 4.108.

> PTTEPAA and the NT DoR. This suggests that the pendulum may have swung too far away from prescriptive standards.
>
> "A balance between prescriptive standards and technical innovation and flexibility must be achieved. In attempting to strike an appropriate balance, a stead-fast eye must be kept on the ultimate goal of health, safety and environmental protection."[186]

The Montara Commission also noted the importance of regulators maintaining a healthy scepticism. For example:

> "Recommendation 64: Supervision/oversight of well control operations (within licensees, rig operators and by regulators) must occur without assuming adherence to good oilfield practice. The opposite assumption should prevail: namely adherence to good oilfield practice may well be compromised by the pursuit of time and cost savings."[187]
>
> "the regulator cannot be passive in any type of regime – performance-based, prescriptive or hybrid."[188]
>
> "while it is incumbent on owner/operators to fully assess risks and to provide all relevant information to the regulator, regulatory authorities should not assume that they will do so."[189]

4.5 Preliminary Conclusions

As explained in previous sections, the probability of blowouts is not insignificant, and there are numerous scenarios in which same-well intervention techniques are either not available or not effective. Thus same-season relief wells (SSRWs) continue to be a necessary option for blowout response. And as explained above, in both the Macondo and Montara blowouts, relief wells were almost immediately considered a primary response technique, and numerous commentators have explained that relief wells are a reliable and one of the most accepted solutions to a subsea blowout. Further, as explained in our November submission, modern well control methods, including additional or new rams on the BOP stack, are not equivalent to same-season relief wells.

WWF-Canada therefore concludes that the SSRW capability requirement should remain in place for all offshore Arctic drilling, and that appropriate end-of-season cut-off dates should be maintained to allow time for relief well operations. If completion of relief well operations cannot be assured in the same season, drilling should not be approved.

Mr. Greg Bourne, a former regional drilling manager and regional president for BP, expressed the requirement as follows:

> "Exploration in hostile environments with short operational windows, as characterized by Arctic drilling, is extremely expensive. Development and production costs, should the

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[186] Montara Commission report, Jun 2010, page 188 paragraphs 4.108-4.110. Similarly, see Montara Commission report, Jun 2010, page 232 Recommendation 66.

[187] Montara Commission report, Jun 2010, page 159.

[188] Montara Commission report, Jun 2010, page 162 paragraph 4.4 quoting Mr. Danenberger. See also page 195 paragraphs 4.130-132.

[189] Montara Commission report, Jun 2010, page 232 finding 52(e)(i).

> exploration wells prove successful, are similarly extremely expensive by at least an order of magnitude. Necessarily this means that the types of reservoir and structures being sought have to be naturally pressured to over pressured, highly productive and large in volume.
>
> These reservoirs and structures area usually drilled into in the late stages of the well only matters of weeks away from the closing operational window leaving little or no time for a same season relief well (SSRW). There is only one responsible binary decision prior to "drilling-in" to the potential reservoir and structure: to go ahead and drill-in knowing that there is sufficient time for a SSRW or not to drill-in but rather suspend and return in a subsequent season. Permission to drill-in should only be given by the regulator if and only if a SSRW could be drilled, with equipment on hand, and with a sufficient time safety margin." [190]

As explained by the National Commission in relation to the additional challenges in Arctic waters:

> "Bringing the potentially large oil resources of the Arctic outer continental shelf into production safely will require an especially delicate balancing of economic, human, environmental, and technological factors. Both industry and government will have to demonstrate standards and a level of performance higher than they have ever achieved before. One lesson from the *Deepwater Horizon* crisis is the compelling economic, environmental, and indeed human rationale for understanding and addressing the prospective risks comprehensively, before proceeding to drill in such challenging waters."[191]

During the SSRW hearing, however, certain industry members asked the NEB to discard the SSRW capability requirement for Arctic waters, at least when drilling in deeper waters. But dropping the requirement for SSRW capability at the very time that industry moves into deeper, more remote Arctic waters with higher incidence of multi-year pack ice incursions and shorter open water seasons, would represent a reduction in standards as challenges increase, the very opposite of the higher standards called for by the National Commission.

[190] Personal Communication, Greg Bourne, former Regional President, BP Group and former Manager, Drilling, BP Exploration UK., Mar 2011.

[191] National Commission report, Jan 2011, page 305.

5 RESPONDING TO SPILLED OIL

Our November submission we challenged over-confident industry claims concerning the effectiveness of cleanup in Arctic waters. We explained in some detail that overall spill cleanup effectiveness is limited by the product of all of the following limiting factors:

- *Logistics* – given the remoteness, lack of infrastructure, transportation challenges, weather and ice, and relatively small population in the North, the scale of effort that could be mounted in response to a spill in Arctic waters would be very much less than elsewhere, and delays are likely to be significantly greater.
- *Response gap* – even without logistical difficulties, there will be significant periods of time when response efforts will not be possible due to ice conditions, fog, darkness, wind, sea state, temperature or wind chill.
- *Tracking* – when logistical and response gap difficulties allow for response efforts to be mounted, the next challenge is finding the moving oil, which is especially difficult if it is under or encapsulated in ice. Delays due to logistical difficulties or the response gap further amplify the challenges of finding the oil.
- *Techniques* – at such times that the logistical, response gap and tracking difficulties can be overcome, one or more of the three main methods of response (mechanical containment and recovery, in situ burning, and dispersants) can be attempted, although each has limited effectiveness.

Our November submission we explained how the above four factors combine to result in only a tiny fraction of spilled oil being expected to be cleaned up, and we referenced a recent Pew report that provided a compelling explanation as to why the results of small-scale controlled laboratory and field tests do not scale up to real world conditions. The Pew report also discussed the inherent environmental tradeoffs of *in situ* burning, such as the production of soot and residues from partial combustion and the added toxicity of dispersants.[192]

Given the detail with which we considered this issue in our November submission, the following simply adds some relevant references to the Macondo and Montara Commission reports, and then makes some preliminary conclusions.

5.1 Macondo

The National Commission report in discussing response efforts to the spill from the Macondo blowout noted both over-confident claims and the lack of any significant improvement in oil spill cleanup technology:

> "Twenty years after the *Exxon Valdez* spill in Alaska, the same blunt response technologies—booms, dispersants, and skimmers—were used, to limited effect."[193]

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[192] Pew Environment Group, Nov 2010. Oil spill prevention and response in the U.S. Arctic Ocean: unexamined risks, unacceptable consequences.

[193] National Commission report, Jan 2011, page ix.

> "BP's oil-spill response plan for the Gulf of Mexico claimed that response vessels provided by the Marine Spill Response Corporation and other private oil-spill removal organizations could recover nearly 500,000 barrels of oil per day.
>
> "Despite these claims, the oil-spill removal organizations were quickly outmatched. While production technology had made great advances since *Exxon Valdez* …, spill response technology had not … Though incremental improvements in skimming and boom had been realized in the intervening 21 years, the technologies used in response to the *Deepwater Horizon* and *Exxon Valdez* oil spills were largely the same.
>
> "… Congressional investigation revealed that the response plans submitted to MMS by ExxonMobil, Chevron, ConocoPhillips, and Shell were almost identical to BP's – they too suggested impressive but unrealistic response capacity and three included the embarrassing reference to walruses [which do not occur in the Gulf]."[194]

The National Commission summarized the updated estimates of how much oil released by the Macondo blowout was recovered, burned, or chemically dispersed:[195]

- Direct recovery from wellhead via containment: 17%.
- Skimmed: 3%.
- Burned: 5%.
- Chemically dispersed: 16%.

Corresponding numbers for an Arctic spill would presumably be lower, perhaps very much lower, given the additional logistical, response gap, tracking and technique limitations noted in our November submission.

