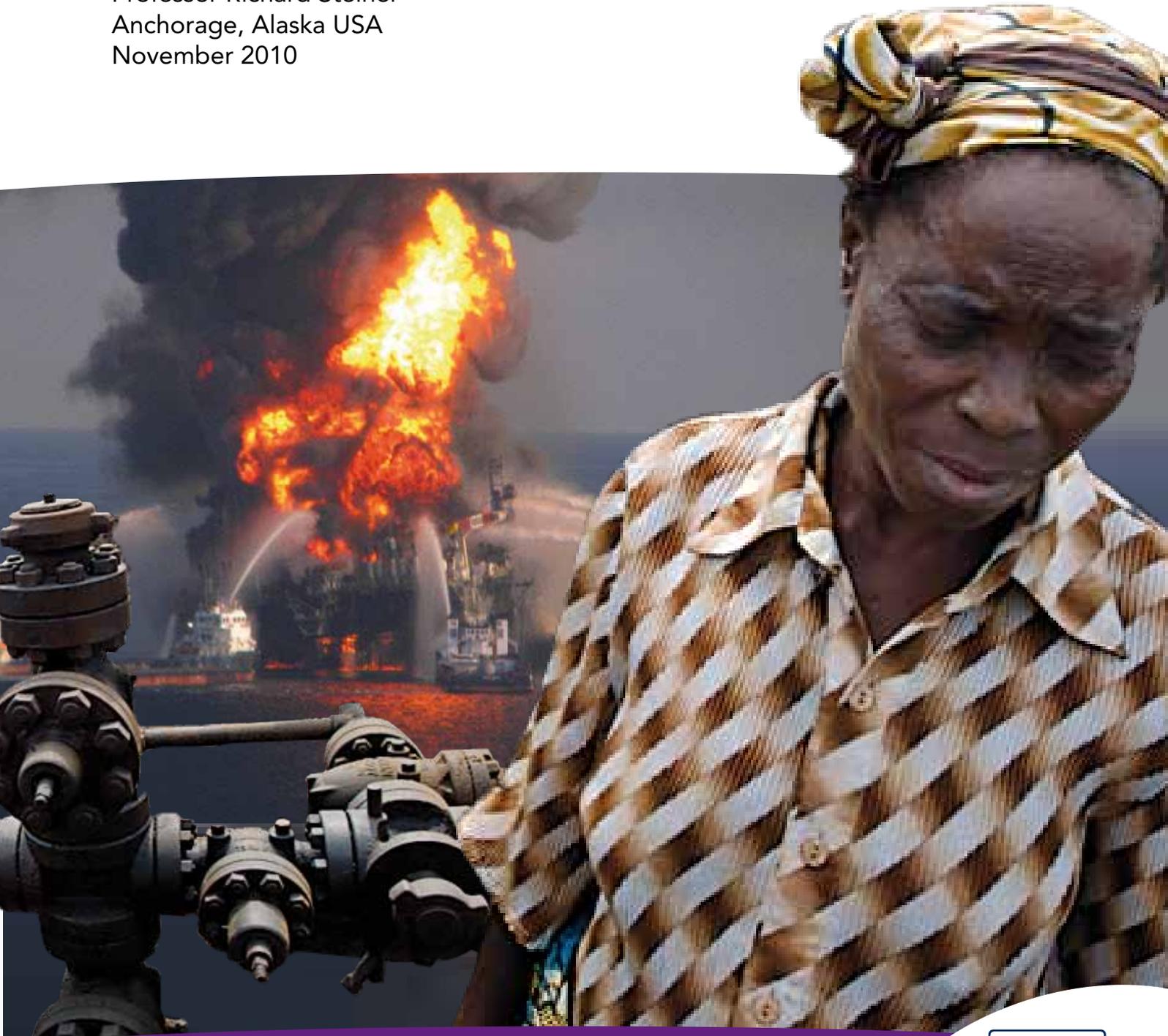


Double standard

Shell practices in Nigeria compared with international standards to prevent and control pipeline oil spills and the Deepwater Horizon oil spill

Professor Richard Steiner
Anchorage, Alaska USA
November 2010



Friends of the Earth Netherlands



About the author



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Credits

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Executive summary

While the official estimates are that 4.1 million barrels spilled into the Gulf of Mexico this summer, recent estimates suggest that over the 50-year history of oil operations in the Niger Delta, some 9 to 11 million barrels of oil have been spilled, and millions of tons of emissions have entered the atmosphere from gas flaring. While the Gulf spill continues to be cleaned up, most spills in the Delta are left unattended. And while the injured environment in the Gulf stands to receive substantial funding and government attention, such environmental damage in the Niger Delta is left largely unattended. Clearly this constitutes a double standard, and far greater attention needs to be paid to the chronic long-term damage from oil and gas operations in the Niger Delta. This report concludes that Shell has conducted its petroleum operations in Nigeria far below commonly accepted international standards used elsewhere in the world.

Oil spills in the Niger Delta

The oil industry has an enormous physical presence in the environmentally sensitive, highly populated Niger Delta of Nigeria. Throughout 50 years of oil production, this ecologically productive region has suffered extensive habitat degradation, forest clearing, toxic discharges, dredging and filling, and significant alteration by extensive road and pipeline construction from the petroleum industry. Of particular concern in the Niger Delta are the frequent and extensive oil spills that have occurred. Spills are under-reported, but independent estimates are that at least 115,000 barrels (15,000 tons) of oil on average are spilled into the Delta each year, making the Niger Delta one of the most oil-impacted ecosystems in the world.

The Niger Delta can be regarded as a High Consequence Area for oil spills, requiring additional risk-reduction measures from oil companies. Oil spills have a significant impact on the natural resources upon which many poor Niger Delta communities depend. Drinking water is polluted, fishing and farming are significantly impacted,

and ecosystems are degraded. Oil spills significantly affect the health and food security of rural people living near oil facilities. Additionally, oil spills and associated impacts of oil and gas operations have seriously impacted the biodiversity and environmental integrity of the Niger Delta.

There has been a significantly higher rate (spills per length of pipeline) of serious pipeline spills in the Niger Delta than in developed countries such as the U.S., beyond that accounted for by sabotage. This, and other evidence, suggests that oil companies operating in the Niger Delta are not employing internationally recognized standards to prevent and control pipeline oil spills.

Nigerian law on oil spills

In order to prevent oil spills, Nigerian law requires oil companies to ensure 'good oil field practice' by complying with internationally recognized American Petroleum Institute (API) and American Society of Mechanical Engineers (ASME) standards for all petroleum production and transportation operations. To control oil spills, Nigerian law requires companies to take 'prompt steps' and initiate clean up operations within 24 hours of the spill. As such, government oil spill prevention and response requirements for Shell in Nigeria are essentially the same as anywhere Shell operates globally.

Internationally recognized standards

The report provides an overview of internationally recognized 'good oil field practice' for critical petroleum system components that are most relevant to oil operations in the Niger Delta: pipeline integrity, sabotage (Intentional Third Party Damage) prevention, and oil spill response.

The development of standards and regulations for pipeline integrity globally has followed those developed in the United States. The U.S. system, called Integrity Management (IM), is required by

law and is used around the world as the international 'best practice' standard to meet. In Alaska, additional requirements exist, namely that 'Best Available Technology' (BAT) must be applied in all oil and gas operations.

As most parts of the Niger Delta meet the criteria defined in the U.S. as High Consequence Areas for oil spills (populated area, drinking water area, or productive ecosystem), oil companies in the Niger Delta are implicitly required by Nigerian law to comply with the API standards for High Consequence Areas. In addition to being a High Consequence Area, the Niger Delta is an area susceptible to damage from third parties (sabotage, illegal bunkering). The American Petroleum Institute (API) has developed guidelines to protect operators from the risk of terror attacks and vandalism. To be in compliance with Nigerian law requiring international standards, oil companies in the Niger Delta must meet this standard.

Performance of Shell Nigeria

For several reasons (listed below), the report concludes that Shell Nigeria continues to operate well below internationally recognized standards to prevent and control pipeline oil spills, and thus is out of compliance with Nigerian law:

- lack of implementing 'good oil field practise' with regard to pipeline integrity management (particularly the U.S. IM regulations, API standards, and Alaska's Best Available Technology requirements);
- delay in initiating an Asset Integrity Review and Pipeline Integrity Management System (PIMS) for Shell Nigeria. Shell Nigeria admits it has a backlog in its asset integrity program;
- questionable adequacy of Shell Nigeria's Asset Integrity Review and PIMS, and lack of independent oversight;
- lack of reference to and attention by Shell Nigeria to the Niger Delta as a High

Consequence Area for oil spills

- lack of adequate attention by Shell Nigeria to the Niger Delta as an area in which oil facilities are susceptible to Intentional Third Party Damage, requiring enhanced pipeline integrity and monitoring procedures;
- exceptionally high number, extent, and severity of oil pipeline spills in the Niger Delta before, during, and after their Asset Integrity Review and PIMS;
- lack of transparency in Shell Nigeria – the Asset Integrity Review, Pipeline Integrity Management System (PIMS), Joint Operating Agreement, and its Oil Spill Contingency Plan (OSCP) should submit to independent third-party evaluation; and
- lack of adequate oil spill response capability and performance of Shell Nigeria

Preface

The 2010 offshore oil blowout in the Gulf of Mexico attracted a great deal of world attention and concern, and rightfully so. The disaster killed 11 crewmen, and caused the largest accidental marine oil spill in history. The damage has been enormous, and will last for years.

As a result of the Gulf oil disaster, greater attention is now being paid to the true costs of oil development through out the world. This is a welcome development. Yet it is unfortunate that as political leaders closely attend to the issues of oil spills in industrialized countries, they continue to ignore similar issues in developing countries.

In this regard, while the official estimates are that 4.1 million barrels spilled into the Gulf of Mexico this summer, recent estimates suggest that over the 50-year history of oil operations in the Niger Delta, some 9 to 11 million barrels of oil have been spilled, and millions of tons of emissions have entered the atmosphere from gas flaring.

The Niger Delta has become a textbook example of the environmental, economic, and social problems that derive from oil – where oil is more curse than blessing. Although oil has provided several hundred billion dollars to the transnational companies and the federal government in Nigeria, the 30 million people living in the oil-producing region of the Delta have benefited little from this wealth, and today live in dire poverty. The inequitable distribution of proceeds from oil has led to a long-term violent rebellion that has destabilized the region, and the environment, economic, and social systems have been left severely degraded. The Niger Delta today is one of the most heavily oil-impacted regions in the world.

Oil companies operating in the Niger Delta, in particular Shell, blame most of the oil spills on sabotage and illegal bunkering (theft) by local community members. It is in the company's perceived financial interest to allege such, as they feel this releases them from legal responsibility to clean up spills or compensate the local communities. Companies blame their joint venture partner – Nigeria National Petroleum Corpora-

tion (NNPC) – with not funding infrastructure upgrades necessary to reduce spill risk. And, with the dysfunctional government oversight in Nigeria, oil companies habitually under report spill events, size and impacts, and misreport causes as suits their purpose. Local communities on the other hand assert that most of the spills are caused by inadequate maintenance and integrity standards of the oil pipelines. Regardless of the cause for spills, the Delta environment continues to be extensively degraded.

The differences between the response in the U.S. to the oil spill in the Gulf of Mexico and that in the Niger Delta couldn't be more clear: In the Gulf, the oil outflow has been stopped, but substantial oil outflow continues each and every day into the Niger Delta. In the Gulf, economic losses are being compensated by BP's \$20 billion (USD) claims fund, but economic losses in Nigeria have received little compensation. While the Gulf spill continues to be cleaned up, most spills in the Delta are left unattended. The financial valuation of the environmental damage caused by 50 years of oil and gas activities in the Niger Delta - taking into account the unique and productive character of the ecosystem as well as comparable valuations on other such ecosystems – is 10's of billions of U.S. dollars.

And while the injured environment in the Gulf stands to receive substantial funding and government attention, such environmental damage in the Niger Delta is left largely unattended. Clearly this constitutes a double standard, and far greater attention needs to be paid to the chronic long-term damage from oil and gas operations in the Niger Delta.

As public and political attention typically focuses more on environmental integrity in developed nations and ignores that in developing ones, company and governmental attention to oil infrastructure integrity and spill risk tends to follow the same pattern. That is, transnational companies generally apply higher standards in their conduct in industrialized nations than in non-industrialized nations.

The following report gives a glimpse into this double standard dynamic. The report concludes that a major transnational oil company – Shell – has applied lower standards with regard to pipeline integrity and environmental risk management in Nigeria compared with its activities in other parts of the world. Shell knows how to do better, but apparently sees no need to do so in Nigeria. From an environmental justice standpoint alone, this is unacceptable and must end. It is time for the excuses to end. If Shell cannot secure their oil infrastructure from the alleged Intentional Third Party Damage in Nigeria, then they should not be doing business there.

But more broadly, we all live on the same small planet together. There is no “elsewhere” in which business is conducted. The manner in which one company conducts its oil and gas operations in Nigeria affects every one in the world, human and non-human. Further, as most of the oil and gas produced in Nigeria is exported

to Europe and the U.S., consumers in these areas bear some of the responsibility for the poor practices in Nigeria. We can no longer just pay attention to the environmental, economic, and social impacts of oil and gas produced within our respective borders, but we now need to attend to oil industry impacts anywhere and everywhere oil and gas is produced.

