Safety Indicators for Offshore Drilling

A working paper for the CSB inquiry into the Macondo blowout

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Introduction

Considerable progress has been made in recent years towards the development of major hazard risk indicators, in particular process safety indicators. So far, however, this effort has not been focussed on the risks of blowout, especially offshore. This paper addresses the need for indicators specifically related to the risk of blowout. It begins with a discussion of the development of process safety indicators.

Process safety indicators

One of main lessons coming out of the Texas City disaster was the need for a separate focus on process safety, as opposed to personal safety. This means, in particular, the need to develop process safety indicators. The Baker report recommended that BP adopt a composite process safety indicator consisting of the number of fires, explosions, loss of containment events and process-related injuries. The US Centre for Chemical Process Safety subsequently recommended that the chemical industry as a whole adopt such a measure.

Where a site is experiencing numerous fires and loss of containment incidents, as Texas City was, such a measure is a useful indicator of how well process safety is being managed, in the sense that a reduction in the number of such incidents implies an improvement in process safety management. At some sites, however, the number of fires and loss of containment incidents will already be so low that such figures cannot be used to monitor changes in the effectiveness of process safety management. To make the point concretely, if there is one loss of containment event in one year but two in the next, it cannot be assumed that the safety management system has deteriorated. Although this is a doubling, or an increase of 100%, the numbers are too small to be statistically significant. The increase may simply a matter of chance. In contrast if the numbers went from 100 to 200, the same percentage increase, we would certainly want to infer that the situation had deteriorated.

Where the numbers are too low to be able to identify trends, an alternative approach to measuring process safety is needed. That approach is to identify the barriers or defences or controls that are supposed to be in place to prevent a major accident event, and to measure how well those controls are performing[1]. To give a simple example, if safety depends in part on pressure relief valves opening when required, then what is needed is some measure of how well they are functioning. Or a different kind of example: if one of the controls on which safety depends is a requirement that operators stay within pre-determined operating limits, then we need to measure the extent to which they are exceeding those limits.

Indicators of the first type – numbers of gas releases and fires - are sometimes called lagging indicators, while measures like deviations from safe operating limits are sometimes referred

[1] A useful statement if this approach can be found in , –" Developing process safety indicators: a step-by-step guide for chemical and major hazard industries," UK Health and Safety Executive, 2006

to as leading indicators. However the terminology is somewhat confusing and will not be adopted here[2].

The report of the US Chemical Safety board into the Texas City accident recommended to the American petroleum Institute (API) that it develop a set of process safety performance indicators to cover both situations.[3] API did just that and finally published its “Recommended Practice 754: Process Safety Performance Indicators for the Refining and Petrochemical Industries” in April 2010, coincidentally, the month of the Macondo accident.

API 754 defines a process safety pyramid, analogous to the familiar personal safety pyramid, or triangle, or iceberg. (Figure 1)

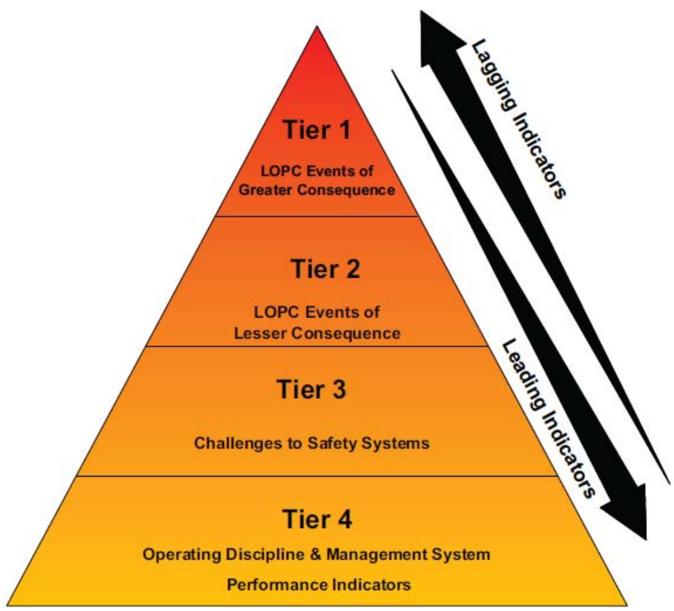

Figure 1: API 754 Process safety indicator pyramid

Simplifying somewhat, Tier 1 is defined as follows:

1. Any loss of primary containment (LOPC)[4], regardless of size, which has significant consequences such as a lost time injury or fire; or