With regards to chemical dispersants, as noted by the National Commission their use has been described as a "tradeoff of bad choices:"

> "Using dispersants has several potential benefits. First, less oil will reach shorelines and fragile environments such as marshes. Second, animals and birds that float on or wade through the water surface may encounter less oil. Third, dispersants may accelerate the rate at which oil biodegrades. Finally, responders to an oil spill can use dispersants when bad weather prevents skimming or burning. But dispersants also pose potential threats. Less oil on the surface means more in the water column, spread over a wider area, potentially increasing exposure for marine life. Chemically dispersed oil can be toxic in both the short and long term. Moreover, some studies have found that dispersants do not increase biodegradation rates – or may even inhibit biodegradation.
>
> "… Some toxicologists have questioned the reliability and comparability of the testing by manufacturers. Moreover, the required testing is limited to acute (short-term) toxicity studies on one fish species and one shrimp species; it does not consider issues such as persistence in the environment and long-term effects."[196]

[194] National Commission report, Jan 2011, pages 132-133.

[195] National Commission report, Jan 2011, page 169.

[196] National Commission report, Jan 2011, pages 143-144.

The National Commission added: "Timing matters, because the chemicals are most effective when oil is fresh, before it has weathered and emulsified,"[197] highlighting the further difficulties that are likely to be encountered in the more remote Arctic where response time is likely to be slower. Indeed, the Commission noted more generally: "The remoteness and weather of the Arctic frontier create special challenges in the event of an oil spill. Successful oil-spill response methods from the Gulf of Mexico, or anywhere else, cannot simply be transferred to the Arctic."[198]

Although criticizing the relative lack of research and development over past years to improve cleanup technology and practices, the National Commission nevertheless concluded there may be some potential room for improvement:

> "Though some commentators and industry representatives have argued that more research and development would not have allowed for a more effective spill response because no technology will ever collect more than a fraction of spilled oil, the fact is that neither industry nor government has made significant investments in improving the menu of response options or significantly improved their effectiveness. Thus any argument about the limited potential of response technology is speculative. After the *Deepwater Horizon* spill, agencies, industry, and entrepreneurs focused attention on developing new response technologies for the first time in 20 years, and a number of promising options emerged within a relatively short period of time – including beach-cleaning machines, subsea dispersant delivery systems, and new in situ burning techniques."[199]

The National Commission recommended the funding, development and implementation of a comprehensive interagency research program to address oil spill containment and response in the Arctic.[200]

5.2 Montara

The Montara blowout occurred in a remote area off the Northwest coast of Australia, and so provides some insight into some of the difficulties that a cleanup operation in Arctic waters might face (albeit without the cold weather, ice, etc). The Montara Commission noted the response operation "was of a complexity and magnitude rarely experienced, particularly because of the remoteness of the operation,"[201] and noted "the associated delays this would cause in mobilising a response operation."[202] The Commission highlighted the resulting "limitations to potential containment and recovery operations in the remote offshore environment (including effectiveness, safety concerns and time required to initiate action),"[203] and hence the decision to

[197] National Commission report, Jan 2011, pages 143-144.

[198] National Commission report, Jan 2011, page 303.

[199] National Commission report, Jan 2011, page 269.

[200] National Commission report, Jan 2011, page 304.

[201] Montara Commission report, Jun 2010, page 279 paragraph 6.2.

[202] Montara Commission report, Jun 2010, page 281 paragraph 6.8(a).

[203] Montara Commission report, Jun 2010, page 283 paragraph 6.11(b) and (c).

rely primarily on dispersants. And although the Montara Commission concurred with the decision to use dispersants,[204] it noted:

> "There are valid concerns about the use of dispersants because of the significant impacts dispersant/oil mixes can have on subsurface organisms such as fish larvae and coral spawn. It is not always the case that dispersants should be used in open waters since they necessarily involve adding a further pollutant to the sea. However, it must be acknowledged that there is no response option which will avoid all environmental impacts."[205]

A "300m containment boom incorporating a 'skimmer' to recover oil"[206] was also deployed. The Montara Commission noted:

> "In its submission AMSA [Australian Maritime Safety Authority] noted that it is relatively unusual for such containment and recovery operations to be possible in open waters where even a low swell and moderate winds can make booms ineffective. The clean-up of Montara oil was facilitated by the favourable climatic conditions which allowed the recovery of 844,000 litres of oil water mixture over 35 days of operations. Of this amount, it is estimated that some 493,000 litres was oil or oil emulsion. AMSA indicated that this represents approximately 10 per cent of the total oil spilled and is in line with international experience with such operations."[207]

Thus just 10% of the oil was estimated to have been recovered, although it was noted even this is "relatively unusual" and was only possible due to "favourable" weather and sea conditions.

5.3 Preliminary Conclusions

Based on the above and on our November submission, WWF-Canada concludes that industry claims that cleanup in Arctic waters can be effective come from small-scale controlled experiments that do not extrapolate to real world conditions. Rather, only a tiny fraction of spilled oil can be expected to be recovered from a blowout in the Arctic. Any assessment of the potential consequences of a spill or blowout should take this into account, and significantly improved cleanup of spilled oil must be demonstrated under real-world conditions in Arctic waters before cleanup can be relied upon as a meaningful mitigation measure.

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[204] Montara Commission report, Jun 2010, page 285 finding 80.

[205] Montara Commission report, Jun 2010, pages 284-285 paragraphs 6.16-6.17.

[206] Montara Commission report, Jun 2010, page 285 paragraph 6.18.

[207] Montara Commission report, Jun 2010, page 285 paragraph 6.19.

6 SOCIAL-ECOLOGICAL IMPACTS OF SPILLED OIL

Our November submission provided a brief overview of some of the impacts of spilled oil and of related knowledge gaps. For example:

- We noted generally some of the impacts that spilled oil can have on organisms throughout the food chain, and thus on overall ecosystem functionality.
- We noted that the characteristics of many Arctic species put them at heightened risk from impacts from oil spills, and that spilled oil may have particular impacts in Arctic waters in polynyas and leads which concentrate marine life, oil and response activities in the same place.
- We quoted a number of recent studies explaining the significant gaps in knowledge in both baseline ecological information about Arctic marine ecosystems and species, as well as gaps in knowledge of the effects of spilled oil on them.

The following adds to our November submission by referencing some relevant passages from the Macondo and Montara Commission reports, by discussing the potential volume of oil that might be spilled during a blowout, and by making some preliminary conclusions.

6.1 Macondo

The National Commission summarized some of the ways that oil from the Macondo blowout can affect wildlife in and around the Gulf:

> "Organisms are exposed to oil through ingestion, filtration, inhalation, absorption, and fouling. Predators may ingest oil while eating other oiled organisms or mistaking oil globules for food. Filter feeders – including some fish, oysters, shrimp, krill, jellyfish, corals, sponges, and whale sharks – will ingest minute oil particles suspended in the water column. Surface-breathing mammals and reptiles surrounded by an oil slick may inhale oily water or its fumes. Birds are highly vulnerable to having their feathers oiled, reducing their ability to properly regulate body temperature. Moderate to heavy external oiling of animals can inhibit their ability to walk, fly, swim, and eat. Similarly, oiling of plants can impede their ability to transpire and conduct photosynthesis, and oiling of coastal sediments can smother the plants they anchor and the many organisms that live below."[208]

However, the National Commission noted that a great deal is unknown about the impacts from the oil released during the Macondo blowout:

> "Unfortunately, comprehensive data on conditions before the spill – the natural "status quo ante" from the shoreline to the deepwater Gulf – were generally lacking. Even now, information on the nature of the damage associated with the released oil is being realized in bits and pieces: reports of visibly oiled and dead wildlife, polluted marshes, and lifeless deepwater corals. Moreover, scientific knowledge of deepwater marine communities is limited, and it is there that a significant volume of oil was dispersed from the wellhead,

[208] National Commission report, Jan 2011, page 176.