It is time for this double standard to end, for one Best Practice Standard to be applied globally to all industrial activities, and to minimize impacts as much as possible. No region of the world should suffer a double standard in corporate or governmental treatment.

It is hoped that this report will help to achieve this goal.

*Richard Steiner, Professor and Consultant
Asaba, Delta State, Nigeria October 1, 2010
(Nigeria's 50th anniversary of Independence)*

**Workers
contracted
by BP clean
up oil on
the beaches
of Port
Fourchon**



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Overview: The Gulf of Mexico Deepwater Horizon disaster

On April 20, 2010 – just weeks after U.S. President Barack Obama announced an expansion of offshore oil drilling in U.S. waters saying that “oil rigs today generally don’t cause spills – they are technologically very advanced” – the Deepwater Horizon drilling rig exploded and sank in the Gulf of Mexico, killing 11 workers and injuring others, and causing the largest accidental oil spill in world history. The rig, leased by BP, was drilling an exploratory well – Macondo - in 1,700 m of water, and had just discovered a major oil and gas reservoir 4,000 m beneath the seabed.

Like most industrial disasters, the Deepwater Horizon disaster was caused by a series of human errors and mechanical malfunctions. The rig had experienced several gas kicks in the days before the explosion, where managers should have known there was increased risk of a blowout. Yet in their rush to seal and disconnect from the exploratory well and move on to other drilling locations (they were already 43 days behind schedule, at a cost of about \$1 million USD / day), rig managers made several decisions to save time and cost that increased risk of a blowout. The cement job in the well casing may not have set correctly, and there were fewer installed barriers to natural gas kicks. The crew on board misread the negative pressure test of the well, and had not conducted a cement bond log that would have told them the cement job wasn’t adequate. And when gas kicked up the well on April 20, the last line of defense – the blowout

preventer at the seabed wellhead – failed. The drilling crew diverted the gas flow through the Mud Gas Separator system onboard rather than overboard, which encountered an ignition source leading to the explosion. Under U.S. law, BP holds ultimate responsibility for the disaster, as it was the leaseholder and operator. Other companies with some responsibility include Transocean (rig owner), Halliburton (cement contractor), and Cameron International (BOP manufacturer).

BP had not planned for a blowout of a deep-water well, and had no equipment or plan with which to stop it. Several failed attempts were made to kill the blowout at the seabed wellhead. In May, a 90-ton “Pollution Containment Chamber” was built and lowered over the gushing wellhead, but it clogged with methane hydrate crystals and failed. Then, a “Riser Insertion Tube” was inserted into the broken riser, and began collecting perhaps 2,000 barrels / day. Next, the broken riser was cut off, and a Lower Marine Riser Package (LMRP) was fitted atop the wellhead collecting perhaps 10,000 bbls/day to surface vessels. A “top kill” was attempted, where thousands of tons of heavy drilling mud and “junk shots” of synthetic materials were pumped down against the force of the blowout through the blowout preventer. But the force of the blowout was too great to overcome from above, and the top kill was suspended. The blowout was stopped on July 15 when a containment stack was placed on the failed blowout preventer, and then finally on September 18 by a relief well drilled to intersect the failed well bore down near the reservoir, with muds and cement pumped into the Macondo well and up with the force of the blowout from below – a “bottom kill.” So, it took BP about 3 months to stop the blowout, and 5 months to finally seal the well.

Oil spewed into the Gulf of Mexico from the deep-sea wellhead at an estimated 60,000 barrels/day (2.5 million gallons/day) for almost 3 months. Before being brought under control, the blowout released an estimated 170 million gallons of oil, making this the largest accidental oil spill in history. Coming out at 1,700 m deep and 70 km offshore,

Polluted lake in the Nigerdelta, 2008



KADIR VAN LOHUIZEN / NOOR



the spill was very different than surface spills from tankers or shallow water blowouts. Much of the oil that reached the surface was heavily emulsified with water, making it difficult to contain or recover. Extensive underwater plumes of dilute oil and gas spread at-depth across the Gulf.

The environmental, economic, and social damage from the spill were enormous. Oil spread over 40,000 km² of the northern Gulf of Mexico, and oiled over 1,000 km of shoreline, from Louisiana to Florida. Much of the environmental damage occurred in the offshore pelagic ecosystem, where blue fin tunas and other large fish species were spawning planktonic eggs at the time, but this injury was out-of-sight of coastal observers and television cameras. The millions of gallons of oil that washed ashore attracted more public attention. Shoreline oiling occurred on sand beaches, and sensitive wetlands and marshes, including small low-lying islands where tens of thousands of seabirds were nesting. Thousands of birds, dolphins, sea turtles, and juvenile fish were killed in the first few months, and many more suffered sub-lethal injury. There is concern also for deepwater corals and deep-sea cold seep ecosystems that may have been exposed to subsurface plumes. Some permanent loss of

inshore habitat likely occurred due to coastal vegetation loss from direct oiling, thus accelerating erosion of coastal islands. The spill is expected to cause long-term environmental injury. Fishing was shutdown for the year in about 1/3 of federal waters of the Gulf of Mexico, and tourism slowed dramatically, causing significant disruption in the local economic and social systems. The multi-billion dollar spill response was the largest in history – 7,000 vessels, 500 skimmers, 800 km of booms, over 2 million gallons of chemical dispersants were applied at the deep-sea blowout and on the sea surface, and several hundred in-situ burns were conducted. Yet with all of this, only about 3% of the spilled oil was ultimately recovered from the water. In an unprecedented gesture, BP agreed to establish a \$20 billion (USD) claims fund to compensate people for economic losses outside of the judicial process. This could avert years of legal wrangling over claims, and expedited compensation to claimants. But BP has resisted establishing a similar fund for environmental restoration.

Many efforts were launched in the US Congress in 2010 to increase the safety of offshore drilling and improve government oversight, including establishing Citizens Advisory Councils, elimi-

Gulf of Mexico Deepwater Horizon disaster

nating liability limits, better drilling technology (e.g., improved blowout preventers and companion relief wells, etc.), and a restructured government oversight process.

But the Deepwater Horizon disaster brought into sharp public focus not just the risks of offshore oil development and failed government oversight, but more broadly the “hidden” costs of the continued global dependence on oil – important biological and cultural areas damaged by oil development and transportation, wars fought to secure oil supplies, health costs from breathing emissions, climate change, and frequent oil spills. As oil companies have already developed much of the easily accessible reservoirs on shore and in shallow water, they are now moving into the more extreme environments, such as the deep ocean high-pressure reservoirs in the Gulf of Mexico, Brazil, and West Africa, as well as the Arctic Ocean. The risks of drilling in extreme environments are becoming apparent. As well, other regions globally that have suffered from chronic oil spills, such as the Niger Delta, are now receiving more public attention as a result of the Gulf spill.

**Nigerdelta,
2004**



1. Oil spills in the Niger Delta

1.1 The Niger Delta

The Niger Delta, situated in the southern part of Nigeria, occupies a surface area of about 112.000 square kilometres, representing 12% of Nigeria's total surface area. Its present population is estimated to be about 30 million people, living in approximately 3.000 communities (NDDC 2006), making it one of the most densely populated regions of Africa.

The Niger Delta is considered one of the 10 most important wetlands and coastal marine ecosystems in the world (IUCN/CEESP 2006). The Delta contains habitat for many threatened species found nowhere else in the world, including several primates, ungulates, and birds; a vast mangrove ecosystem; and nursery habitat for many fish populations important along the West African coastline. Of the people residing in the Niger Delta 75% rely on natural resources for a living, mainly subsistence farming and fishing. The people of the Niger Delta rank consistently low on United Nations indices for development, income, health, and gender (UNDP 2006).

Most of the oil production in Nigeria takes place in the Niger Delta. Nigeria depends on the oil industry for 95% of export earnings and 80% of government revenue (Shell 2008a). Nigeria consistently ranks in the top ten of oil producing nations in the world, and is an OPEC member.

The following table illustrates the enormous physical presence of the oil industry in the Niger Delta. By comparison: the surface area of the Netherlands is 41.500 square kilometres.

1.2 Consequences of oil spills in the Niger Delta

In May 2006, an independent team of environmental experts from Nigeria, the U.K., and the U.S. conducted a preliminary Natural Resource Damage Assessment in the Niger Delta. This independent assessment, with participation of Nigeria's Ministry of Environment; The Nigeria Conservation Foundation; the IUCN Commission on Environmental, Economic and Social Policy; and this author; found the following (IUCN/CEESP 2006):

- The Niger Delta is one of the world's most severely petroleum-impacted ecosystems.
- Oil development occurred in the Delta without a comprehensive, strategic plan, which would have protected its natural resources. Many of the oil facilities and operations are located within sensitive habitats - including areas vital to fish breeding, sea turtle nesting, mangroves and rainforests - that have often been severely damaged, contributing to increased biodiversity loss and poverty.
- The damage from oil and gas operations

The physical presence of the oil industry in the Niger Delta (NDDC 2006)

Land area within which the network of pipelines are located	31.000 km²
Number of oil wells drilled in the Niger Delta Region	5.284
Number of flow-stations for crude oil processing	257
Length of main oil and gas pipelines in the region (flowlines between oil wells and flow-stations not included)	7.000 km
Number of export terminals	10
Number of communities hosting oil / gas facilities	1.500

is chronic and cumulative, and has acted synergistically with other sources of environmental stress to result in a severely impaired coastal ecosystem and compromised livelihoods and health of the region's impoverished residents.

- In addition to spills, damage from oil and gas operations in the region has included extensive habitat degradation from road building, forest clearing, dredging and filling; pollution from gas flaring and operational discharges, and increased population pressure from immigration to the region.
- Rural communities in the Niger Delta have suffered most of the environmental and social costs of 50 years of oil development.
- Oil companies operating in the Delta have not employed Best Available Technology and practices that they use elsewhere in the world – a double standard. The oil companies can and should improve their environmental performance in the region.
- The financial valuation of the environmental damage caused by 50 years of oil and gas activities in the region - taking into account the unique and productive character of the ecosystem as well as comparable valuations on other such ecosystems – is 10's of billions of U.S. dollars.

The findings of this 2006 study are consistent with that of other studies. Orubu, et.al. 2004 reported that:

'Massive oil spills occurring in riverine areas in the Niger Delta have also done untold damage to the aquatic ecosystem, particularly in the mangrove swamp forest zone.

A number of these spills have been attributed to corrosion of ageing facilities (Shell 1995), and relative disregard for good oil field practices (Nwankwo et al., 1998; Ndifon, 1998).'

The sensitivity of the area to oil pollution is confirmed in annual reports of Shell Nigeria (Shell 2007a):

'The ecosystem [of the Niger Delta] is particularly sensitive to changes in water quality, such as salinity or pollution, or to changes in hydrology of the region.'

Nwilo and Badejo, 2004 summarize the serious effects of oil spills in the Niger Delta as follows:

'Life in this region is increasingly becoming unbearable due to the ugly effects of oil spills, and many communities continue to groan under the degrading impact of spills (Oyem, 2001). In the Nigerian Coastal environment a large areas of the mangrove ecosystem have been destroyed. The mangrove was once a source of both fuel wood for the indigenous people and a habitat for the area's biodiversity, but is now unable to survive the oil toxicity of its habitat. The oil spills also had an adverse effect on marine life, which has become contaminated; in turn having negative consequences for human health from consuming contaminated seafood. Oil spill has also destroyed farmlands, polluted ground and drinkable water and caused drawbacks in fishing off the coastal waters.'

The United Nations Environment Programme, states the following with regard to oil spill impacts in the Niger Delta (UNEP 2006):

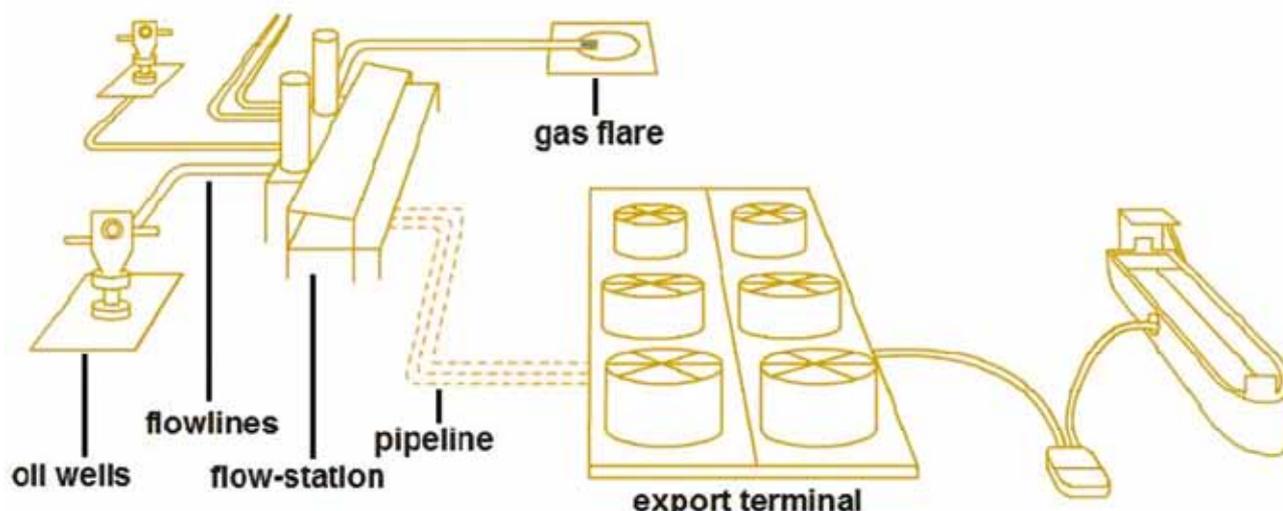
'This is a major impact on the coastal environment particularly in the Niger Delta area where oil prospecting is extensive. (. . .) Potential impacts of oil spills include among others:

- (i) High mortality of aquatic animals
- (ii) Contaminations of human lathered
- (iii) Impairment of human health
- (iv) Loss of biodiversity
inbreeding grounds
- (v) Vegetation destruction and other ecological hazards
- (vi) Loss of portable and industrial water resources
- (vii) Reduction in fishing activation
- (viii) Poverty, rural underdevelopment and bitterness'

1.3 Amount of oil spilled in the Niger Delta

Oil spills in the Niger Delta have been extensive, difficult to assess, and dramatically under-reported. Reasons for this under-reporting include difficulty in accessing some spill sites (due to swamp conditions and remoteness), security concerns limiting access, some spills occurring away from community locations, a long time-lag between the initiation of a spill and it's detection, the high volatility of the oil causing an esti-

Figure 1: Typical oil production in the Niger Delta



A flow-station receives the oil and gas transported through flowlines after extraction from the wells. At the flow-station, oil and gas are separated. The gas is usually flared (burned), but in some cases it is captured into a pipeline. The oil is pumped into a main, high-pressure pipeline for transport to an export terminal, through several other flow-stations where pumps maintain pipeline pressure.

mated 50% to evaporate within 24 – 48 hours, intentional company and government under-reporting, and inadequate government oversight. As Orubu, 2004 stated:

'Most oil companies have not generally complied with the statutory requirement in the Environmental Guidelines and Standards for the Petroleum Industry (EGASPIN) to report all cases of spills within 24 hours.'