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[2] Hopkins A, “Thinking About Process Safety Indicators,”, *Safety Science*, 47 (2009): 460–465

[3] P212

[4] The concept of *primary* containment creates some difficulties. Suppose a container is over-pressured and pressure relief valves lift, releasing flammable gas. But suppose further that this gas is contained via a secondary containment system and released to atmosphere through a flare, as combustion products only. Logically, this sequence of events amounts to a loss of primary containment of a flammable material, with containment and neutralisation by the secondary containment system. It appears that this is the view of the standard writers when they say “Tier 2 PSEs, even those that have been contained by secondary systems

2. Any loss of primary containment greater than a certain threshold size, even though there may be no consequences[5].

The threshold depends of the kind of material involved. For example, for a flammable gas, the threshold is 500 kgs.

Tier 2 is defined in similar terms, with threshold gas release being 50 kgs.

A Tier 3 event is one that “represents a challenge to the barrier system that progressed along the path to harm but is stopped short of a Tier 1 or Tier 2 LOPC”. For example,

-an excursion from safe operating limit
-test results outside acceptable limits
- a demand on a safety system, such as the lifting of a pressure relief valve.

Tier 4 refers to measures of the process safety management system itself, such as

-process hazard evaluations completed on time
-action items closed on time
-training completed on schedule
-procedures current and accurate
-work permit compliance

Where tier 1 or 2 events are occurring with sufficient frequency to be able to compute a rate, the focus must be at this level and the aim must be to drive the rate downwards. Where the number of loss of containment events is too small to be able to compute a meaningful rate, the focus shifts to tiers 3 and 4. This will often be the situation at specific sites. But for some large sites, such as the Texas City refinery, and for large companies and whole industries, the number of loss of containment events will be large enough to keep the focus at this level.

BP headed the advice of the Baker panel. In the years following the Texas City accident it developed various process safety indicators, central among them being loss of containment events. The data were carefully analysed at corporate headquarters and presented in a uniform manner that allowed comparisons across the company[6]. In 2010 BP adopted the API definitions described above, with an emphasis on tier 1 and tier 2 loss of containment events[7].

The lack of relevance of the loss of containment indicator to drilling

API 754 is applicable to any industry where a loss of containment has the potential to cause serious harm[8]. It specifically applies to refining and petrochemicals industries. The standard

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indicate barriers system weaknesses that may be potential precursors of future, more significant. incidents.”(para 6.1). However, some commentators argue that the scenario just described is not an LOPC.
[5] There are several other ambiguities about these definitions that will not be addressed here.
[6] “HSE and Operations Integrity Reports”. BP’s so called Orange books.
[7] I shall use LOPC and LOC interchangeably in this discussion.
[8] Section 1.2

is potentially relevant to upstream oil and gas production, but drilling is a different matter. I shall argue here that loss of containment is *not* a significant indicator of how well the risks of blowout are being managed.

Gas can be and is released from wells during the drilling process and can reach dangerous levels on a rig. Speaking about the gas alerts on the Deepwater Horizon, one witness said:

> "we had gotten them so frequently that I had actually become somewhat immune to them. I'd get to the point where I didn't even hear them anymore because we were getting gas back continuously. It was a constant fight. When the level reached 200, that's the cut-off for all chipping, welding and grinding and other outside hot work. That's when I start concerning myself with gas levels…. (That's when) I don't need to be making sparks anywhere, of any kind. So at that point is when I really start paying attention to gas levels".[9]

It is apparent from this account that gas releases during well drilling operations were not normally regarded as significant. Nor were they treated as reportable LOC events. The gas referred to is largely "drill gas" or "vent gas" that is routinely generated in some wells as drilling progresses, especially when drilling through shale. It is normally vented to atmosphere[10]. Most importantly, it is not indicative of a well kick and is not a precursor to blowout. Hence, even if such releases were treated as reportable LOC events, reducing the number of such events would not necessarily reduce the risk of blowout.

This is not to say that vent gas should not be treated seriously. But the API standard is of no use in this context. It depends on the ability to estimate the *weight* of gas released, and it is unlikely that realistic estimates could be made of the weight of vent gas released. What could however be measured are occasions on which vent gas reached dangerous *concentrations.* This would be an entirely different indicator. It is desirable such an indicator be developed. MMS was aware of the problem of vent gas on the Deepwater Horizon and had requested that the drilling "proceed with caution". A relevant indicator would greatly assist with the management of this hazard.