> naturally and chemically, into small droplets. Scientists simply do not yet know how to predict the ecological consequences and effects on key species that might result from oil exposure in the water column, both far below and near the surface."[209]

Even less is known in Arctic regions than in the Gulf – as noted by the National Commission, "equivalently detailed geological and environmental information does not exist for the Arctic exploration areas of greatest interest for energy exploration – and industry and support infrastructures are least developed, or absent, there."[210] The Commission added: "It is known that these are vibrant living systems, but scientific research on the ecosystems of the Arctic is difficult and expensive. Good information exists for only a few species, and even for those, just for certain times of the year or in certain areas."[211]

Nevertheless, given what is known, the National Commission provided some words of caution in relation to exploration in Arctic offshore waters:

> "Oil-eating microbes probably broke down a substantial volume of the spilled crude [from the Macondo blowout in the Gulf], and the warm temperatures aided degradation and evaporation – favourable conditions not present in colder offshore energy regions. (Oil-degrading microbes are still active in cold water, but less so than in warmer water.)"[212]

> "The stakes for drilling in the U.S. Arctic are raised by the richness of its ecosystems. The marine mammals in the Chukchi and Beaufort are among the most diverse in the world, including seals, cetaceans, whales, walruses, and bears. The Chukchi Sea is home to roughly one-half of America's and one-tenth of the world's polar bears. In November 2010, the U.S. Fish and Wildlife Service ruled that a large part of the polar bears' 'critical habitat' included sea ice in the Beaufort and Chukchi Seas. The Chukchi and Beaufort Seas also support millions of shorebirds, seabirds, and waterfowl, as well as abundant fish populations."[213]

6.2 Montara

The Montara Commission commented on the extent of the oil spill from the Montara blowout: "it is estimated that the total area across which patches of sheen or weathered oil products from the Blowout were observed could have been as large as 90,000 km^2."[214] Fortunately, impacts from the Montara blowout on a National Nature Reserve, Marine Reserve, and coastline in the region "were largely avoided."[215] However, as the Commission went on to note:

> "The extent of the pollution was nevertheless significant. Both oil and oil dispersants can have a toxic effect on sea birds, marine mammals and other megafauna, corals, coral larvae, and fish larvae, affecting photosynthesis, respiration and reproduction. It is not possible to

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[209] National Commission report, Jan 2011, page 174.

[210] National Commission report, Jan 2011, page 301.

[211] National Commission report, Jan 2011, page 303.

[212] National Commission report, Jan 2011, page 174.

[213] National Commission report, Jan 2011, page 303.

[214] Montara Commission report, Jun 2010, page 303 paragraph 6.83.

[215] Montara Commission report, Jun 2010, page 298 paragraph 6.63.

draw any firm conclusions at this stage about the damage caused by the oil and the dispersants used to break the oil down in the marine environment. Adequate data is not available."[216]

"[O]bservations have provided only partial data about wildlife fatalities. Animals that may have died in oil affected water may not have stayed afloat for very long, making it unlikely that that they could be detected in large numbers in the vast area of open water over which the oil and oil residue was dispersed. The impact of the Blowout on less visible but more delicate organisms, such as coral spawn and fish larvae, may be profound but may not become apparent for some years, if at all."[217]

"It is unlikely that the actual impact of the Blowout on wildlife and the environment will ever be known. There is little evidence that the Inquiry can draw on to illustrate the consequences. This does not mean that they are not real or substantial. Rather, the area is vast and remote and there is no firm data available against which pre and post spill comparisons can be made. Ongoing and long-term Scientific Monitoring may assist in getting a better understanding of the extent of the consequences, although this is doubtful in part because the monitoring was delayed in its formulation and implementation."[218]

6.3 Volume of Oil Spilled From a Blowout

The amount of oil spilled per day from a blowout will vary. Estimates for the Montara blowout were on the order of 200 to 1500 barrels per day.[219] Over the course of the Macondo blowout, between 53,000 and 62,000 barrels of oil per day spilled into the Gulf. The Montara blowout was estimated to have released about 30,000 barrels of oil in total over 74 days; the Macondo blowout about 4.9 million barrels over 87 days. The amount of oil spilled during a blowout therefore appears to heavily depend on the characteristics of the reservoir and the path the escaping oil takes as it escapes through or outside the well (and thus the amount of resistance presented).

In an analysis conducted for the Norwegian offshore industry, DNV discussed some of the paths escaping oil may take during a blowout, the probability that oil will escape through the various paths, and the amount of oil per day that could flow through each path.[220] The analysis was carried out for an area off the coast of Norway where high temperature/high pressure reservoir conditions are not found. The flow rates for the various flow paths modelled ranged between 3,900 barrels per day (619 m^3) and 80,400 barrels per day (12,787 m^3).[221] Flow rates associated with the highest probability flow paths were between 25,000 and 42,000 barrels per day.

In the section on same-well intervention techniques above, we noted the timeframes for each activity attempted to stem the flow of oil during the Macondo blowout. For example, efforts to

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216 Montara Commission report, Jun 2010, page 306 paragraph 6.87.

217 Montara Commission report, Jun 2010, page 307 paragraphs 6.89-6.90.

218 Montara Commission report, Jun 2010, page 298 paragraph 6.64.

219 Montara Commission report, Jun 2010, page 301 paragraphs 6.76-6.77.

220 DNV Nordland VI Risk Assessment, Apr 2010, Section 7.

221 Flow rates have been converted from standard cubic metres (provided in the DNV Nordland VI report) to barrels using a conversion factor of 6.29 barrels per cubic metre.

close the BOP stack with the ROVs went on for about 16 days, while the drilling of a relief well required about 140 days.

There are unfortunately no readily available data to determine what flow rates could be expected deepwater for a blowout on the Beaufort Sea slope. Recognizing that reservoir conditions, and resultant flow rates, can vary widely throughout the world, we have applied the DNV flow rates for Nordland VI to the timeframes required for mitigation of the Macondo blowout to establish a starting point for discussions over what the potential consequences might be should a blowout occur in the Beaufort Sea. We caution that these preliminary projections should be considered speculative.

Applying the flows from paths that DNV says have the highest likelihood of occurrence (25,000 to 42,000 barrels per day) to the times it took for each mitigation step during the Macondo blowout, we see that up to 672,000 barrels of oil could escape just while ROV operations are being attempted to reactivate the BOP stack. If it takes 140 days for a relief well to stem the flow of oil (assuming no quicker same-well intervention technique is successful), up to 5.9 million barrels of oil could be discharged through flow paths with the highest likelihood of occurrence. Of course, the amount of oil released would be much greater if the relief well could not be completed in the same season, leaving the blowout unchecked for up to a year or more.

Finally, note that deepwater wells drilled in the Beaufort Sea may encounter high-temperature, high-pressure reservoir conditions, and so the flow rates per day could be higher than those predicted in the DNV Norwegian analysis which were based on normal reservoir pressures.

6.3.1 Worst case scenario

Neither the petroleum industry nor the American government were prepared to cope with a disaster of the magnitude of the BP *Deepwater Horizon* blowout when it occurred. This is not surprising since the regulator and the industry were effectively assuming that such an event would not occur.[222] The now discredited Minerals Management Service (MMS) based its decisions on the more palatable average consequences of past spills.[223] The purpose of reviewing worst-case scenarios is not to fixate on unlikely events, but to make rational decisions about risk, by understanding what is possible.