Unfortunately, few reliable, comprehensive databases reporting spill volumes and locations in the Niger Delta exist. Government and operating companies maintain their own data on spills, but these cannot be considered reliable as both the government and operators seek to limit their legal liability for claims from oil spill damage.

A team of independent local and international experts, including the author (IUCN/CEESP 2006), estimated that on the order of between 9 million – 13 million barrels (1.5 million tons) of oil has spilled in the Niger Delta ecosystem over the past 50 years. This is equivalent to an average of about 200,000 barrels (30,000 tons) / year.

Analysis (by Nwilo and Bodejo, 2001) reported similar spill volumes in the Niger Delta, based

largely on government (Department of Petroleum Resources) spill statistics, as follows:

Between 1976 and 1998 a total of 5724 incidents resulted in the spill of approximately 2,571,113.90 barrels of oil into the environment. Some major spills in the coastal zone are the GOCON's Escravos spill in 1978 of about 300,000 barrels, Shell Petroleum Development Corporation's (SPDC's) Forcados Terminal tank failure in 1978 of about 580,000 barrels, Texaco Funiwa-5 blow out in 1980 of about 400,000 barrels, and the Abudu pipe line spill in 1982 of about 18,818 barrels (NDES, 1997). Other major oil spill incidents are the Jesse fire incident which claimed about a thousand lives and the Idoho Oil spill in January 1998, in which about 40,000 barrels were spilled into the environment (Nwilo et al, 2000). The most publicised of all oil spills in Nigeria occurred on January 17, 1980 when a total of 37.0 million litres of crude oil got spilled into the environment. This spill occurred as a result of a blow out at Funiwa 5 offshore station. The heaviest recorded yearly spill so far occurred in 1979 and 1980 with a net volume of 694,117.13 barrels and 600,511.02 barrels respectively.



PETER RODERICK

Gasflare in Nigerdelta, 2006

The Nwilo and Bodejo estimate represents an average of 117,000 barrels spilled / year.

The 2006 Niger Delta Human Development Report of the United Nations Development Programme (UNDP 2006) states:

'Available records show that a total of 6,817 oil spills occurred between 1976 and 2001, with a loss of approximately three million barrels of oil.'

This represents an average of 273 oil spills and 115,000 barrels / year spilled in the Niger Delta in the period 1976-2001 (see appendix 2). The relative agreement (115,000 – 200,000 barrels / year) of the above three independent assessments lends additional statistical confidence to these spill estimates, and clearly shows the historic severity of the oil spill problem in the Niger Delta. This likely represents a higher oil spill rate than anywhere else in the world.

In contrast, Shell (which is responsible for about 50 per cent of petroleum production from the Delta) reported for the period 1998 – 2009 a total volume of 491,627 barrels of oil spilled, or about 41,000 barrels spilled / year. For this period, Shell Nigeria reported an average of 250 spills each year, averaging 160 barrels (26,000 litres) each (see appendix 1). The author (and other observers) feels that Shell Nigeria's reporting of spill numbers and volumes represents a significant under-reporting of the actual spill frequency and volume.

In the United States, authorities recorded on average 143 significant oil pipeline incidents per year in the period 1988-2007, spilling on average a total of 75,000 barrels / year into the environment (US-DOT, 2008). The United States has over 165,000 miles of oil transmission lines, while the Niger Delta has only about 10,000 miles of high-pressure oil pipelines and flow lines. So, while the pipeline network of the Niger Delta is 16 times shorter than the pipeline network in the USA, more oil is being spilled from the pipeline system on an absolute basis, and the spill rate (spills / km of pipeline) is vastly greater in Nigeria.

With regard to quantity of oil spilled vs. quantity recovered for the period 1976 - 1998, Orubu et.al., 2004 reported the following:

Of this (total) amount, only about 15.91 per cent was recovered, on the average, implying that about 84.09 percent of the cumulative spill was lost to the environment!

1.4 Conclusion: oil spills in the Niger Delta

The oil industry has an enormous physical presence in the environmentally sensitive, highly populated Niger Delta of Nigeria. Throughout 50 years of oil production, this ecologically productive region has suffered extensive habitat degradation, forest clearing, toxic discharges, dredging and filling, and significant alteration by extensive road and pipeline construction from the petroleum industry. Of particular concern in the Niger Delta are the frequent and extensive oil spills that have occurred. Spills are under-reported, but independent estimates are that at least 115,000 barrels (15,000 tons) of oil are spilled into the Delta each year, making the Niger Delta one of the most oil-impacted ecosystems in the world.

The Niger Delta can be regarded as a High Consequence Area for oil spills, requiring additional risk-reduction measures from oil companies. Oil spills have a significant impact on the natural resources upon which many poor Niger Delta communities depend. Drinking water is polluted, fishing and farming are significantly impacted, and ecosystems are degraded. Oil spills significantly affect the health and food security of rural people living near oil facilities. Additionally, oil spills and associated impacts of oil and gas operations have seriously impacted the biodiversity and environmental integrity of the Niger Delta.

There has been a significantly higher rate (spills per length of pipeline) of serious pipeline spills in the Niger Delta than in developed countries such as the U.S., beyond that accounted for by sabotage. This, and other evidence, suggests that oil companies operating in the Niger Delta are not employing internationally recognized standards to prevent and control pipeline oil spills.

2. Nigerian law on oil spills

2.1 Oil Spill Prevention

The Nigerian Petroleum Act of 1969 grants the Minister of Petroleum Resources the statutory authority to revoke an oil operator's license to operate if the operator does not comply with 'good oil field practice.'

The Mineral Oils (Safety) Regulations of 1962 (incorporated in the Nigerian Petroleum Act) states that good oil field practice compliance:

'shall be considered to be adequately covered by the appropriate current Institute of Petroleum Safety Codes, the American Petroleum Institute [API] Codes, or the American Society of Mechanical Engineers [ASME] Codes.'

The Petroleum Drilling and Production Regulations of 1969 (implementing the Petroleum Act) require companies to:

'adopt all practicable precautions including the provision of up-to-date equip-

ment (in order to prevent pollution, and if pollution does occur they must take) 'prompt steps to control and, if possible, end it'

The operators are also required by these regulations to maintain all installations in good repair in order to prevent:

'the escape or avoidable waste of petroleum', (and to cause) 'as little damage as possible to the surface of the relevant area and to the trees, crops, buildings, structures, and other property thereon.'

The Nigerian Department of Petroleum Resources (DPR) further expanded these requirements in 1991 when they instituted the Environmental Guidelines and Standards for the Petroleum Industry (EGASPIN), which was revised and updated again in 2002. EGASPIN confirms that oil and gas operations are governed by the Nigerian Petroleum Act and subsequent federal legislation. (NG-EGASPIN 2002).

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2.2 Oil Spill Response

Regarding response to oil spills, EGASPIN (page 148) states, among other things:

'Clean-up shall commence within 24 hours of the occurrence of the spill.'

'For inland waters/wetland, the lone option for cleaning spills shall be complete containment and mechanical/manual removal. It shall be required that these clean-up methods be adopted until there shall be no more visible sheen of oil on the water.'

'Clean-up of oil spills in contaminated environments shall be conducted in such a manner as not to cause additional damages to the already impacted environment'.

EGASPIN stipulates that oil contamination of soil, sediment and surface water may not exceed specified levels that are consistent with internationally recognized standards for maximum levels of oil pollution.

Section 4.6 of this report below contains a more detailed discussion of Shell Nigeria's lack of compliance with EGASPIN.

2.3 Conclusion

In order to prevent oil spills, Nigerian law requires oil companies to ensure 'good oil field practice' by complying with internationally recognized American Petroleum Institute (API) and American Society of Mechanical Engineers (ASME) standards for all petroleum production and transportation operations. To control oil spills, Nigerian law requires companies to take 'prompt steps' and initiate clean up operations within 24 hours of the spill. As such, government oil spill prevention and response requirements for Shell in Nigeria are essentially the same as anywhere Shell operates globally.

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3. Internationally recognized standards

3.1 Introduction

This chapter provides an overview of internationally recognized standards with regard to pipeline oil spill prevention and response.

Pipeline integrity

With regard to internationally recognized standards for pipeline management, the American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), U.S. Integrity Management (IM) for High Consequence Areas (HCAs), and the Alaska Best Available Technology (BAT) industry standards, taken together, represent a widely accepted 'good oil field practise' standard for petroleum pipeline management.

It is important to recognize that there does not exist one universal 'good oil field practise' standard for design, inspection and maintenance of pipelines from which to compare practices around the world. There are many overlapping sets of criteria and standards. As the United States has over 165,000 miles of oil transmission lines and 295,000 miles of gas transmission lines, it has more mileage of petroleum pipelines than most other countries combined (Kruprewicz, 2007). Thus, it is not surprising that the development of standards and regulations globally has followed the U.S. standards. The U.S. pipeline standards have improved dramatically in recent years, particularly since two high-profile pipeline disasters in 1999 at Bellingham, Washington and in 2000 at Carlsbad, New Mexico.

The report 'General Observations on the Myth of a Best International Pipeline Standard.' (Kruprewicz 2007) focuses on high-volume, high-pressure, high-stress steel transmission lines. It states that:

'High-capacity pipelines are capable of quickly releasing (within several minutes) many hundreds of tons of material in the event of a rupture.'

'No one country's current requirements or standards adequately capture all the relevant factors that should prevent a

pipeline failure, or ensure wise selection of pipeline routes.'

'What usually mandates different approaches in pipeline regulation / standards / guidance is: how a specific country addresses the various risks associated with different stages of a pipeline's long lifecycle; the level of detail in specific code / standard / regulations governing application; whether these standards are evolving using newer, and sometimes developing techniques intended to push technical advances (such as newer grades of high stress steel that permit thinner pipe wall to contain pressure); the effectiveness of regulatory "oversight" agencies to enforce such regulations and standards; and the willingness or tolerance of a country's society / government to accept the risk of major loss of life.'

As discussed in Kruprewicz 2007, the basic Design Factor (DF) for pipelines takes into account pressure, pipe grade (yield strength), pipe diameter, and pipe thickness. The basic Design Factor (DF) = Maximum Operating Pressure (MOP) / Specified Minimum Yield Strength (SMYS). The higher is the DF for a pipeline, the greater pressure allowed in the pipe relative to thickness and grade of pipe and closer to design maximum, and thus the greater the risk of failure. Conversely, a lower Design Factor reduces the risk of failure. Design Factors tend to range from 0.8 for pipelines that transit low consequence areas to a low of 0.3 for High Consequence Areas where greater protection is desired (see section 3.3 below). In areas with high population or high consequence of a rupture or spill, 'good oil field practise' would prescribe low Design Factors, say at 0.3, and thus thick wall pipe (where pipe diameter / pipe wall thickness $D/t < 20$). And as Kruprewicz states:

For a given pressure, thicker wall pipe tends to buy an operator time between the introduction of an anomaly to a pipeline and its possible time to failure.

Also, the use of high stress grades of steel (X-100 and X-120) can allow thinner pipe to be used for equal pressures. And as important as the Design Factor in the integrity of oil pipelines is the Quality Assurance / Quality Control (QA/QC) system employed to implement and enforce these standards. If there is sufficient monitoring, maintenance, and repair (QA/QC) on a pipeline system, then a pipeline operator is able to further reduce risk of pipe failure.

Oil Spill Response

The other primary aspect of petroleum system integrity that must be consistent with 'good oil field practices' is that of oil spill response. The generally internationally recognized standard with regard to oil spill response is that a company must be prepared to respond promptly and effectively to a maximum probable discharge (Steiner & Byers, 1990; Steiner, 2000). This requires detailed pre-planning (contingency planning), pre-staging equipment, trained response personnel, early detection, every effort to stop an outflow promptly, every effort to contain and recover as much of the spilled oil as possible as quickly as possible, and serious effort to restore spill-injured environments to their pre-spill condition. Statutory requirements vary across the world, but two models, both in Alaska, USA, serve as 'good oil field practises' by which to compare performance with regard to oil spill response.