Oil spills

Another indicator that is widely used in offshore operations is number and volume of oil spills. Some CSB interviewees suggested that this was an indicator of process safety. Indeed the BP report to the NAE states that "oil spill data is a process safety metric"[11]. However oil is not volatile and, in particular, it is not volatile enough to count as an LOC under the API standard. Moreover, oil spills tend to be from hydraulic hoses. According to one well team leader interviewed, "there are thousands of hydraulic hoses everywhere … and that would be

[9] Williams, DWI July 23, p8,9
[10] I am indebted to David Pritchard for this account.
[11] P 41

our biggest nemesis, where a hydraulic hose would burst and you would leak some hydraulic fluid onto the deck"[12]. He noted that drilling operations distinguished between leaks and spills and both were tracked. If a release was contained on deck it was a leak; if it reached the ocean, it became a spill[13]. This distinction makes perfect sense from an environment protection point of view, but not from a process safety point of view. Oil spills are environmental events, worth counting and driving down in order to reduce pollution, but they are not the precursors to a major accident event.

Kicks

If blowouts were occurring sufficiently often to be able talk sensibly about a rate that could be driven downwards, then the blowout rate itself would be an appropriate indicator of blowout risk. However, according to an MMS study, there were 39 blowouts in the GoM in a 15 year period from 1992 to 2006, that is, an average of between 2 and 3 per year. This is too small a number to be useful.

Consider therefore the immediate precursor to a blowout, namely a well kick or well control incident (these terms are used interchangeably). These are more numerous and it is widely recognised that reducing the number of kicks reduces the risk of blowout. For any one well, the number of kicks may be too small to serve as a useful indicator, but number per company per year is something companies could usefully compute and seek to drive downwards. Number of kicks per year across a whole region, such as the Gulf of Mexico, is an indicator that should be of vital interest to the regulator, since it is a measure of the risk to which, in a sense, the regulator is exposed.

One consideration in introducing new indicators is the ease with which they can be manipulated. This is especially true if they are indicators that matter, for example, if they influence remuneration. Where measures matter like this, the first response is to try to manage the measure. The simplest strategy is to discourage reporting, but there are also clever classification games that can be played to minimise the figures. Lost time injury statistics, for example, suffer from this kind of manipulation[14]. Even LOCs can be manipulated. The weight of a release must be calculated from pressure, duration and size of hole, all of which must be estimated, which leaves plenty of room for manipulation of the data. A kick however is a relatively unambiguous event which is not easily suppressed[15]. The number of kicks is therefore a reasonably robust indicator, from this point of view.

It is sometimes objected that wells differ in complexity and hence propensity to kick, and that any indicator based simply on number of kicks would therefore be misleading. This may be so. But there are ways in which levels of complexity can be taken into account so that valid comparisons to be made. One possibility is to make use of the Dodson Mechanical Risk

[12] Guide, CSB,Nov 3, p24
[13] Guide CSB Nov 3, p24
[14] Hopkins A, *Failure to Learn: The BP Texas City Refinery Disaster* (CCH Sydney 2008), p85-6
[15] CSB Nov3Spraghe, p109

Index (MRI). The MRI divides wells into five complexity levels, based on water depth, well depth, number of casing strings and salt penetration. As complexity level increases, so too does number of well bore instability events, including kicks[16]. This would need to be taken into account as a way of refining the indicator.

Regulatory reporting requirements

Some jurisdictions already require that operators report kicks, among other things, to the offshore regulator. Here are the main reporting requirements of three different regimes - Norway, Australia and the US:

Norway[17].

- Non-ignited hydrocarbon leaks
- Ignited hydrocarbon leaks
- Well kicks/loss of well control
- Fire/explosion in other areas, flammable liquids
- Vessel on collision course
- Drifting object
- Collision with field-related vessel/installation/shuttle tanker
- Structural damage to platform/stability/anchoring/positioning failure
- Leaking from subsea production
- systems/pipelines/risers/flowlines/loading buoys/loading hoses
- Damage to subsea production equipment/pipeline systems/diving equipment caused by fishing gear

Australia[18]

- death or serious injury
- dangerous occurrences that could have caused death or serious injury
- hydrocarbon releases, well kicks
- fires or explosions
- safety-critical equipment damage
- implementation of Emergency Response Plan
- marine vessel and facility collisions

Hydrocarbon releases are singled out for special attention and the regulator computes a rate of gas release normalised by volume of production.