For example, an 'almost worst case' scenario for the Beaufort Sea might involve a well that blows early in the drilling season and is contained in the same season, 140 days later. Such an event could spill some 11 million barrels, more than twice the volume of oil from the Macondo[224] if the flow rate was 80,000 barrels per day, the highest estimate in the DNV Nordland VI study.

In another 'almost worst case' scenario, suppose a blowout occurred on September 27, midway through a 158-day drilling season that begins on July 10 and ends on December 15.[225] Again, assuming a relief well is required to bring the blowout under control and it takes 140 days of

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[222] Houck, Worst Case and the Deepwater Horizon Blowout, 2010 and references therein. See also National Commission report, Jan 2011.

[223] MMS required consideration of the mean of previous spills. MMS publication No 2007 – 003, Outer Continental Shelf Oil and Gas Leasing Program 2007-2012, cited in Houck, 2010.

[224] Assumes: 80,000 barrels per day for 140 days needed to complete the relief well. The 80,000 bpd figure is an estimate of an open hole, BOP open flow from the DNV Norwegian study.

[225] Chevron SSRW Submission Mar 2010, historical drilling season dates on Slide 29.

drilling, the relief well would not be completed until September 8 of the following season. The blowout in this scenario would flow for 343 days, and assuming a flow path with the highest flow rates, it would release 27 million barrels of oil into the Beaufort Sea.

As noted in our November submission,[226] industry describes their ability to drill a same season relief well in deeper Arctic waters as ranging from unlikely to impossible. For example, Imperial stated: "For most circumstances in deepwater, completing a relief well operation in a single season is impossible,"[227] and would "take longer to drill than the original exploration well, likely three to four seasons."[228] In a situation such as this where a multi-year relief well might be needed, the capacity of the reservoir becomes relevant. The Macondo well was drilled in a hydrocarbon reservoir thought to contain 110 million barrels of oil.[229] A blowout that lasted three or four years would release an immense amount of oil into the Beaufort Sea, likely enough to exhaust the pressure of the reservoir, before a relief well was completed. Such an event would surely constitute a worst case scenario.

6.4 Preliminary Conclusions

A significant oil spill in Arctic waters would have far-reaching and long-term impacts, although much remains unknown. More comprehensive understanding of baseline environmental conditions, potential trajectories of spilled oil, and the impacts of oil on Arctic species, ecosystems and communities is required prior to areas being approved for offshore exploration activities, including drilling.

The amount of oil spilled per day during a blowout can vary depending on reservoir characteristics and flow path. A blowout that could not be brought under control by same-well intervention techniques and that had to wait for a relief well that Imperial suggests could take three or four seasons if SSRW capability is not ensured could result in a worst-case scenario that dwarfs the amount of oil released during the Macondo blowout. Given the inability to effectively cleanup such oil in Arctic waters, the ecological damage could be staggering.

[226] See page 23, section 4.2.

[227] Imperial SSRW submission, Mar 2010, page 4-7.

[228] Imperial SSRW submission, Mar 2010, pages 8-9.

[229] National Commission report, Jan 2011, page 165.

7 RISK FRAMEWORK FOR ARCTIC OFFSHORE ACTIVITIES

There is an enormous literature on risk assessment and risk acceptance and WWF-Canada cannot fully discuss in this submission. We will, however, identify the key features of a risk framework and underline the strengths and shortcomings of only two approaches, one employed by DNV in Imperial's March SSRW submission and another that is prevalent in Canada. We do not regard either as complete; however, both have features that could be combined into a risk framework that captures their respective strengths. We conclude by providing a few examples of where an effective risk framework should generate a conclusion of unacceptable risk.

7.1 Key features that should be present in a risk framework

1. The framework should encompass the risks associated with both high likelihood events (such as shipping noise, minor spills and leakage) and low-likelihood events (such as blowouts).

2. The framework should apply whether the primary concern is to understand and manage the risks of particular activities, projects or policies, or to understand and manage the combined risks associated with multiple activities and projects to specific ecological endpoints in particular geographic areas. An example of the activity-focused approach would be an effort to understand and manage the risks associated with a specific piece of technology. An example of an outcome-focused approach might weigh the potential cumulative impacts of proposed activities on areas that are particularly sensitive.

3. The framework must allow for the possibility of unacceptable risk, such that a project or activity may be deemed too hazardous, or an area too sensitive to sustain any industrial activity.

4. The framework must provide for continual improvement, so that surpassing a certain threshold does not result in a disincentive to ongoing efforts to further reduce risk.

5. The framework must take a precautionary approach to decision-making in the absence of adequate baseline information.[230] By making decisions based on cautious assumptions where there is a wide margin of error, the incentive is provided for generating the knowledge needed to close information gaps.

7.2 Strengths and limitations of existing risk frameworks

As we noted in our November submission, the Canadian Association of Petroleum Producers (CAPP) endorses the ALARP (as low as reasonably practicable) principle. The value of the principle, if properly applied, is that it promotes the ongoing reduction of risk. However, CAPP described their understanding in the following way in testimony before the House of Commons Standing Committee on Natural Resources:

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[230] Arctic Council Offshore Oil and Gas Guidelines, 2009, section 2.2. page 16: "If data is insufficient to define risk criteria, then the risk assessment should also incorporate the precautionary principle as reflected in Principle 15 of the Rio Declaration."

> "achieve a risk level that is as low as reasonably practicable without eliminating the possibility of conducting an activity."[231]

The problem with this conception of risk acceptance is that it does not acknowledge that certain risks are simply unacceptable.

Another model, employed by the Norwegian oil industry Oljeindustriens Landsforening (OLF) is based on 'Risk Acceptance Criteria'. This approach does establish limits of acceptability. It is notably easy to use but, in our view, quickly overtaxed if used uncritically to separate acceptable from unacceptable risks. Among the limitations of this approach are: 1) it deals solely with mortality, ignoring sub-acute impacts, which are significant to harvesters; 2) the melding of the separate variables of percent mortality and anticipated recovery time into environmental damage categories reduces the problem to a manageable simplicity, but at the cost of limiting the meaningful interpretation of those categories; 3) the method rests on the ecologically simplistic notion that stocks predictably rebound to their previous levels after disturbance after some time, ignoring much evidence, particularly with respect to fisheries stocks, that such a benign return to equilibrium is not assured; and 4) the notion that an acceptable frequency limit can be defined, arbitrarily, as 20 times the recovery period is problematic. Decisions about risk are ultimately about social values. We do not assume that residents of the north will deem acceptable what the Norwegian Oil Industry deems acceptable.

One way the above two ideas (i.e. ALARP and risk acceptance thresholds) could work together is summarized in a paper prepared for the National Commission on the Macondo Spill:

> "The tolerable risk (TR) framework, first developed in the United Kingdom, has provided a basis for risk assessment in many agencies worldwide. The TR framework conceptually breaks risk into three categories – acceptable, unacceptable, and tolerable – separated by numerical boundaries. Under the TR framework, unacceptable risks are not allowed under any circumstances… Acceptable risks are considered to have been reduced to levels that are below concern and require no further reductions… [A]ll risks within the tolerable region must be reduced to levels "as low as reasonably practicable" (ALARP)… The goal of risk management is to push risks from the unacceptable, through the tolerable, and into the broadly acceptable region using specific ALARP considerations."[232]

The advantage of the Tolerable Risk Framework over ALARP as interpreted by CAPP is that it recognizes that some risks are unacceptable. The advantage of such a framework over the OLF Risk Acceptance Criteria is that it recognizes that risks deemed tolerable by virtue of falling below a limit should nonetheless still be reduced to levels "as low as reasonably possible" (ALARP).