3.2 API and ASME standards

3.2.1 American Petroleum Institute (API) Standards Pipeline integrity

The development of consensus standards is one of American Petroleum Institute's oldest and most successful programs (API website). Beginning with the development of its first standards in 1924, API now maintains some 500 standards covering all segments of the oil and gas industry. And through involvement with the International Organization for Standardization (ISO) and other international bodies, API standards are now recognized globally, often as a good oil field practice.

'API is an American National Standards Institute (ANSI) accredited standards developing organization, operating with approved standards development procedures and undergoing regular audits of its processes. API produces standards,

recommended practices, specifications, codes and technical publications, reports and studies that cover each segment of the industry. API standards promote the use of safe, interchangeable equipment and operations through the use of proven, sound engineering practices as well as help reduce regulatory compliance costs, and in conjunction with API's Quality Programs, many of these standards form the basis of API certification programs.' (API website)

Some of the API standards of relevance to pipeline integrity and management include the following:

- Std 1110 Pressure testing of Liquid Petroleum Pipelines, 1999
- Std 1113 Developing a Pipeline Supervisory Control Center, 2000
- RP 1117 Movement of In-service Pipelines, 1996
- API 1130 Computational Pipeline Monitoring, 1995, updated 2002
- Pub 1133 Guidelines: Onshore Pipelines Affecting High Consequence Floodplains, 2005
- Pub 1149 Pipeline Variable Uncertainties and their Effects on Leak Detectability, 1993
- Pub 1155 Evaluation Methodology for Software-based Leak Detection Systems, 1995
- Pub 1156 Effects of Smooth and Rock Dents on Liquid Petroleum Pipelines, 1997
- Pub 1158 Analysis of DOT Reportable Incidents for Hazardous Liquid Pipelines, 1999
- Std 1160 Managing System Integrity for Hazardous Liquid Pipelines, 2001
- Pub 1161 Guidance Document for the Qualification of Liquid Pipeline Personnel, 2000
- RP 1162 Public Awareness Programs for Pipeline Operators, 2003
- Pub 1163 In-line Inspection Systems Qualification Standard, 2005
- Std 1164 SCADA Security, 2004
- RP 1165 Recommended Practice for Pipeline SCADA Displays, 2007
- RP 2200 Repairing Crude Oil, Liquefied Petroleum Gas and Product Pipelines, 1994
- Std 1104 Welding of Pipelines and Related Facilities, 2005
- Prod. # OS0001 Security Guidance for the Petroleum Industry, 2003
- Prod. # OSVA02 Security Vulnerability Assessment Methodology for the Petroleum and Petrochemical Industries, 2004

Courtcase
in the
Netherlands
against Shell



ALBERT TEN KATE / MILIEUDEFENSIE

Shell has been a member of API for decades, and is thus well aware of all such standards.

API Leak Detection System standard

A Leak Detection System standard is embodied in API publication 1130 entitled Computational Pipeline Monitoring (CPM) 1995, which details requirements for effective internal Leak Detection Systems. As well, operators are required to install Emergency Flow Reduction Devices (check valve or remote control valve) on pipeline segments to shut the oil flow down in the event of a rupture or anomaly (see Leak Detection System discussion below).

3.2.2 American Society of Mechanical Engineers (ASME) Standards Pipeline integrity

In addition to API, the American Society of Mechanical Engineers (ASME) also has an extensive history of developing standards for the oil and gas pipeline industry. There are 125,000 ASME members worldwide, and the organization:

conducts one of the world's largest technical publishing operations, holds some 30 technical conferences and 200 professional development courses each year, and sets industrial and manufacturing codes and standards used through-

out the world; there are ASME accredited manufacturers in 60 countries. (ASME 2008).'

ASME developed its first pipeline code (for Pressure Piping) in 1935 which included specifications for the design, manufacture, installation, and testing of oil and gas pipelines. As the industry evolved, rules also evolved for operation, inspection, corrosion control, and maintenance of pipelines. The ASME Vice President for Standards and Codes described ASME to the U.S. Congress in 2002 as follows:

'ASME has two committees responsible for development of pipeline codes: B31.4/11, Liquid and Slurry Piping Transportation Systems; and B31.8, Gas Transmission and Distribution Piping Systems. These committees strive for balanced participation from all stakeholder and interested party groups, and significant efforts are made during the standards development process to encourage the participation of those outside of the pipeline industry. Both the ASME B31.4 and B31.8 have become widely recognized and respected standards both in the U.S. and around the world. In making underwriting decisions, insurers weigh compli-

ance to national standards such as B31.4 and B31.8 critically in their evaluations. As part of its continuing effort to respond to the changing needs of the pipeline industry and provide the greatest measure of protection to the general public, ASME International released a supplement to the B31.8 standard in January 2002. The supplement, known as B31.8S, was developed using the same consensus and public review process as all other ASME codes and standards. We believe it to be a scientifically sound and technically reasonable standard that will serve the industry and the public well.’
(Donald Frikken, VP for Codes and Standards ASME, 2002)

The ASME code with most relevance to the Niger Delta oil spill situation is ANSI/ASME B31.4 entitled: Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids, from 1998, updated in 2002. As stated on the ASME website:

‘This Code (B31.4) prescribes requirements for the design, materials, construction, assembly, inspection, and testing of piping transporting liquids such as crude oil, (...) between producers’ lease facilities, tank farms, natural gas processing plants, refineries, stations, ammonia plants, terminals (marine, rail and truck) and other delivery and receiving points. Piping consists of pipe, flanges, bolting, gaskets, valves, relief devices, fittings and the pressure containing parts of other piping components. It also includes hangers and supports, and other equipment items necessary to prevent overstressing the pressure containing parts.’

Thus, the ASME B31.4 standard is primarily for design and construction, not integrity management and operational standards. In addition to the dozens of other ASME codes for pipeline integrity management, B31Q for Pipeline Personnel Qualification sets standards for training and personnel qualification programs that address pipeline safety.

Shell has participated in ASME conferences, workshops, publications, and standards development for decades, and is thus well aware of such standards for oil pipelines.

3.3 U.S. Law on Integrity Management and High Consequence Areas

Pipeline Integrity Management

In the U.S., a system called *Integrity Management* (IM) was embodied May 29, 2001 in the U.S. Code of Federal Regulation (CFR) for managing pipeline integrity. The regulations entitled ‘Pipeline Integrity Management in High Consequence Areas’ (49 CFR 195.452) can be considered a global standard for pipeline safety and integrity. Kruprewicz 2007 concludes about the IM program that:

‘the minimum requirements defined in the U.S. Code of Federal Regulation for pipelines safety are leading this important effort in the world.’

Thus, as the U.S. IM regulations can be considered an international ‘good oil field practice’, an overview of what the IM standard requires is helpful in measuring the performance of Shell Nigeria against international best practice standards.

The U.S. IM regulations focus on protection for ‘High Consequence Areas’ (HCAs) that could be affected by a rupture. High Consequence Areas are defined as areas with high human population, navigable waterways, or environments unusually sensitive to oil spills (drinking water areas or productive ecosystems).

The Integrity Management program requires the following:

- Identification of all pipeline segments that could affect HCAs in the event of a failure;
- development of a Baseline Assessment Plan;
- criteria for remedial actions to address integrity issues raised by the assessment;
- a continual process of monitoring, assessment and evaluation to maintain pipeline integrity;
- identification of preventive and mitigative measures to protect HCAs;
- methods to measure the program’s effectiveness;
- a process for review of integrity assessment results and information analysis by a person qualified to evaluate the results.

And as stated above, the API 1160 standard published in November 2001 provides guidance

to all API members (including Shell) to implement the IM program, recommending that *all* pipeline segments be evaluated with a company's IM program, as follows:

Although the rule requires a Baseline Assessment Plan only for segments that could affect high consequence areas, an operator may find that such a plan is useful for its entire system, and could expand the scope of its program accordingly.

And, as Kruprewicz 2007 noted:

Many pipeline operators inspect considerably more of their transmission pipeline than the minimum required under current federal IM regulations.

As stated by the Administrator of the U.S. Pipeline and Hazardous Material Safety Administration (PHMSA) in March 2007:

As a result of the new IM program there have been 55,000 repairs of federally regulated pipelines in the last five years where problems were identified and fixed without incident.'

It is the author's judgment that most, if not all, of the Niger Delta meets the U.S. High Consequence Area (HCA) criteria (e.g. most of the Niger Delta should be considered a High Consequence Area for pipeline Integrity Management). Thus, in order to meet internationally recognized pipeline practices, as required by Nigerian law, all of Shell Nigeria's pipelines should have immediately been brought into conformance to the U.S. Integrity Management standard promulgated in May 2001.

The U.S. Integrity Management rule gave pipeline operators, including Shell, just 7 months (by Dec. 31, 2001) to identify all segments of their pipelines that could affect HCAs, and 11 months (by March 31, 2002) to complete their Baseline Assessment Plan.

The risk factors to be considered in the Baseline Assessment Plan include the following:

- Results of the previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate;
- Pipe size, material, manufacturing information, coating type and condition, and seam type;
- Leak history, repair history, and cathodic

protection history;

- Product transported;
- Operating stress level;
- Existing or projected activities in the area;
- Local environmental factors that could affect the pipeline (e.g. corrosivity of soil, subsidence, climatic);
- Geo-technical hazards; and
- Physical support of the segment, such as by cable suspension bridge, etc.

Under U.S. law, an operator must assess the integrity of their pipelines by several technical methods:

- internal pipe inspection tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves (smart 'Pipeline Inspection Gadgets', or 'PIGs');
- pressure testing;
- assessing weld seam integrity, especially for Electric Resistance Welded (ERW) pipelines
- external corrosion direct assessment;
- monitoring of cathodic protection
- other technologies that the operator demonstrates can provide an equivalent understanding of condition of the pipeline.

Further, U.S. Integrity Management law requires that pipeline operators must:

...continually change the program to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area.

Thus, Shell was required by the U.S. government to have completed a full Baseline Assessment Plan for all of its U.S. pipelines that could affect High Consequence Areas by March 2002, and knew at the time that this was the global 'good oil field practice' standard. And again, API Standard 1160 recommends that pipeline operators evaluate *all* of their pipeline segments with their Integrity Management program, not just those that transit HCAs. Shell is a member of API, and would have been well aware of all of their relevant standards.

Preventive and Mitigative actions required

A pipeline operator's Integrity Management evaluation and remediation schedule must pro-



vide for immediate repair conditions. To maintain safety and prevent spills in such situations, an operator is required to reduce operating pressure or shut down the pipeline until the operator completes the repair of specific risk conditions.

In the U.S. for instance, there were 1,350 pipeline conditions repaired or mitigated in 2005 on pipeline segments that could affect HCAs that were classified as needing 'immediate attention.' In addition, there were 6,000 other conditions repaired in that year requiring repair within 60 or 180 days. Appendix 3 below outlines the required repair schedule in the U.S. Integrity Management regulations.

It is important to note that as these are U.S. Integrity Management standards codified by API, these are considered international 'good oil field practice,' and are thus required of operators by Nigerian law as well.

Under the U.S. Integrity Management law, a pipeline operator must:

take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment or information analysis. In addressing all

conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline.

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A pipeline operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a High Consequence Area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. Such actions may include, but are not limited to:

- implementing damage prevention best practices,
- better monitoring of cathodic protection where corrosion is a concern,
- establishing shorter inspection intervals, and
- providing additional training to personnel on response procedures, conducting drills with local emergency responders and adopting other management controls, etc.

IM Leak Detection Systems

A critical component in reducing oil pipeline rupture / spill risk is a best available technology

Leak Detection System (LDS). The U.S. Integrity Management law requires an operator to have a means to detect leaks on its pipeline system, in particular for High Consequence Areas. The Leak Detection System should take into account the length and size of pipeline, type of product carried, the pipeline's proximity to a HCA, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results. Alaska law requires Best Available Technology (BAT) for all oil field components, including Leak Detection Systems (see section 3.4 below).

3.4 Additional requirements in Alaska USA

Best Available Technology (BAT)

In addition to the Integrity Management (IM) requirement in U.S. law, Alaska (where Shell does business as well) state law has stringent regulations that require petroleum companies to incorporate Best Available Technology (BAT) into all oil field operations – exploration, production, transportation, and storage, including pipelines and vessels hauling petroleum and petroleum products. The underlying statute requiring BAT to be incorporated in all petroleum operations in Alaska was first promulgated in 1980,

and was updated effective April 4, 1997 in AS 46.04.030(e), and the applicable regulations are at 18 AAC 75, Article 4, specifically 18 AAC 75.425(e)(4) and 18 AAC 75.445(k). As stated by the Alaska Department of Environmental Conservation's (ADEC) (Oil) Industry Preparedness Program (personal communication with Craig Wilson, ADEC Industry Preparedness Program Chief, October, 2007):

'In a nutshell, BAT applies to oil exploration, production, transportation, and storage, including pipelines and vessels.'

Alaska law stipulates that all oil spill prevention and contingency plans required in the state 'must provide for the use by the applicant of the best technology that was available at the time the contingency plan was submitted or renewed.'