[16] Pritchard D & Lacy K, "Deepwater well complexity – the new domain", Working paper for Deepwater Horizon Study Group , January 2011, pp9, 15,17

[17] Petroleum Safety Authority, Trends in Risk Level. Summary Report 2009, Norwegian Continental Shelf.

[18] http://www.nopsa.gov.au/document/Charts%20-%20Quarterly%20Key%20Performance%20Indicators%20June%202011.pdf

US[19]

- deaths
- fires
- explosions
- blowouts
- serious injuries
- releases of hydrogen sulphide gas
- collisions
- structural damage
- Incidents involving cranes, personnel handling, or materials handling equipment
- damage to safety systems or safety equipment
- evacuations
- gas releases that initiate equipment or process shutdown

It is notable that the list for the US does not include *all* gas releases, or even all gas releases of more than a certain size, that is, it does not require the reporting of LOPCs as defined in API 754. Nor does it require that *kicks* be reported. In contrast, both the Norwegian and Australian regulators require that all hydrocarbon releases and all kicks be reported.

Response to kicks

There is another potential indicator of blowout risk that became apparent during the inquiries after the Macondo accident. Blowout prevention relies on drillers recognising kicks as soon as possible after they have occurred, and taking corrective action, such as closing in the well. On the night of the Macondo blowout, drillers took about 40 minutes to recognise that a kick had occurred, by which time it was too late. A little over a month earlier the Deepwater Horizon experienced another kick which went unnoticed for 33 minutes. Subsequent analysis indicted that it should have been recognised much earlier[20]. One can therefore easily imagine an indicator based on response time to kicks, which would be relevant at a company or industry level if not at the level of individual wells. The data are all recorded automatically, so, as before, this would be a reasonably robust indicator. Interestingly, BP and Transocean did unannounced tests of response time, perhaps once a week[21]. These tests involved simulating a kick and seeing how long it took crews to recognise and respond to the changed circumstances. This could also serve as the basis for a rig-level indicator of how well blow out risk is being managed.

[19] Federal Register / Vol. 71, No. 73 / Monday, April 17, 2006 / Rules and Regulations 1964
[20] BP, *Deepwater Horizon Accident Investigation Report*, September 2010, p107; see also BP submission to NAE, p9
[21] Spraghe, CSB p110

Cement failures

Another potentially useful indicator of blowout risk is number of cement failures. The Macondo blowout was initiated by an unrecognised cementing failure. Moreover there had been two previous cementing failures higher up the well. The MMS study referred to earlier found that of the 39 blowouts in the 15 year period under consideration, 18 had been initiated by cementing failures. Driving down the rate of cement failure would thus not only be desirable from a commercial point of view, but also from a safety point of view. Number of cement failures is an indicator that the regulator should consider tracking.

Other indicators of increased risk

The indicators discussed so far relate to immediate precursor events. A more comprehensive list of indicators that might be used in the offshore drilling context has recently been published by Norwegian researchers[22]. They identify several categories of potential indicators, as follows:

Well incidents

- Too low mud weight
- Gas cut mud
- Annular losses
- Drilling break
- Ballooning
- Swabbing
- Poor cement
- Formation breakdown
- Improper fill up

Operator response

- Time from first indication well incident to first response
- Evaluation of well response action
- Evaluation of follow-up action
- Time before normal conditions are established

Technical condition of safety critical equipment

- Pipe and casing handling
- Cementing
- Well monitoring
- Mud pumps
- Digital positioning
- Power management

[22] Skogdalen J, Utne I & Vinnem J, "Developing safety indicators for preventing offshore oil and gas deepwater drilling blowouts", *Safety Science,* Volume 49, Issues 8-9, October 2011, Pages 1187-1199

Power generation

Human and organisational factors

Work practices
Competence
Communication
Management
Documentation
Work schedule aspects

Schedule and cost

Comparison between planed and actual total cost
Comparison between planned and actual time used

There is no suggestion here that regulators should seek to monitor all these things. But they are lists from which companies themselves might decide to select indicators most relevant to their operations. The list is far too extensive to be discussed in detail here. However the characteristics of each group are worth noting.

Well incidents. Given that kicks may occur infrequently on many rigs, it makes sense to identify more frequently occurring *precursors to kicks* and to seek to drive down their number. The well incidents in this list were identified in a 2001 study for MMS as the most significant contributors to kicks. By driving down the number of such incidents we reduce the risk of kicks and hence the risk of blowout.