The Tolerable Risk Framework does not address the value-laden question of what level of risk is acceptable and what is tolerable or the social question of how these matters are decided. The boundaries between the acceptable, tolerable and unacceptable may be defined numerically or categorically.

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[231] Standing Committee on Natural Resources, May 13, 2010, testimony of Mr. David Pryce, Canadian Association of Petroleum Producers, page 11.

[232] Risk Management Practices, 2011.

7.3 Examples of Unacceptable and Tolerable Risks

WWF-Canada has some preliminary thoughts on what risks are unacceptable and what risks are tolerable in Arctic offshore petroleum development. These examples are not intended to provide a comprehensive inventory of unacceptable activities; much less to draw hard lines between unacceptable and tolerable risks. They are provided simply in order to illustrate that a valid risk framework must define the boundaries of unacceptable risks and the scope of tolerable risks.

With respect to the risks of releasing oil into the environment:

- A project or activity that could result in a blowout that continues through the off-season (i.e. a multi-year blowout) falls into the 'unacceptable' category. Therefore, drilling should only be approved if such an occurrence is very, very unlikely. As explained in previous sections, given the chances of a blowout are not insignificant and given that same-well intervention techniques are, under numerous scenarios, either not available or not effective, the NEB should maintain the SSRW capability requirement for all offshore drilling in Arctic waters.

- A project or activity that could result in a prolonged within-season blowout is also unacceptable. As explained in previous sections, such a blowout could spill millions of gallons of oil into the environment, very little of which would be recovered, and inflict enormous damage on the ocean environment (*cf* Macondo). Therefore, drilling should only be approved if such occurrences are very unlikely.

Projects or activities that risk the release of large volumes of oil into the environment are unacceptable because the potential impacts to Arctic ecosystems and people are widespread, severe and potentially enduring. A project that could disrupt the cultural transmission of fishing or hunting practices for many years or interfere with Aboriginal rights may be deemed to carry an unacceptable level of risk.

- A project or activity could be deemed 'tolerable' with respect to oil releases if it could result in at most a low volume oil spill. The petroleum industry will have to demonstrate it has the capacity to rapidly contain blowouts and recover spills in order to establish that the risks of offshore exploration and development can fall within the 'tolerable' category.

In addition to our concern with the risks of oil releases, WWF-Canada is preoccupied by the risks of other impacts of petroleum development and industrial activity on the economic, ecological and cultural values of specific Arctic areas.

- A project or activity that presents a risk to a crucially important economic resource in a particular area may be deemed unacceptable. The exclusion of drilling activity in Bristol Bay in order to protect commercial fisheries is an example of this.

- A project or activity that presents a risk to a particularly sensitive area may be deemed unacceptable. The recent decision not to proceed with an environmental impact assessment, which would have been a precursor to petroleum development in the seas surrounding the Lofoten archipelago is an example. A project or activity that threatens critical habitat for marine species (e.g. important calving or feeding areas), or an area of particularly rich primary productivity (e.g. estuaries) could be deemed unacceptable.

- A project or activity that presents a risk to Aboriginal traditional use of a particular area could be deemed unacceptable.
- A project or activity that does not present too great a risk to the economic, ecological and cultural values of specific areas could be deemed tolerable.

We recognize that the delineation of areas to be excluded from development and the offshore leasing process lies outside the mandate of the NEB. However, we note that the "[s]tate of knowledge on the Arctic offshore, including the physical environment, biological environment and geosciences" is one aspect of "drilling safely while protecting the environment" in the Board's scope for this review.[233] Spatially explicit information, including existing designations of Marine Protected Areas, Environmentally and Biologically Sensitive Areas, and Particularly Sensitive Sea Areas may help to guide decisions as to whether the risks associated with projects and activities are tolerable or unacceptable in particular areas.

[233] NEB Scope of Arctic Offshore Review, 2010.

8 FINANCIAL RESPONSIBILITY AND LIABILITY

In our November submission, we briefly noted:

- BOEMRE's estimate that the costs from the Macondo blowout could be about $16.3 billion, although recent media reports put the figure as high as $40 billion.
- However, financial responsibility sought in the past in Canada was more than an order of magnitude less – about $350 million by the East coast offshore petroleum boards, and about $1 billion off the Arctic coast by the NEB.

Given the fundamental importance of the 'polluter pays' principle and the need to ensure that appropriate incentives are in place to reduce offshore drilling risk, the following provides detailed submissions regarding the liability regime, proof of financial responsibility, and the need to account for the cost of harm to natural resources specifically.[234] These are fundamental issues because they speak to: a) the adequacy and availability of offshore industry funds to pay for post-spill response clean up and associated damages, including potentially massive environmental damages; and, b) the financial incentive structures established by the liability regime, which directly impact the behaviour of the offshore industry.

8.1 Macondo

8.1.1 Cost estimates from Macondo spill

By way of background, it is helpful to review how these issues are playing out in the context of the recent spill in the Gulf of Mexico. The extent of damage remains unknown and will be impossible to fully calculate and compensate, especially as long-term effects continue into the future. Notwithstanding the uncertainty, assessments of the impacts and legally-compensable damages have been and continue to be undertaken.

- In November 2010, BP estimated that its total costs from the *Deepwater Horizon* spill, including the clean-up, penalties and damages, will total nearly $40 billion.[235] A report submitted to the National Commission by a non-profit group of expert ecological economists (Resources for the Future) estimated total natural resource damages and economic damages to private parties at anywhere between $105 billion and $239 billion dollars (based on scaling up damages resulting from the *Exxon Valdez* spill).[236]
- Significantly, the National Commission report does not attempt to calculate an updated tabulation of the total costs from the spill. Indeed, it critiques attempted calculations given the enormous uncertainty regarding baseline ecological conditions prior to the spill.[237] But as regards economic losses, the National Commission report does state that: "The costs

[234] Arctic Council Offshore Oil and Gas Guidelines, 2009, page 6. Note the inclusion of the polluter pays principle in section 1.3 of the Arctic Council's guidelines.

[235] Staff Working Paper No. 10, Nov 2011, page 1.

[236] Understanding the Costs and Benefits, Krupnick/Resources for the Future, Jan 2011 page 28.

[237] National Commission report, Jan 2011, page 185.

from this one industrial accident are not yet fully counted, but it is already clear that the impacts on the region's natural systems and people were enormous, and that economic losses total tens of billions of dollars."[238] As regards environmental (natural resource) damages, it states: "Estimates of the cost of Gulf restoration, including but not limited to the Mississippi Delta, vary widely, but according to testimony before the Commission, full restoration of the Gulf will require $15 billion to $20 billion: a minimum of $500 million annually for 30 years."[239] Thus, it would appear that BP's aforementioned estimate of $40 billion in total costs may be on the low side.

- It is not clear whether BP, in estimating the total costs, included the anticipated payout on the hundreds of tort cases that have been filed as a result of the spill. Among them is a civil suit against BP and eight other companies brought by the US Justice Department for violations of the *Clean Water Act*, seeking civil penalties, cleanup costs, and damages, including natural resource damages.[240] The maximum civil penalties under the *Clean Water Act* could range from $4.5 billion to $21 billion, depending upon findings of negligence and the calculation of barrels discharged…"[241] In addition, the US Justice Department will likely prosecute criminal violations of environmental protection statutes.[242] According to the former Chief of the US Justice Department's Environmental Crimes Section, "BP is likely to pursue a global settlement that resolves both criminal and civil penalties for the Gulf oil spill (along with restitution and natural resource damage claims)…BP could negotiate a payment schedule that would make even multi-billion fines manageable."[243]

By way of context, in the aftermath of the *Exxon Valdez* tanker spill, "Exxon spent approximately $2.1 billion in cleanup costs, and, pursuant to a settlement with the United States and Alaska, agreed to pay a criminal fine of $150 million ($125 million of which was forgiven in light of its cleanup efforts), $100 million in criminal restitution, and $900 million to settle civil claims, subject to reopener provisions allowing for an additional $100 million."[244] If the *Exxon Valdez* experience serves as a guide, it is unlikely that the total costs and assessed damages from the Gulf disaster will be known until the 2020s or even the 2030s.