With regard to the BAT requirement in Alaska law, the chief of Alaska's (Oil) Industry Preparedness Program stated (Craig Wilson, personal communication) the following:

'The concept of requiring "best industry practice" or "best achievable/available technology/practice" in oil production and transportation goes back decades. Most newer lease agreements for oil field

Friday Alfred Akpan from Ikot Ada Udo in Nigeria, a plaintiff in the court case against Shell about oil spills.



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development have some sort of “best industry practice”. Various European versions of BAT were proposed after the Torrey Canyon incident, and the IXTOC 1 blow out led to the development of “Best Available and Safest Technology” for the Minerals Management Service (MMS).’

The most recent Alaska BAT requirement stipulates that an oil industry BAT Conference is to be held every five years, the first of which was held in May 2004. Many technologies that could meet the BAT requirement were discussed at the conference.

Leak Detection Systems

As stated above, Alaska law requires Best Available Technology (BAT) for all oil field components, including Leak Detection Systems. The Alaska Department of Environmental Conservation’s Technical Review of Leak Detection Technologies for Crude Oil Transmission Lines states:

Early detection of a leak and, if possible, identification of the location using the best available technology allows time for safe shutdown and rapid dispatch of assessment and cleanup crews. An effective and appropriately implemented leak detection program can easily pay for itself through reduced spill volume and an increase in public confidence.

The Leak Detection System should incorporate continuous monitoring using such technologies as line-volume accounting, flow meters, pressure transducers, rarefaction wave monitoring, real-time transient monitoring, acoustic emissions, fiber optic sensing, vapor sensing, and aerial surveillance of remote pipelines. Alaska law requires effective alarm systems, and that the entire Leak Detection System be sensitive, accurate, reliable, and robust.

Best Available Technologies include such things as ATMOS pipe real time statistical analysis software, Supervisory Control and Data Acquisition (SCADA), duoThane hydrocarbon sensors, Leak-Net using Pressure Point Analysis that can detect leaks as small as 4.5 parts per million of line volume, WaveAlert, Ultrasonic Flowmeters, Line-Volume Balance accounting, etc. It was not possible to determine which of these technologies, if any, Shell employs in its Nigeria pipeline operations.

The Alaska Technical Review details methods used to detect product leaks along a pipeline,

which it divides into two categories – externally based (direct) or internally based (inferential). Externally based methods detect leaking product outside the pipeline and include traditional procedures such as right-of-way inspection by pipeline patrols, as well as technologies like hydrocarbon sensing via fiber optic or dielectric cables. Internally based methods, also known as Computational Pipeline Monitoring (CPM), use instruments to monitor internal pipeline parameters (i.e., pressure, flow, temperature, etc.), which are inputs for inferring a product release by manual or electronic computation.

The Alaska Leak Detection System Review suggests that the chosen Leak Detection System should include as many of the following desirable leak detection characteristics (from API CPM 1995) as possible:

- accurate product release alarming;
- high sensitivity to product release;
- timely detection of product release;
- efficient field and control center support;
- minimum software configuration and tuning;
- minimum impact from communication outages;
- accommodates complex operating conditions;
- configurable to a complex pipeline network; performs accurate imbalance calculations on flow meters;
- is redundant;
- possesses dynamic alarm thresholds;
- accommodates product blending;
- accounts for heat transfer;
- provides the pipeline system’s real time pressure profile;
- accommodates slack-line and multiphase flow conditions;
- accommodates all types of liquids;
- identifies leak location;
- identifies leak rate;
- accommodates product measurement and inventory compensation for various corrections (i.e., temperature, pressure, and density); and
- accounts for effects of drag reducing agent.

Shell participated in the Alaska technical review of Leak Detection System technology for pipelines, and was thus well aware of such technological development long ago. Again, as these Leak Detection System standards are codified by API, these are considered international ‘good oil field practice,’ and are thus required of operators by Nigerian law as well.

Post-Exxon Valdez oil spill response planning

The 1989 Exxon Valdez Oil Spill in Alaska prompted a dramatic improvement in oil spill prevention and response preparedness in Alaska, the U.S. and elsewhere in the world. Today, the spill prevention and response system implemented in Prince William Sound, Alaska is internationally recognized as a good practice for spill response planning. The government contingency plan requirements stipulate that all companies transporting oil in this region meet a Response Planning Standard whereby they would be capable, with equipment and personnel on-hand, of cleaning up a 300,000-barrel (40,000 ton) oil spill within 72 hours (3 days). As well, the companies must have a plan to respond to a potential worst-case discharge, which is set at 1 million barrels (140,000 tons) for this region. This worst-case spill response plan allows the company to rely on equipment outside the immediate vicinity, but it must be readily available. The pipeline operators must demonstrate that they have the equipment, trained personnel, command structure, etc. to meet these Response Planning Standards.

To meet this standard, the pipeline owner / operator established the *Ship Escort Response Vessel System (SERVS)* in 1990, which is internationally regarded as one of the top oil spill response forces in the world. Today, the SERVS system costs the pipeline owners/operators about \$60 million USD / year to maintain and operate. SERVS has over 200 trained personnel on staff 24/7/365, and another 60 people on the pipeline company's crisis management team (PWS RCAC, 1999). Response resources on-hand to meet their RPS include over 35 miles of containment boom, 100 oil skimmers with a total capacity to recover 75,000 barrels of oil / hour, storage barges with a total capacity of over 34 million gallons, pumps, fire boom, etc. The spill response system is continually tested with drills at least once every year, both announced and unannounced. Some 300 local fishermen and vessels are trained in spill response and under contract to provide spill response service if needed. And an oiled wildlife response unit is on standby.

Each company that operates is required to have a government approved Oil Spill Contingency Plan (OSCP). Shell is not now an owner of the Alaska pipeline, but would ship oil through it in the future, and is thus well aware of and will par-

ticipate in this spill response system. Note that this response capability is in place for one terminal in Alaska, and there are 10 terminals in the Niger Delta, with far less capability collectively.

Shell Beaufort Sea Exploration Oil Spill Contingency Plan

Other spill response capability in Alaska relates perhaps more directly to Shell. In 2007, Shell Offshore Inc. received permits from the U.S. government to conduct its proposed 2007 – 2009 Beaufort Sea oil and gas exploration program in the Arctic Ocean off Alaska. In conjunction with this plan, Shell submitted in January 2007 its *Beaufort Sea Regional Exploration Oil Discharge Prevention and Contingency Plan*, which was approved by the U.S. and Alaska government. As this area is considered a very sensitive environment, and a High Consequence Area (HCA) for oil spills, there was a great deal of public, industry, and government scrutiny to the Oil Spill Contingency Plan (C-Plan) process. As a result of such scrutiny, Shell's 2007 Beaufort Sea Exploration C-Plan (Shell BSE C-Plan) was well developed, and reflects a clear and comprehensive understanding within the company of practices with regard to oil spill response planning. It is important to note that this C-Plan is just for an exploration program, not a production or transportation program.

As with other C-plans in the U.S., federal regulation requires the operator to review the plan annually (33 CFR Part 154), and renew the plan every two years with the federal government (30 CFR Part 254.30). The Shell BSE C-Plan contains emergency notification checklists and procedures, a specified command structure, emergency communication plans and equipment identified, specified equipment and personnel deployment strategies, pre-staged equipment, blow out control strategies, spill tracking, and protection of sensitive areas. Spill containment and recovery equipment on-site includes two Oil Spill Response Vessels (OSRVs) each with a minimum 12,000-barrel storage capacity, with two skimmers, and mini barges on board. As well, there is a back-up, bulk storage oil tanker with 513,000 bbl capacity standing by on-site to store any recovered oil that may spill. Though just an exploration program, the worst-case spill scenario planned for is a 5,500 bbl/day well blow out. The C-Plan also includes a thorough near-shore and shoreline response plan.



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3.5 Intentional Third Party Damage (sabotage / illegal bunkering)

In addition, pipeline 'good oil field practice', including the Integrity Management system, requires operator attention to the potential for Third Party Damage (TPD). In much of the world, this normally implies accidental TPD, such as construction equipment accidentally rupturing a buried pipeline, etc. But clearly in the Niger Delta, intentional TPD - sabotage and illegal bunkering - is a legitimate concern, and should be considered a high priority in pipeline Integrity Management programs.

Sabotage and theft is a problem for oil pipeline operators in several regions around the world, notably Mexico, Columbia, the Middle East, Asia, and Africa. There has been a great deal of industry and government experience with pipeline sabotage, and much has been learned about sabotage prevention and detection, particularly since the 9/11 terror attacks in the U.S. and the risk to oil infrastructure in Iraq during the Iraq war.

Common Ground Alliance

The Common Ground Alliance (CGA) in the U.S. is a non-profit organization dedicated to the promotion of shared responsibility and implementation of 'best practices' in pipeline damage prevention, largely accidental damage (CGA 2008). The CGA developed from a Common Ground Study sponsored by the U.S. DOT on Damage Prevention Best Practices in 1999. The Study and subsequent CGA stipulate Best Practices for pipeline operators in preventing TPD, including planning and design criteria, notification, pipeline locating and marking, excavation, mapping, public education, reporting and evaluation, and security best practice.

API standards

The American Petroleum Institute (API), in connection with the U.S. Department of Homeland Security developed guidelines after the 9/11 terror attacks in the U.S. to help pipeline operators protect their facilities from terror attacks and vandalism (API 2003, API 2004). The documents provide recommended practice and standards to protect from theft, vandalism, and terror attacks. In the post-9/11 security environment in the U.S., petroleum companies have re-assessed their vulnerabilities to such international TPD, and implemented much more stringent measures.

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Management of sabotage risk in an Integrity Management program

Taking into account the threat of Intentional TPD / sabotage in an operating area, particularly one with such security risk as the Niger Delta, it is reasonable to expect an operating company to evaluate and incorporate into their Integrity Management program rigorous safety measures designed specifically to mitigate this threat. These additional sabotage prevention measures should include such things as more robust Design Factors including sabotage resistant pipe specifications, thicker walled pipe, reduced D/t ratio (pipe diameter / pipe wall thickness), higher grade steel, pipe-in-a-pipe or pipe-bundle technology, etc.; alternate choices for routing pipelines away from high-risk areas; deeper burial of underground pipeline segments; concrete casements around pipe; more rigorous and frequent inspection protocols; enhanced Leak Detection Systems with greater sensitivity; better community engagement; and other traditional security techniques.

A crucial component of pipeline sabotage prevention system is *enhanced pipeline surveillance*. Pipeline surveillance regimes can include remote closed-circuit television cameras, fibre-optic sensor technology along the entire length of the pipeline, more frequent aerial patrols, remote listening devices (e.g. hydrophones, etc.) to detect drilling, digging, tapping, engine noise, explosions; satellite imaging; and so forth. Additional technologies that should be considered for Nigeria include the Westminster DDS-J Diver Detection Sonar system that scans a distance underwater of 1 km / node, 25 m on each side and 50 m vertically, has hydrophones to detect any disturbance, and sounds an alarm when a disturbance occurs in the scanned area. As well, fibre-optic cable sensors can detect digging, tapping, or other disturbance, with one sensor capable of scanning a 40 km pipeline segment. Once an enhanced surveillance system is implemented, a robust public information campaign to inform local residents that enhanced security is in place will act as a deterrent to sabotage and illegal bunkering.

3.6 Conclusions

The discussion above briefly summarizes the author's assessment of internationally recognized 'good oil field practice.' The report focuses on critical petroleum system components that are most relevant to oil spills in the Niger Delta: pipeline integrity; sabotage (TPD) prevention; oil spill response.

The development of standards and regulations for pipeline integrity globally has followed those developed in the United States. The U.S. system, called Integrity Management (IM), is required by law and is used around the world as the international 'best practice' standard to meet. In Alaska, additional requirements exist, namely that 'Best Available Technology' (BAT) must be applied in all oil and gas operations.

Internationally recognized standards for oil pipeline management are, among others:

- API 1160 (American Petroleum Institute) which provides guidance to implement the Integrity Management (IM) program for High Consequence Areas.
- ASME B31.4 (American Society of Mechanical Engineers) standard for design and construction of pipelines
- API 1130 standard for pipeline Leak Detection Systems.

As most parts of the Niger Delta meet the criteria defined in the U.S. as High Consequence Areas for oil spills (populated area, drinking water area, or productive ecosystem), oil companies in the Niger Delta are implicitly required by Nigerian law to comply with the API standards for High Consequence Areas. In addition to being a High Consequence Area, the Niger Delta is an area susceptible to damage from third parties (sabotage, illegal bunkering). The American Petroleum Institute (API) has developed guidelines to protect operators from the risk of terror attacks and vandalism. To be in compliance with Nigerian law requiring international standards, oil companies in the Niger Delta must meet this standard.

With regard to oil spill response, two models - both in Alaska, USA - serve as 'good oil field practice' by which to compare performance of Shell in the Niger Delta.

4. Performance by Shell Nigeria

4.1 Shell in Nigeria

Two Shell companies, both subsidiaries of Royal Dutch Shell based in the Netherlands, operate in Nigeria to produce oil: The Shell Petroleum Development Company of Nigeria Limited (SPDC) and Shell Nigeria Exploration and Production Company (SNEPCo). While SNEPCo is mostly responsible for Shell operations offshore, SPDC is mostly responsible for onshore operations. SPDC is the largest private-sector oil and gas company operating in Nigeria. Shell Nigeria is capable of producing an average of one million barrels of oil equivalent per day, almost half of Nigerian oil production.