Operator response. This has already been identified as a relevant indicator. This list provides further options.

Technical condition of safety critical equipment. This list refers to mechanical defences or barriers that are supposed to be in place to prevent major accidents. Monintoring the effectiveness of such equipment is a vital part of managing major hazard risk.

Human and organisational factors. Many of the most important risk controls are to be found in this category. It is essential to have indicators of how well these factors are operating to ensure that major hazard risk management is effective. To take just one example, a useful indicator might be the: proportion of safety critical jobs that are filled with by people with the necessary competencies.

These last two categories are concerned with monitoring the effectiveness of barriers. Many companies develop bowtie diagrams for each conceivable major accident event (see figure 2 below). These diagrams explicitly identify the barriers that are being relied on to prevent the event, as well as barriers to ameliorate the consequences of the event. Indicators should be devised to provide information about the status of each every one of these barriers.

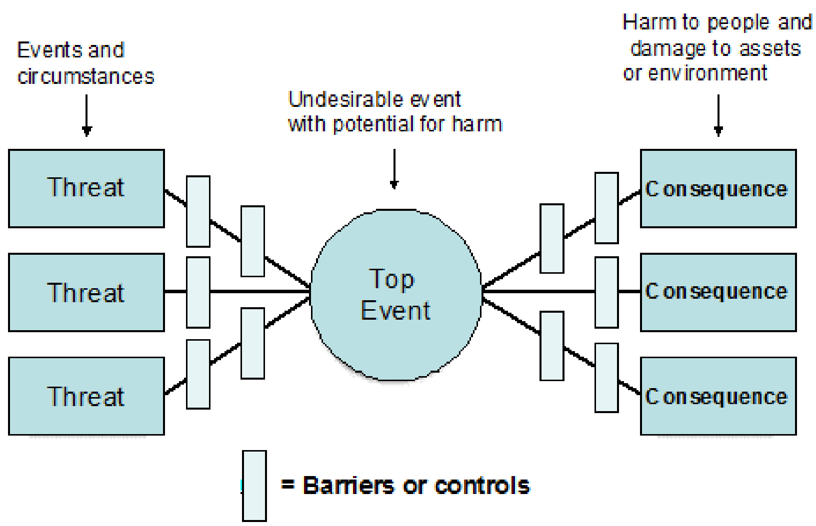

Figure 2: Simple bow tie diagram

The US regulator currently audits operators according to its list of PINCs – potential incidents of non-compliance. It should be auditing against the risk controls specified in bowtie diagrams and it should in particular be ensuring that companies have developed indicators of how well these defences are functioning.

Schedule and cost. This last category is more speculative. It is based on the presumption that risky behaviour may be more likely when schedules and costs have been over-run. This is something that both companies and regulators might like to consider.

BP drilling indicators since Macondo

Since the Macondo incident BP has developed a new set of indicators relevant to drilling risk and particularly blowout risk[23]:

> # of well control and/or BOP activation events (roughly speaking, kicks)
> well control (i.e. kick) incident investigations - overdue actions
> approved deviations from engineering technical practices (presumably the fewer the better)
> rig safety critical equipment failures –overdue actions
> # of wells with sustained casing pressure
> # of wells with failed sub-surface safety valve or down-hole safety valve
> # of BP Macondo incident investigation report recommendations implemented

BP says says it is "tracking" these indicators, although how it plan to make them matter is not clear. (For instance, will they be included in performance agreements?)

[23] BP Submission to the National Academy of Engineers, May 5, 2011, p51

First in the above list is number of kicks; clearly BP now sees this as an important indicator of how well it is managing blowout risk. The third in the list also deserves particular attention. Many companies have technical procedures that engineers are supposed to follow in designing wells. However there is often also a formal procedure for allowing deviations. A large number of deviations can mean one of two things. Either the procedures are not appropriate, or deviations are occurring simply for reasons of convenience or cost. It is therefore appropriate to seeks to drive down the number of authorised deviations, either by improving the procedures themselves, or by ensuring stricter compliance with them. A related indicator is the number of safety by-passes that are in place for more than a specified period, say 30 days. This, too, is an indicator which needs to be driven downwards.

Recommendations

The regulator should develop the following indicators for drilling operations and mandate their reporting:

- Number of kicks
- Response time to kicks
- Number of cementing failures
- Number of gas alarms

Operators should develop indicators to provide information on how well their bowtie defences/controls are functioning. The regulator should audit operators to ensure that such systems are in effect.