8.1.2 Liability cap and financial requirements – the US debate

The lesson to be drawn from the US experience is clear: the financial capacity of offshore operators (and their contractors) to pay for worst-case scenario damage situations is of central importance. As noted in National Commission Staff Paper No. 10:

> "The fact that BP is able to provide full monetary compensation for damages that it causes is no more than a fortuity, not a product of regulatory design. If a company with less

[238] National Commission report, Jan 2011, page vi.

[239] National Commission report, Jan 2011, page 210.

[240] After the Spill is Gone, Uhlmann, Jan 2011 page 5.

[241] National Commission report, Jan 2011, page 211.

[242] After the Spill is Gone, Uhlmann, Jan 2011, page 7.

[243] After the Spill is Gone, Uhlmann, Jan 2011, page 31.

[244] After the Spill is Gone, Uhlmann, Jan 2011, page 31.

> financial means had caused the spill, the company would likely have declared bankruptcy long before paying anything close to the damages caused."[245]

The National Commission Staff Paper No. 10 affirmed that the current absolute liability cap "provides little incentive for improving safety practices to decrease the likelihood of major spills, and it limits the ability of those of who suffer damages to receive full compensation."[246] It goes on to state: "If liability and financial responsibility limits are not set at a level that will ensure payment of damages for all spills, then another source of funding will be required to fully compensate victims of a spill. The federal government could pay additional compensation costs, but this approach requires the taxpayer to foot the bill, essentially subsidizing the drilling activity."[247] Thus, inextricably linked to the issue of the polluter's ability (and obligation) to pay the full costs of a worst case spill is the behavioural impact of liability exposure.

To set the stage for a comparative discussion, it is instructive to draw upon the National Commission Report's summary of the basic architecture of financial capability requirements and liability caps in the US. As regards the liability cap under the US *Oil Pollution Act* (OPA): "[R]esponsible parties…are strictly liable for removal costs and certain damages resulting from a spill. Compensable damages are defined in the Act. Removal costs themselves are unlimited, but there is a cap on liability for damages: for offshore facilities, $75 million. The cap does not apply in cases of gross negligence, violation of an applicable regulation, or acts of war, and does not limit the amount of civil or criminal fines that might be imposed for violations of federal law, such as the *Clean Water Act*, nor does it limit damages under state law."[248]

As regards financial requirements, the OPA "also requires responsible parties to 'establish and maintain evidence of financial responsibility,' generally based on a 'worst-case discharge' estimate. In the case of offshore facilities, necessary financial responsibility ranges from $35 million to $150 million. The financial responsibility requirement provides a direct link between the *Oil Pollution Act* and insurance…"[249]

The interconnected issues of financial requirements and liability cap amounts have been debated in the US, notably in the context of various congressional bills that have been introduced to do some or all of the following: i) eliminate or significantly raise the liability cap; ii) raise financial responsibility limits or require their review by the Secretary of the Interior; iii) require participation in a mutual liability pool; iv) increase the amount of available per incident funding in the Oil Spill Liability Trust Fund.[250]

While none of these proposals has been enacted into law, it is significant that they reflect the two broad lines of critique outlined by the National Commission Report, both of which are equally applicable in Canada:

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[245] Staff Working Paper No. 10, Nov 2011, page 1.

[246] Staff Working Paper No. 10, Nov 2011, page 1.

[247] Staff Working Paper No. 10, Nov 2011, page10.

[248] National Commission report, Jan 2011, page 245.

[249] National Commission report, Jan 2011, page 283.

[250] See Staff Working Paper No. 10, Nov 2011, page 4, including footnotes 22 to 25 for a complete list of the legislative proposals.

> "The amount of potential damage caused by a major spill clearly exceeds the existing caps, and one cannot fairly assume that the responsible party causing a future spill will, like BP, have sufficient resources to fully compensate for that damage. Nor should the spill's victims or federal taxpayers have to pay the bill for industry's shortcomings. Increasing liability limits would also serve as a powerful incentive for companies to pay closer attention to safety, including investing more in technology that promotes safer operations."[251]

Not only are these critiques valid in Canada, it is also significant that the competing public policy concerns that militate against any proposals to fulfill this recommendation in the US are less applicable in the Canadian Arctic context. The main fears are that independent oil companies will be driven out of the Gulf of Mexico market (due to the unavailability of affordable insurance), thereby reducing overall competition, reducing production (from smaller, "end-of-life" oil fields), and causing significant job losses.[252] Without the vested interests of an active offshore industry and attendant jobs/production volume concerns in Canada's offshore Arctic, the downside of a higher liability cap and financial capability requirements are much less pronounced. In addition, if offshore development is to occur in Canada's Arctic, there is no reason to believe that mutual insurance pooling could not work, or that smaller and larger operators could not engage in joint ventures.[253]

8.2 Montara

The Montara Commission of Inquiry noted a number of similar concerns about financial responsibility and liability.

- First, the Commission criticized the regulator, the Northern Territories Department of Resources (NT DoR) for not adequately ensuring the operator (PTTEPAA) had appropriate insurance in place, noting: "The expenses and liabilities arising from a blowout could quite foreseeably exceed the financial capacity of an operator to meet them. Many people and organisations could be affected by such an event over a long period of time. The Inquiry therefore took an interest in what steps the NT DoR had taken, pursuant to s. 571 of the OPGGS Act, to ensure that PTTEPAA and other operators had appropriate insurance to cover expenses and liabilities. Once again, the evidence that emerged suggested that the NT DoR was content to rely on operators in order to ensure that the public was adequately protected from potential risks. Basic questioning, probing or testing (that could easily have taken place) was not considered necessary or appropriate."[254]
- Second, the Commission also noted that government had to negotiate an arrangement for funding of scientific monitoring with the operator ('scientific monitoring' means all monitoring other than for direct operational relevance to spill response, such as for short- and long-term damage assessments including recovery), which resulted in "unacceptable"

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[251] National Commission report, Jan 2011, pages 245-246.

[252] National Commission report, Jan 2011, page 285; Staff Working Paper No. 10, Nov 2011, pages 7-8.

[253] National Commission report, Jan 2011, page 285.

[254] Montara Commission report, Jun 2010, page 204 paragraph 4.157.

delays.[255] The Commission therefore supported "the removal of the distinction between the funding of Operational and Scientific Monitoring," and explained that "implementation of the Inquiry's recommendations in relation to the regulatory framework would … provide a sufficient basis for compelling an owner/operator to bear the costs of Scientific Monitoring in Commonwealth waters."[256]

- Third, the Commission noted the importance of analyzing worst-case scenarios, and included among its recommendations to government that pre-drilling assessments should include a risk assessment of the worst-case blowout scenario."[257]

In conclusion, the Montara Commission recommended to government that the Australian "National Plan should specify that the cost of responding to an oil spill, or other damage to the offshore marine environment, will be totally met by the owner/operator. This would be consistent with the Inquiry's recommendation for legislative changes to the regulatory framework concerning owner/operators meeting the cost of monitoring and remediation of environmental damage."[258]

8.3 Operator Liability is Inappropriately Limited by Low Caps

To address inadequate safety incentives and damages compensation, the National Commission Report recommended that "Congress should significantly increase the liability cap and financial responsibility requirements for offshore facilities".[259] Likewise, the Montara Commission report recommended that a polluter-pay-based financial liability and responsibility regime be established in relevant legislation, that the obligation of companies to meet the full costs of an incident be made a condition of approvals, and that suitable arrangements (insurance or otherwise) need to be in place to ensure that companies have that capacity.