SPDC is the operator of the joint venture between the Nigerian government, through the Nigerian National Petroleum Corporation NNPC (55%), Shell (30%), Elf Petroleum Nigeria Limited (a subsidiary of Total, 10%), and Agip (5%). SPDC's operations in the Niger Delta are spread over some 30,000 square kilometres and include a network of over 6,000 kilometres of flowlines and pipelines, 90 oil fields, 1,000 producing wells, 73 flow stations, eight gas plants and two major oil export terminals at Bonny and Forcados. (Shell 2008a)

4.2 Oil spill history of Shell Nigeria

Period 1989-1994

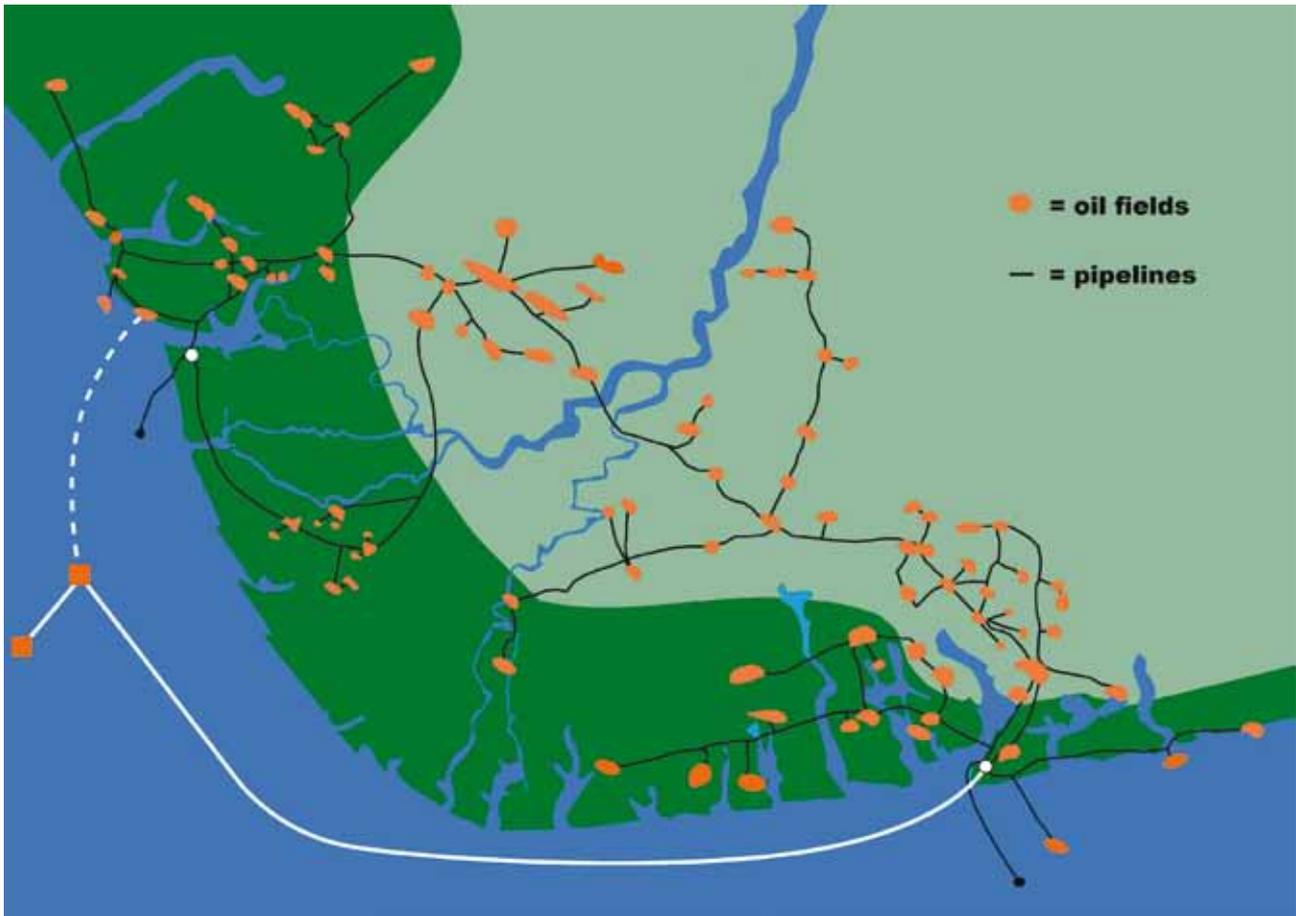
Shell Nigeria, in the period 1989-1994, reported an average of 221 oil spills per year in its operational area, involving a total of some 7,350 barrels of oil a year. Shell reports that about half of the volume spilled in this period was due to corrosion of ageing facilities, mostly flow lines. Shell reports that 21 per cent of spills in this period were during production, while 28 per cent were due to sabotage. (Shell 1995)

The following table shows that the pipeline failure rate in Nigeria is many times that found elsewhere in the world. In the period 1976-1995 the oil companies in Nigeria operated well below international standards. In that period Shell Nigeria accounted for about half of Nigerian oil production.

In 1996, Bopp van Dessel, the former head of environmental studies for Shell Nigeria from 1992 to 1994, revealed his concern regarding the poor environmental practices of Shell Nigeria (IPS 1996, Haznews 1996). Van Dessel quit Shell in 1994

Comparison of World-Wide Pipeline Failure Rates (PPSA 2004)

Region	Product	Failure rate, per 1000 km-years	Year
United States	Gas	1.18	1984-92
United States	Oil	0.56-1.33	1984-92
Europe	Gas	1.85	1984-92
Europe	Oil	0.83	1984-92
Western Europe	Oil	0.43	1991-95
Western Europe	Gas	0.48	1971-97
Canada	Oil & Gas	0.35	N/A
Hungary	Oil & Gas	4.03	N/A
Nigeria	Oil	6.40	1976-95



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because of 'professional frustration'. He stated that Shell had 'consistently ignored internal warnings' that its operations in Nigeria 'breached international standards and caused extensive pollution', and:

'Wherever I went, I could see that Shell were not operating their facilities properly. They were not meeting their own standards, they were not meeting international standards.' 'Any Shell site that I saw was polluted, any terminal that I saw was polluted. It is clear to me that Shell was devastating the area.'

To reduce and manage spills, Shell Nigeria (Shell 1995) established a programme to:

- Replace and upgrade ageing facilities and pipelines to meet the latest safety and environmental standards.
- Improve the way it operates, maintains facilities, and responds to spills.
- Work more closely with communities.

Period 1998-2009

While some improvements may have been made by Shell Nigeria subsequent to the 1989-1994 period, several figures and statements in Shell

reports show that its oil spill record in Nigeria still has not been satisfactory, and pipeline integrity and oil spill response is not consistent with international standards for 'good oil field practise'.

1) Controllable oil spills show no decline

Shell Nigeria uses the terms 'operational' or 'controllable' for oil spills that are within its 'control to prevent' (non-sabotage) and due to 'failure of equipment, corrosion or human error' (Shell 2008a). Compared to the period 1989-1994, the period 1998-2007 reflected no decline in the volume and amount of controllable oil spills by Shell Nigeria, as the following table shows:

2) Nigeria represents disproportionate percentage of oil spilled by worldwide Shell-group

Shell Nigeria represented 61 per cent of the total volume of oil reported spilled within the Shell-group in the period 1998-2009 (see appendix 1). In the period 2003-2009, about 15 per cent of the total crude oil and natural gas liquids production of the Shell-group worldwide originated from Nigeria (Shell 2008b). Thus, Shell Nigeria is responsible for a disproportionate percentage of oil spilled by the worldwide Shell-group.

3) Lack of funds dedicated by Shell Nigeria to pipeline integrity

Shell has confirmed several times that not enough money is spent to ensure the condition of pipelines and other assets in Nigeria. The EP-Businessplan 2000 of the Shell-group states about the operations in Nigeria (Shell 2000):

‘Significant funds will be required to maintain and upgrade SPDCs vast infrastructure, including the major refurbishment of Bonny terminal.’

In the Sustainability report 2006 of the Shell-group, Basil Omiyi, former managing director of Shell Nigeria states (Shell 2007c):

‘We do, however, have a substantial backlog of asset integrity work to reduce spills and flaring. That backlog is caused by under-funding by partners over many years, operational problems and, more recently, the lack of safe access to facilities.’

See discussion of this issue below in Section 4.7 regarding the problematic relationship between Shell and the government of Nigeria.

4.3 Pipeline integrity within Shell Nigeria

Background

It was not possible with the information available to provide a thorough analysis of Shell Nigeria’s performance in comparison to internationally recognized ‘good oil field practise’ for pipe-

line integrity (see Transparency section below). Such an analysis would require a detailed engineering review of the entire pipeline system of Shell Nigeria, in particular the 2003/2004 Asset Integrity Review, their system rehabilitation master plan, the resulting Pipeline Integrity Management System (PIMS), inspection protocols, pipeline routing, Design Factors for the system, operator personnel training and staffing levels, system anomalies (overpressure events, etc.), spills, and so forth. Such a review would also include confidential interviews with many current and former SPDC employees, managers, and contractors.

However, even without conducting such a thorough evaluation, some conclusions can be drawn. Clearly, Shell has been, or should have been, well aware of Best Available Technology (BAT) and Integrity Management systems for some time. As such requirements date back many years, a company with the experience and global reach of Shell would certainly be aware, if not directly involved in the development, of such technological and regulatory processes as they evolved. At a minimum, Shell should have been clearly aware of the many API standards (e.g., the Leak Detection System standard established in 1995), ASME standards, the Alaska BAT requirement in 1997, and the U.S. Integrity Management requirement in 2001.

The annual reports of Shell Nigeria contain some information about its pipeline integrity management program. Certain statements in the reports (below) call into question the extent to which its pipeline integrity is consistent with internationally recognized standards:

Shell Nigeria, oil spill statistics per year during three periods

Region	Average amount oil spills	Average volume oil spills (barrels)	Volume due to controllable spills	Volume due to sabotage spills
Period 1989 – 1994 (Shell 1995)	221	7.350	5.300	2.050
Period 1998 – 2007 (see appendix 1)	272	28.433	11.673	16.760
Period 1998 – 2002 (see appendix 1)	293	40.238	18.148	22.089
Period 2003 – 2007 (see appendix 1)	250	16.628	5.196	11.432
Period 2008 – 2009 (see appendix 1)	220	41.491	12.020	29.452

The author (and other observers) feels that Shell Nigeria’s reporting of spill numbers and volumes represents a significant under-reporting of the actual spill frequency and volume.

- Shell Nigeria reported in its 2005 annual report that 'a corrosion sampling campaign was launched in 2005 that will lead to an (corrosion) inhibition programme for SPDC's onshore oil and gas lines in the coming years.' Given that pipeline corrosion inspection and inhibition protocols have been established internationally for decades, that Shell Nigeria did not initiate such a comprehensive program until 2005 shows it has not acted with due diligence in improving pipeline integrity.
- In their 2003 annual report, Shell Nigeria states that 'internal obstructions in the pipelines have prevented some lines from being subjected to these internal inspection or cleaning operations.' Although such in-line obstructions pose a known risk of over-pressure events and catastrophic rupture, the report gives no further analysis of these obstructions or any plan to remedy this very dangerous condition.
- Almost every year Shell Nigeria reports spills due to corroding main pipelines. In 2007 there was a spill 'along a 28-inch pipeline in the Cawthorne Channels due to corrosion.' In 2006 the Nembe-IV pipeline spilled about 2.500 barrels of oil. In 2005 Shell Nigeria reported that 'the number of spills caused by corrosion decreased slightly from 38 in 2004 to 33 in 2005'. In 2004 leaks, caused by corrosion, were reported from an 8-inch line near Opuama, the 24-inch Nkpoku to Bomu line and the 12-inch Imo River I line. In 2003 Shell Nigeria reported a leak in the 28-inch Trans Niger Pipeline (TNP) along Rukpokwu, to have resulted from 'a tear at the bottom of pipe, most likely due to internal corrosion.' By comparison, the Trans Alaska Pipeline in the U.S. has operated for over 30 years with no corrosion related spills reported (Alyeska Pipeline Service Company).

In a meeting with the author on June 4, 2007 in Port Harcourt with Mr. Basil Omiyi, Country Chair of Shell Nigeria and then still Managing Director of SPDC, Mr. Omiyi admitted that SPDC's pipeline replacement program was far behind schedule. And although he blamed this on the Nigerian partners and the militancy problem, these are not sufficient excuses in the author's judgment.

Shell Nigeria Asset Integrity Review 2003/2004

In 2003 Shell Nigeria initiated an Asset Integrity Review, which was concluded in 2004 (Shell 2004a):

'2004 saw the conclusion of a major review programme, which was initiated in 2003 to conduct a comprehensive assessment of our asset integrity management systems (covering wells, pipelines, flowlines and other production facilities). The review was intended to ensure compliance with required standards for the specific equipment whilst also supporting the drive for performance improvement. The review established the current physical condition of the assets and identified the scope and scale of work required to bridge the existing gaps.'