WWF-Canada submits that existing absolute liability limits that apply in Canada's offshore Arctic are too low, and that this cap should simply be abolished. With Macondo costs estimated at a minimum of $40 billion, the $40 *million* absolute liability cap in Canada's Arctic offshore is clearly inadequate and does not serve the polluter-pays objectives of compensation and risk-

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[255] Montara Commission report, Jun 2010, page 289 paragraph 6.31, page 291 finding 83.

[256] Montara Commission report, Jun 2010, page 293 paragraph 6.46, page 314 paragraph 6.113.

[257] Montara Commission report, Jun 2010, page 152 recommendation 12.

[258] Montara Commission report, Jun 2010, page 296 recommendation 92, and pages 316-317 recommendations 95 and 96. In particular, note page 315 finding 90: "The environmental protection regime for Commonwealth waters should include the following elements to embody the polluter pays principle: a) the Government should have the power to require the companies involved in an incident – both prospectively and already approved projects – to undertake Scientific Monitoring of the environmental impacts of an incident, and to undertake actions to remediate any damage resulting from the incident to a required standard; b) the costs of undertaking Scientific Monitoring or of remediating the damage arising from a significant incident should be fully borne by the companies involved, whether the monitoring or remediation is undertaken by the company or by Commonwealth, state or territory agencies or other parties. Further it should be the environmental regulatory agencies that determine the nature of Scientific Monitoring arrangements and remediation required, not the company involved; c) regulatory authorities should be satisfied that companies have adequate insurance arrangements in place to allow them to meet their obligations; and, d) there should be provision for the payment of penalties for pollution on a no fault basis, which should be similar in scale to that which would be applicable in state regimes."

[259] National Commission report, Jan 2011, page 284.

reduction.[260] As the US environmental economic think-tank, Resources for the Future, puts it: "...to the extent external costs have not been internalized by responsible parties, firms do not have adequate incentives to take the socially desirable level of care in preventing future spills or other harmful effects of their drilling operations."[261]

8.4 Clarify Compensation for Environmental Damage and an Assessment Process

Beyond the problem of the absolute liability cap, a critical analysis of the main liability provisions reveals a lack of legislative clarity as regards the types of damages that can be claimed, particularly in terms of environmental damages. WWF-Canada submits that a risk-reducing and environmentally protective offshore regulatory regime must compensate: i) the replacement and/or restoration of any lost or compromised ecological resources; ii) the lost value of those ecological resources; and, iii) any costs incurred in assessing the harm to such ecological resources. Although the identification and quantification of environmental damages is a complex endeavour, it is a fundamental component of the US offshore oil regulatory regime.[262]

Canada's current liability regime for a spill resulting from offshore Arctic drilling may be summarized as follows:

1. if there is fault or negligence, the operator is liable for everything that a court can award (standard liability);[263]
2. the operator is liable for the costs of "all reasonable measures in relation to the spill" again without limitation (absolute liability);[264]
3. in the Inuvialuit Settlement Region, the operator is liable for all actual wildlife harvest loss or future wildlife harvest loss under the *Inuvialuit Final Agreement* (IFA), again without limitation (absolute liability);[265] and,
4. the operator is otherwise liable for "all actual loss or damage", but only up to a maximum of $40 million (capped absolute liability).[266]

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[260] This liability cap is established pursuant to s.26(1)(a) and 26(2)(a) of COGOA and the *Oil and Gas Spills and Debris Liability Regulation*, SOR/87-331.

[261] Understanding the Costs and Benefits, Kropnick/Resources for the Future, Jan 2011, page 38.

[262] National Commission report, Jan 2011, at p.183: "Identifying and quantifying damages, particularly where complex ecosystems are involved, present enormous challenges. Developing sound sampling protocols that cover adequate time scales, teasing out the effects of other environmental disturbances, and scaling the damages to the appropriate restoration projects often takes considerable time. A typical damage assessment can take years."

[263] Of course, as the NEB Backgrounder correctly states: "Companies drilling in the Canadian Arctic are liable for the loss or damage that they cause in accordance with the general laws of Canada." But initiating a lawsuit and establishing a negligence claim against one of the world's leading oil companies is a significant barrier to damage recovery for third parties, indeed, even for governments. This is why the provisions for absolute liability are so important, and why a cap on absolute liability provisions is so relevant.

[264] COGOA s. 25(7).

[265] *Inuvialuit Final Agreement*, s. 13.

[266] COGOA s. 26. The term "all actual loss or damage" is defined in s. 24(3) as including "loss of income, including future income, and, with respect to any aboriginal peoples of Canada, includes loss of hunting, fishing and gathering opportunities".

Although these provisions arguably allow for claims against an operator to ensure it pays for not only economic and harvesting losses, but also for the loss and restoration of other environmental damages, they leave a lot to be desired in terms of clarity. For example, does “all reasonable measures in relation to the spill” in (2) and/or “all actual loss or damage” in (4) include costs for ecological restoration, remediation and cleanup that might take many years to complete? In addition, there is no specific process for calculating environmental damages.

In contrast, under the US *Oil Pollution Act*, there is a well-established and sophisticated process for evaluating natural resource damages from an oil spill and for assigning responsibility to responsible parties, including the costs of replacing or restoring damaged resources.[267] In assessing the damages that may result from an oil spill, a process is undertaken whereby Trustees (governments in charge of the resources) complete pre-assessment, restoration planning and recovery plan phases.[268] The entire process is designed to encourage collaboration with the responsible parties, so as to resolve liability issues and avoid cumbersome and costly litigation. Thus, Canada lags behind the US in terms of providing an explicit, comprehensive and principled statutory approach to account for environmental damage claims.

WWF-Canada therefore submits that Canada’s liability regime for the North should be amended as follows:

- clarify that operator’s liability includes the lost values of environmental resources and funds to pay for the assessment of damages to them and for their replacement and/or restoration; and
- include a process for assessing liability for environmental damages, akin to the US process.

8.5 Financial Responsibility Must Cover all Potential Costs of a Worst Case Spill

The question of liability caps cannot be separated from the issue of ensuring an operator’s financial capacity to pay for the costs of a worst-case spill:

> “[I]t is unlikely that raising or eliminating the liability cap will have the desired effect of providing incentives for safe practices or ensuring full compensation for victims, unless demonstrated financial responsibility is required at levels commensurate with the cap. The debate... has focused primarily on increasing or eliminating the liability cap... discussion of financial responsibility requirements has been secondary. However, if the liability cap is increased without a corresponding increase in financial responsibility requirements, then a firm could meet its financial responsibility requirements and still go bankrupt before paying even a small fraction of the damage associated with a spill. The liability limit would, in effect, be irrelevant.”[269]

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[267] See Natural Resource Damage Assessment, Congressional Research Service, Sep 2010. The *Oil Pollution Act* defines “natural resource damages as “[d]amages for injury to, destruction of, loss of, or loss of use of, natural resources, including the reasonable costs of assessing the damage, which shall be recoverable by a United States trustee, a State trustee, and Indian tribe trustee, or a foreign trustee.” (33 U.S.C. ss. 2702(b)(2)(A). Natural resources are defined in the OPA as “land, fish, wildlife, biota, air, water, ground water, drinking water supplies, and other such resources...” (33 U.S.C. ss. 2701(20).

[268] Natural Resource Damage Assessment, Congressional Research Service, Sep, 2010. See also OPA Claimant’s Guide, Nov 2009.