Shell Nigeria reports that it did not initiate their Asset Integrity Review until 2003 / 2004, indicating a systemic lack of urgency within Shell for bringing its Nigeria operations up to generally accepted international standards for 'good oil field practise'. Considering that several significant spills and system anomalies occurred on main trunk-lines after the SPDC Asset Integrity Review and the initiation of the Pipeline Integrity Management System (PIMS), the quality and thoroughness of the Asset Integrity Review and PIMS seems questionable. At very least, Shell Nigeria should have commenced its Asset Integrity Review and PIMS as soon as possible after such a process became required for its U.S. pipeline operations (2001), certainly well before 2004. Had a competent Asset Integrity Review (or Baseline Assessment Plan), replacement program, and PIMS been implemented in 2001 - 2002, it is likely that subsequent large pipeline spills would have been averted.

Pipeline Integrity Management System (PIMS)

Part of the Asset Integrity Review from 2003/2004 was the introduction of a Pipeline Integrity Management System (PIMS). The Shell Nigeria 2004 annual report states:

'The resulting SPDC Pipeline Integrity Management System (PIMS) involves a suite of activities required to properly manage the asset, assure asset integrity, fulfil health, safety and environmental

(HSE) requirements, and deliver optimum life cycle performance. The SPDC PIMS is in line with the relevant American Standard for Mechanical Engineers (ASME) B31.8s, adapted to the local environment and supplemented with pipeline management experience from the Royal Dutch/Shell Group. As part of PIMS, a maintenance reference plan has been developed that is tied to the condition of the line. Thus, depending on the monitored condition of the lines, the frequency of maintenance actions is either increased or decreased - rather than being carried out at preset intervals.'

A few observations are in order regarding Shell Nigeria's Pipeline Integrity Management System (PIMS):

- PIMS is a management plan – its existence does not necessarily mean it has been implemented.
- PIMS was developed late. As stated above, Shell has been well aware of Best Available Technology (BAT) and Integrity Management systems for some time. And as such requirements date back decades, a company with the experience and global reach of Shell would certainly be aware, if not directly involved in the development, of such technological and regulatory processes as they evolved. At a minimum, Shell should have been clearly aware of the many API standards (e.g., the Leak Detection System standard established in 1995), ASME standards, the Alaska BAT requirement in 1997, and the U.S. Integrity Management requirement in 2001.
- The Shell Nigeria 2004 annual report states that the SPDC PIMS 'is in line with the relevant American Society of Mechanical Engineers (ASME) B.31.8s', which is the gas transmission line standard. The report does not reference the ASME B.31.4 standard that applies to oil transmission lines, or the API standards for Integrity Management, as also required under Nigerian law.
- PIMS was apparently applied only to high-pressure pipelines only. The Shell Nigeria 2004 annual report states Shell operates 3,000 km of pipelines, but also states it has 5,000 km of (low- pressure) flow lines. Shell Nigeria has reported it has yet to develop an integrity management system for its extensive network of flow lines. The Shell Nigeria 2004 annual report states:

'The learning gained from PIMS will be employed in developing flow line integrity programmes, leading to an integrity management system for our network of some 5,000 km of flow lines in the next two to three years.'

On PIMS, the Deputy Managing Director of SPDC stated (e-mail from Mike Corner to Clive Wicks, member of the IUCN/CEESP Commission, June 2006) the following:

'In SPDC the replacement of pipelines is based on the integrity status and not on the age of the pipeline. (. . .) The integrity status of the line is determined through the SPDC Pipeline Integrity Management System (PIMS) which was created in 2004 and is aligned with international and Shell group standards. In 2003, a review of the integrity of all the trunk lines was undertaken and several pipelines were identified for replacement; e.g. the Nembe Creek Trunk Line and the Kolo Creek to Rumuekpe Trunk Line are currently being replaced.'

Kolo Creek to Rumuekpe Trunk Line

While replacement had been scheduled in 2003 for the Kolo Creek – Rumuekpe Trunk Line, it did not actually take place as scheduled. This pipeline segment ruptured in June 2005 causing a major oil spill at Oruma. SPDC's delay in replacing this pipeline segment, which they had identified as in immediate need of replacement, likely constitutes negligence on the part of the company, in the author's judgment. This is underlined by a description of the pipeline in the Executive summary of an Environmental Impact Analysis that SPDC made public in 2010. (SPDC 2004)

The current operational 20" x 38km Kolo Creek - Rumuekpe T/L, a carbon steel pipeline, was commissioned in December 1994 to replace an existing corroded 20" line commissioned in 1974. The 1974 line was flushed and mothballed after decommissioning. The current line evacuates approximately 102,000 bopd from Diebu Creek, Nun River, Kolo Creek, Etelebou, Gbaran and Enwhe fields to the Rumuekpe pipeline manifold.

The first intelligent pigging inspection of the replacement line (February 1996) indicated extensive and severe wall loss (up to 55%). The corrosion patterns were similar to those seen in the corroded and mothballed line with an indicated corrosion rate of >4mm/yr. The wall loss was

confirmed by manual ultrasonic inspection. Thereafter the pigging frequency was increased to twice monthly. A second inspection (November 1996) indicated more extent of corrosion with wall loss of over 80% in some sections but the corrosion rate reduced to 0.6mm/yr. Semi-automated ultrasonic inspections carried out in 1997/98 confirmed the rate.

Need for the Project

The corrosion was deemed “unmanageable” by a recent engineering study carried out on the line in 1999. The study however recommended pulling in a 14” Steel strip laminated GRE pipe into the existing pipeline. The use of this material in the nearest future cannot be guaranteed due to size constraints 14” is the minimum size that could be pulled into a 20” steel pipe. Failure of the GRE material during pre-qualification test for the intended service and the fact that recent inspection of the existing line indicates that the corrosion rate continues unabated and that the line is likely to leak before the year 2003/2004 informed the decision to replace the line with carbon steel pipes with adequate provision for frequent pigging and biocide injection.

When the author visited the site in 2007 the segment had still not been replaced, and the replacement pipe was still pre-staged along the right-of-way. In 2009 the pipe was finally replaced.

Nembe Creek Trunk Line

The contractor Nestoil (Nestoil 2008) of Shell Nigeria, replacing a 49 kilometer 24-inch Nembe Creek Trunk Line from the Nembe 3 flowstation to San Bartholomew manifold, states on its website the following about the replacement project:

‘As a result of deterioration in the integrity of the existing trunkline, occasioned by the harsh Niger Delta environment, vandalism and severe age-related deterioration, the project was initiated to improve, modernize and restore the technical integrity of the facilities.’

In its annual report of 2006, Shell Nigeria reports an accidental leak, caused by the contractor laying the new pipeline along the old one. Thus, in 2006 the pipeline was not replaced yet. The other part of the Nembe Creek Trunk Line, connecting the San Bartholomew Manifold with the Cawthorne Channel Junction Manifold Trunkline, was planned (Reuters 2007) to be replaced in the third quarter of 2008. In 2010 the replace-

ment was finally completed. SPDC made the following announcement on its website.

SPDC Joint Venture Replaces Major Pipeline . The Shell Petroleum Development Company of Nigeria (SPDC) joint venture is close to completing the construction of a major \$1.1-billion oil pipeline in the Niger Delta as part of the ongoing programme to keep its facilities well maintained. The new 97-kilometre Nembe Creek Trunkline will have a capacity to transport 600,000 barrels per day from 14 flowstations in the Niger Delta to the Bonny export terminal in Rivers State. With half of the line so far commissioned, it is taking the place of an existing pipeline scheduled for replacement. www.shell.com.ng

Other main pipelines

In 2004, Shell Nigeria (IAIA 2004) reports that a major trunk line replacement project has been proposed for the eastern division of SPDC with pipeline leading to the Bonny terminal. The project involved the 104 km Nembe Creek Trunk Line (NCTL), the 89 km Greater Port Harcourt Swamp Line (GPHSL) and the 274 km Trans Niger Pipeline (TNP). Except for the Nembe Creek Trunk Line, Shell Nigeria has not reported anything since 2004 about possible proceedings on the replacement of these main pipelines. The author has no knowledge that they have been replaced.

4.4 Lack of transparency in pipeline integrity management

The above discussion demonstrates that the pipeline integrity management of Shell Nigeria has experienced significant problems and is not consistent with international standards of API and ASME.

The author attempted, unsuccessfully, to access information to further examine the efficacy of Shell Nigeria’s pipeline management. Even though the *Shell General Business Principles* (Shell, 1997) state that Shell will ‘provide full relevant information about their activities to legitimately interested parties’, their actions are inconsistent with such a professed transparency principle.

In e-mails dated June 12, 2007 and October 6, 2007 from the author to the Director of Shell

Nigeria copied to the CEO of Shell in the Hague, the author requested a copy of the Shell Nigeria / SPDC Oil Spill Contingency Plan (OSCP) for review. There was no reply. In an e-mail dated October 17, 2007, the author asked Shell in addition for the Joint Operating Agreement, and a copy of the Shell Nigeria Asset Integrity Review. These document requests were made in order to compare Shell's planning with their actual performance.

In December 2007, Shell's Regional Director Communications Africa, replied (Shell 2007b):

'The Asset Integrity Reviews are internal Shell operating documents designed to provide information on the state of our assets and improvements that are necessary - and are regarded as strictly confidential and business sensitive.'

In 2004 the organisation Christian Aid also tried to obtain information on the condition of the pipelines of Shell Nigeria. Shell promised to provide some information from its annual reports, but this was never done. In the report from

Christian Aid, Andrew Palmer, research professor in petroleum engineering at Cambridge University, stated (Christian Aid 2004):

Today, most pipelines are designed for a lifetime of about 40 years. Design, materials and construction standards, and technology, have changed a great deal since the 1960s, however, and if issues regarding the lifetime of pipelines are raised, responsible operators have nothing to hide and should apply the maximum transparency. That's the position taken in countries such as the US and Canada with high standards of freedom of information.'

Independent analysis

Without thorough independent analysis of the Shell Nigeria Asset Integrity Review and the Pipeline Integrity Management System, it is difficult to judge their adequacy. The U.S. government, through the Pipeline and Hazardous Material Safety Administration (PHMSA) has a rigorous program to certify pipeline operator

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compliance with the IM requirement, but it is evident that there is no such independent, rigorous program that certifies compliance in Nigeria. Without such a thorough, independent, technical analysis of the SPDC Asset Integrity Review and the Pipeline Integrity Management System, it is impossible to judge the extent to which these meet the U.S. IM protocol from 2001, or the Nigerian government's requirement to meet 'good oil field practise.'

Shell (Shell 2004b) states it supports objective third-party assessment of its programs for asset integrity management:

Whether companies operate in Venezuela, Nigeria or France, they should have a program for managing the integrity of their assets for the protection of their investments. An objective third-party assessment by a consultant who can call on a vast operation experience can be an invaluable part in the development of such a program.

As far as the author knows, such an independent analysis of the Shell Nigeria Asset Integrity Review and PIMS has yet to be conducted. Given the state of development of 'good oil field practise' with regard to pipeline manage-

ment (particularly the U.S. Integrity Management regulations, API standards, and Alaska's Best Available Technology requirements), Shell's knowledge of such, the delay in initiating the SPDC Asset Integrity Review and PIMS, the questionable adequacy of the Asset Integrity Review and PIMS, the delay in the Kolo Creek-Rumuekpe Trunk Line replacement, and the dismal track record of pipeline spills in the Niger Delta before, during, and after the Asset Integrity Review/PIMS, it can be concluded that Shell Nigeria continues to operate far below the internationally recognized standards for pipeline management.

4.5 Oil spill response by Shell Nigeria

The historical record of Shell's response to oil spills in the Niger Delta shows that the company employs a much lower standard with respect to oil spill response in Nigeria than elsewhere. In extensive site-visits conducted in 2006 (IUCN/CEESP 2006), the author and colleagues witnessed many sites of spills from Shell oil infrastructure which Shell had either not responded to at all, or had responded in a highly ineffective manner. Many of the sites remained extensively polluted. We met with many village chiefs and

residents who related similar stories of a lack of spill response from Shell when there had been spills from infrastructure Shell Nigeria operates in their area.

A typical spill response profile for Shell in the Niger Delta region is as follows:

A spill occurs from a corroded or over-pressured pipeline rupture or poorly maintained flow station; the spill is only detected and reported by a nearby village resident (not by any Leak Detection System or other means by Shell); Shell visits the site a day or more later; Shell then takes several more days or weeks to mount a very limited response, if indeed they mount one at all; meanwhile, the oil continues spilling into the local environment, contaminating freshwater systems and farm lands; villagers become angry at the delayed response, and Shell later alleges that they were restricted from accessing the site due to security concerns; little if any oil is actually recovered from the environment; Shell participates in a Joint Inspection Team (JIT) investigation with the federal government, state government, and a local village representative; Shell dramatically under-estimates the spill volume, and blames the pipeline failure and subsequent spill on sabotage; Shell asks villagers to sign documents releasing the company from liability, and compensates villagers who sign the release with meagre financial support; no environmental damage assessment is conducted, and no restoration is attempted; Shell and the government terminate their involvement.

According to the Environmental Guidelines and Standards for the Petroleum Industry of the Nigerian government (NG-EGASPIN 2002) Shell Nigeria must have an Oil Spill Contingency Plan (OSCP). This plan needs to describe in detail how the company will respond to oil spills from its facilities, whether caused by sabotage or not. Again, the author requested but was not provided a copy of Shell Nigeria's OSCP.

However, it is evident that whatever their OSCP asserts with regard to SPDC readiness to respond to oil spills in the Niger Delta, the company's actual performance in oil spill response in-region is far below the internationally recognized standards as described above.