[269] Staff Working Paper No. 10, Nov 2011, page 5.

In Canada's Arctic, two main issues arise: first, the level of financial capability required; and second, the applicable criteria in determining the appropriate level of financial capability.

As regards the issue of the amount, whether the financial requirement has been $350 million (Atlantic offshore boards) or $1 billion (Arctic coast),[270] WWF submits that this level of financial capability is manifestly inadequate in a post-Macondo era. Given that the actual cost to BP will be at least $40 billion and quite possibly several tens of billions more, the financial capability requirements previously imposed by the NEB appear to be at least an order of magnitude too small.

WWF submits that proof of an operator's ability to pay for <u>all costs and damages, both immediate and long term</u>, <u>associated with a worst case spill</u> is essential if further offshore drilling in Canada's Arctic is to be contemplated. Mere proof of a company's assets is no guarantee that governments and spill victims will be able to access those assets in the case of bankruptcy. Even where recovery of some costs is possible, this could be significantly delayed during lengthy bankruptcy proceedings. Such situations must be avoided.

Turning to the second issue of the applicable criteria in determining the appropriate level of financial capability, COGOA does not specify or describe what the Board must consider in establishing the financial responsibility requirements.[271] WWF is not aware of any regulations or guidelines that have been established to provide transparent, comprehensive and explicit criteria for the NEB to determine the financial capability of offshore operators.[272]

However, WWF recognizes that NEB decisions regarding financial requirements for offshore drilling in the Inuvialuit Settlement Region (ISR) must be informed by the review process undertaken by the Environmental Impact Review Board (EIRB).[273] In support of the wildlife and habitat protection, restoration and compensation provisions under s. 13 of the IFA[274], the EIRB's review process requires consideration of a worst case scenario (and potential liability in relation to this scenario) as part of any recommendation to allow a development to proceed.[275] Thus, in the western portion of Canada's Arctic, the NEB's financial requirement analysis is informed by specific reference to Inuvialuit concerns.

[270] Standing Committee on Natural Resources, June 15, 2010, at p. 10, testimony of Mr. Eric Landry (Director, Frontier Lands Management Division, Petroleum Resources Branch, Department of Natural Resources); Standing Committee on Natural Resources, June 15, 2010, at p. 10, testimony of Ms. Mimi Fortier (Director General, Northern Oil and Gas, Department of Indian Affairs and Northern Development).

[271] See COGOA s. 5(3), (4), and s. 27(1). Note also that the NEB Backgrounder – Financial Responsibility and Liability states that the NEB "sets the requirements on a case-by-case basis and looks at relevant matters in setting the amount of financial responsibility".

[272] WWF-Canada understands that two existing NEB documents may contain internal criteria for financial responsibility decisions: 1) "Guidelines Concerning Financial Responsibility"; and, 2) "Guidance Notes for the Canada Oil and Gas Drilling Regulations". WWF has made inquiries regarding access to these documents, and according to Sarah Kiley, NEB Communications Officer, in an email dated March 28, 2011; "Currently, we are working on producing guidelines for the development of safety plans...However, the *Guidelines Concerning Financial Responsibility* have not yet been re-drafted to reflect the new regulations. The old version has been removed from the website as they are no longer relevant. At this point, we do not know when these guidelines will be replaced."

[273] *EIRB Operating Procedures*, s. 5.14.

[274] *Inuvialuit Final Agreement*, ss.13 (13) and (14).

[275] *EIRB Operating Procedures*, s. 5.14.

By way of comparison, the two Atlantic offshore petroleum Boards have issued joint guidelines regarding requirements for financial responsibility.[276] These guidelines outline basic objectives which the operator's proof of financial responsibility documentation are to achieve, including "restoring and preserving the natural environment, including the sea bed, while the work or activity is going on and after it is completed and abandoned".[277] Although these guidelines do not establish specific criteria that must be considered when establishing financial requirements, and do not require a worst case scenario approach, they do at least incorporate environmental damage repair as part of an explicit rationale for demonstrating financial capacity.

Given the uncertainty surrounding the extent of clean up costs and the broad range of environmental/economic damages that could result from an Arctic offshore spill, and given the direct requirement for the EIRB review process analyses to be based on worst case liability scenarios in the Inuvialuit Settlement Region, WWF submits that the NEB should clearly set out the bases upon which it determines the appropriate level of an operator's financial capability. WWF recommends that specific, enumerated criteria be articulated pursuant to a guideline or regulation, and that the rationale underlying any particular determination be explicitly accounted for and made publicly available.

Such criteria should take a worst case scenario as the appropriate starting point, should consider the actual costs of recent spills around the world, and should include geological and environmental considerations, the offshore operator's experience and expertise, and any applicable risk management plans.[278] The following criteria, adapted from a bill introduced in the US Senate, would also be appropriately considered: (i) the water depth of the lease; (ii) the minimum projected well depth of the lease; (iii) the proximity of the lease to oil and gas emergency response equipment and infrastructure; (iv) the likelihood of the offshore facility covered by the lease to encounter broken sea ice; (v) the record and historical number of regulatory violations of the leaseholder;(vi) the estimated hydrocarbon reserves of the lease; (vii) the estimated well pressure; (viii) the estimated economic value of non-energy coastal resources that may be impacted by a worst-case spill; (xi) the estimated environmental use and environmental passive use values of the marine and coastal areas; and, (x) any relevant equipment/technological considerations (i.e. whether the offshore facility covered by the lease employs a subsea or surface blowout preventer stack)."[279]

8.6 Preliminary Conclusions

The current design of Canada's Arctic offshore liability rules leaves governments, taxpayers, communities and the environment vulnerable in the event of a significant spill. These rules are important not only because of how they shape and limit any claims for compensation (post-spill), but also because of how they create incentives for offshore companies to avoid excessively risky activities (pre-spill). WWF submits that the polluter-pays principle should receive full application in the Arctic offshore, with a view to enhancing incentives for industry to avoid spills

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[276] *Canada-Newfoundland Guidelines Respecting Financial Responsibility,* 2010.

[277] *Canada-Newfoundland Guidelines Respecting Financial Responsibility,* 2010, s. 3(b).

[278] Staff Working Paper No. 10, Nov 2011, page 9-10.

[279] *Oil Spill Compensation Act of 2010*, S. 3542, 111th Cong. (2010), §301(e).

and to ensure funds are available for full response, cleanup, restoration and compensation should a spill occur.

As such, WWF concludes that the $40 million liability cap should be abolished and responsibility requirements significantly increased, commensurate with the entire potential costs of a worst case spill. Regarding the determination of appropriate financial capability amounts, WWF suggests that the NEB should identify the risk factors that will guide its discretion. Finally, regarding compensation for environmental damages, WWF suggests that the NEB should recommend to the federal government that COGOA be clarified so as to explicitly confirm reference to the availability of environmental damages claims, and include a process (similar to the natural resource damage process in the US) for assessing them.

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Given the NEB's website already links to certain reports, such as the National Commission report (Jan 2011) on the Macondo blowout and the Montara Commission report (June 2010) on the Montara blowout,[280] we have not submitted these lengthy documents (please advise if you would like us to). We have also not submitted documents already on the NEB's website. We are submitting all other references both electronically and via paper copies, except for the three books (Blowout and Well Control Handbook, Grace, 2003 ; Disaster on the Horizon, Cavnar, Oct 2010; and Offshore Blowouts, Holand, 1997) for which we can only submit hard-copy excerpts.

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[280] A link to these reports is provided at http://www.neb-one.gc.ca/clf-nsi/rthnb/pplctnsbfrthnb/rctcffshrdrllngrvw/dcmnt-eng.html#s3.

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