4.6 Shell Nigeria's lack of compliance with EGASPIN

Environmental Guidelines And Standards for the Petroleum Industry in Nigeria (EGASPIN) was first promulgated by Nigeria's Department of Petroleum Resources (DPR) in 1991, and further revised in 2002. The following analysis compares SPDC performance with the most recent (2002) EGASPIN requirements.

II. Exploration and Development Operations

E.3.6.1 *'It shall be mandatory for a licensee or leasee to conduct an EIA (Environmental Impact Assessment) for every development activity, such as: onshore and nearshore drilling; construction of flowlines, delivery lines, and pipelines in cumulative excess of 20 kilometers in length; construction/installation of flowstations, production stations (production platforms/FPSO).'* (as also mandated in VIII.A. below)

It is unclear to what extent SPDC has complied with this EIA requirement.

VI. Oil and Gas Transportation

3.2.1 *'All pipelines and flowlines for crude and petroleum products including gas shall be patrolled and inspected, once in every month or otherwise as approved by DPR.'*

It was impossible to determine the extent to which this has been complied with, but with over 3,000 km of main pipelines in the region, and 5,000 of low-pressure flowlines, the author feels that it is unlikely that Shell is in full compliance with this monthly inspection requirement. It is also not possible with existing information to say whether DPR has granted SPDC any exemptions to this monthly inspection requirement.

3.2.2 (v) *monthly inspection of all pipelines and flowlines is to include 'corrosion monitoring indications and measurements.'*

Again, with the thousands of km of buried pipelines, the primary method for inspection is internal inspection devices (smart Pipeline Inspection Gadgets, etc.), and it is difficult to know the extent of compliance of Shell Nigeria with this requirement.

VIII.A. Environmental Impact Assessment Process

Nigeria law requires both an *Environmental Impact Assessment (EIA)* for newly proposed development and an *Environmental Evaluation (EE)* for already polluted or impacted environments. The EIA Report is required to assess 'all actions that will result in a physical, chemical, biological, cultural, social, etc. modification to the environment as a result of the new project/development.' The EE Report (EER) is required to evaluate 'already 'polluted' or impacted environments to enable the government to know how 'good' or 'bad' (i.e. state of the environment) the recipient environment is so as to decide and design strategies for protection and restoration.'

1.6 (iii) Requires an EIA for 'laying of crude oil and gas delivery lines, flowline and pipeline in cumulative excess of 20km length and/or as determined by the Director of Petroleum Resources.'

2.1 (i) Requires an EER for activities that have 'been observed to cause significant and adverse environmental effects and impact...spillages of oil or hazardous materials/wastes are under this category.' Thus, for all oil spills, particularly Tier II and III spills, the operator is required to conduct a scientific post-spill Environmental Evaluation.

2.2 Requires that the EER shall contain a full description of the spill incident, qualitative and quantitative descriptions of the already impacted environment, loss of and significance of impacted environmental resources, restoration plans 'to either eliminate or decrease adverse environmental impacts to the greatest extent possible,' and an environmental management plan post-EER.

The author suspects that Shell has not fully complied with these, in particular the requirement for an Environmental Evaluation post-spill. If so, these reports have not been made available. Many local witnesses said this EE process was not followed for spills. Further, it is a global standard that such post-spill environmental evaluations consist of a comprehensive scientific analysis of the impacted environment, and the author knows of no such assessments for any large spills in the Niger Delta.

5.2.6 Abandonment Plan

5.2.6.1 Requires an operator to present a detailed abandonment plan in its EIA for what 'personnel, equipment, and facilities will be remo-

ved when the project is abandoned temporarily (such as for emergencies) or permanently, how and when they will be removed, the area will be reclaimed, stabilized or otherwise secured.' If such a plan existed for Shell's abandonment of facilities in Ogoniland, then it clearly has not been followed.

5.8.1 Post EIA Monitoring

An operator is required to conduct a comprehensive post-EIA monitoring program to document the actual impacts of a project in relation to the impacts predicted in the EIA. A report is required to be submitted to DPR 'twice a year during the site preparation and construction phases and on an annual basis for a minimum of 5 years after the project/activity/action completion phase.'

VIII. B. Contingency Planning for the Prevention, Control, and Combating of Oil and Hazardous Substance Spills

1.1.1 'License holders...are required by legislation to take/adapt Practical Precautions and/or all steps Practicable to prevent pollution.'

It is abundantly clear that SPDC has not complied with this standard, as there are many additional and reasonable measures that would reduce the incidence rate, size, and impact of spills from their operations in the Delta – increased pipeline maintenance and replacement schedules, additional sabotage prevention technologies, more effective spill detection and response capabilities, etc.

2.0 Content of the Contingency Plan

Shell Nigeria has refused the author's repeated requests for a copy of its Oil Spill Contingency Plan (OSCP) thus making it impossible to judge their specific compliance with these requirements. However, their *actual performance* in responding to some large spills leaves no doubt that they are not in compliance with these EGASPIN requirements.

2.6.1 Requires that 'operators respond for immediately containment of oil spill', and it has been well established that their response to most spills is far from 'immediate', but takes on average several days. There is no place in the world where several days would be construed as 'immediate.'

2.6.2 Requires containment to prevent groundwater contamination as a 'high priority', and this has obviously not been practiced by SPDC.

2.6.3 (i) Requires 'complete containment and mechanical/manual removal' of spills, and there are countless spill sites where SPDC has not satisfied this standard.

2.6.6 'In an event where groundwater gets contaminated, the operator shall take necessary steps to de-pollute the contaminated soil and groundwater.' This has not been met in many spill areas.

2.11 Remediation/Rehabilitation of Affected Area

2.11.1 'It shall be the responsibility of a spiller to restore to as much as possible the original state of any impacted environment.' On the spills reviewed by the author, it is apparent that Shell Nigeria has not met this standard.

2.11.3 Requires that 'for all waters, there shall be no visible sheen after the first 30 days of the occurrence of the spill', and 'for swamp areas, there shall not be any sign of oil stain within the first 60 days of occurrence of the incidence.' Clearly neither of these requirements has been consistently met.

4.0 Mystery Spills

4.1 'An operator shall be responsible for the containment and recovery of any spill discovered within his operating area, whether or not its source is known.' Implicit in this is that an operator is responsible regardless of cause (e.g. sabotage) as well.

5.2 'On an annual basis, an operator's plan shall be reviewed and activated.' It is not clear whether Shell has complied with this requirement.

6.0 Control of Spillages that Impact Underground Waters

6.1 Requires reporting to DPR 'within 24 hours', immediate response, an environmental damage assessment, and 'recovery, treatment, monitoring, and rehabilitation programmes.' SPDC has not fully complied with this for most spills.

7.1 'An operator responsible for a spill shall be required to conduct an Environmental Evaluation (Post Impact) Study of any adversely impacted environment' (as stipulated in VIII-A.2.0). Again, it is unlikely that this requirement has been fully satisfied.

V.III.I Environmental Audits/Reviews

1.0 'Licensees/operators shall conduct environmental audits to facilitate the management control of environmental practices and assessing compliance with the management system and regulatory requirements.'

1.1.1 (ii) 'The objectivity of an audit team, where the audit team should be as practicable as possible, independent of the activities to be audited.' The audits are required to be thorough, objective, and competent.

1.2.3 'The frequencies (as a minimum) of conducting these audits are as follows:

Management Audit – 4 years
Compliance Audit – Quarterly
Site/Facility/Plant Audit – 2 years'

DPR has access to these audits at its discretion, and the operator is required to submit, 'at the end of each year, a list of the environmental audits carried out to the Director, Petroleum Resources.'

It is unclear the extent to which Shell has complied with this environmental audit requirement in Nigerian law.

IX. Schedule of Implementation, Permits Enforcement Powers and Sanctions

4.6.2 Oil/Chemical/Hazardous materials spillages:

(a) 'All avoidable spillages, when they occur, shall attract a royalty not less than =N=500,000, to be deducted at source and additional fine of =N=100,000 for everyday the offence subsists.'

(b) 'The spiller (operator or owner of vessel) shall pay adequate compensation to those affected', and;

(c) 'The spiller shall restore/remediate the polluted environment to an acceptable level as shall be directed by the Director of Petroleum Resources.'

Thus, for spills persisting for years, the government fines could amount to over 100 million Naira. It is unclear what the total amount of fines

and compensation that Shell has paid for spills, but evidence suggests that the amount is far below that required by Nigerian law.

4.7.1 *'any person, body corporate or operator of a vessel or facility, who persistently violates the provisions of these guidelines and standards shall have his lease, license and/or permit revoked.'*

SPDC is clearly a persistent violator of EGASPIN, as well as requirements in Nigerian law that Shell complies with the internationally recognized standards discussed in this report. Thus, the government of Nigeria can and should assert itself as regulator in the public interest.

The government can and should, at a minimum, place Shell Nigeria (SPDC and SNEPCo) on a 2-year administrative probation, require a comprehensive external audit of all Shell Nigeria operations, and require a remedial program to correct significant deficiencies identified in the external audit. The comprehensive remedial audit should have access to all DPR and other federal and state government information on Shell Nigeria facilities and practices, be vested with authority with which to collect testimony and documents from current and former Shell Nigeria employees and government employees (including all past internal audits, the Asset Integrity Management program, the OSCP, the Pipeline Integrity Management System, the JOA and MOU, etc.), and produce a realistic timetable with which Shell must accomplish the remedial actions identified, or their license to operate in Nigeria should be revoked.

4.7 Relevant Corporate and Government Standards

Shell corporate standards

The *Shell Group Environmental Standards* (Shell 2002) state that the company aspires to an internationally recognized 'good oil field practise' standard, as follows:

In Shell, we are committed to having an environmental performance we can be proud of; In all our activities we always take a responsible approach, and our environmental management policy applies globally...We have minimum standards for our major risk areas...and we have assurance processes in place to

confirm that the policy is being followed and that the minimum standards are being met. These include using independent experts to verify our Health, Safety and Environment (HSE) performance data and to certify the environmental management systems of our major installations.

The Shell corporate standard further asserts that all major installations that have significant environmental risks should be 'independently certified by an international certification scheme, such as ISO 14001 or the European Union's Eco-Management and Audit Scheme (EMAS).' Additionally, the standard states:

Any Shell Company, the environmental impact of whose operations is considered material at Group level by the external verifiers of the Group's HSE report, should have its reported Group HSE performance data verified by a competent, independent body.

Further, the *Shell General Business Principles* (Shell, 2002) states:

Shell companies seek a high standard of performance...[and] to conduct business as responsible corporate members of society, to observe the laws of the countries in which they operate...to give proper regard to health, safety, and environment... Therefore, it is the duty of management continuously to assess the priorities and discharge its responsibilities as best it can on the basis of that assessment.

Additionally, these General Business Principles state that Shell will observe the laws of the country in which they operate. This would include then the requirement in Nigerian law that Shell complies fully with internationally recognized standards as found in API and ASME standards.

It is obvious that these professed internal corporate standards for Shell Group are not being met by Shell Nigeria.

Nigerian Government

A further complicating factor in the Niger Delta is that governance is widely acknowledged to be problematic at all levels – local, state, and federal. Poor governance is often cited by Shell as a primary reason for its poor environmental performance in Nigeria. Indeed, since 1995, Trans-

parency International has consistently ranked Nigeria among the 5 worst countries in the world on its Corruption Perception Index. The World Bank's Governance Indicators rank Nigeria in the bottom 6% of the world's population in terms of most governance indicators.

An October 2007 report by Human Rights Watch entitled *Criminal Politics: Violence, "Godfathers" and Corruption in Nigeria* suggests that Nigerian leaders are so corrupt that their conduct 'more resembles criminal activity than democratic governance.' The report summary begins as follows:

Nigeria is mired in a crisis of governance. Eight years since the end of military rule, the country's longest-ever stretch of uninterrupted civilian government, the conduct of many public officials and government institutions is so pervasively marked by violence and corruption as to more resemble criminal activity than democratic governance. This report documents what Human Rights Watch considers to be the most important human rights dimensions of this crisis: first, systemic violence openly fomented by politicians and other political elites that undermines the rights of Nigerians to freely choose their leaders and

enjoy basic security; second, the corruption that both fuels and rewards Nigeria's violent brand of politics at the expense of the general populace; and third, the impunity enjoyed by those responsible for these abuses that both denies justice to its victims and obstructs reform.
(HRW 2007)

Thus, although the Nigerian government does contain strict requirements on petroleum companies discussed in this report, and as detailed in their 2002 *Environmental Guidelines and Standards for the Petroleum Industry* (EGAS-PIN) and other regulations discussed above, these are not being enforced or implemented effectively. It is the author's professional judgment that there is little effective government regulation and oversight of the petroleum sector in Nigeria, and worse, government, as a co-owner, is often complicit in the environmental abuses of the oil sector.

Shell / Nigerian government relationship

As the Nigerian government is a majority partner with Shell Nigeria, ineffective governance is a significant issue in oil field integrity. The Nigerian National Petroleum Corporation (part

BP trying to clean up the Gulf of Mexico





07520044 © Hollandse Hoogte

**Fires burn
around
the BP
Deepwater
Horizon rig
site**

of the federal government of Nigeria) is a 55% owner of SPDC, and exerts important interests in the management of the company. However, Shell is clearly responsible for all operations of SPDC as agreed through the Joint Operating Agreement (JOA) with the three other partners, including budget approval and supervision and funding by the partners (Shell, 2007). A Memorandum of Understanding (MOU) stipulates how the revenues, taxes, and royalties are allocated among the partners.

This structural relationship with the Nigerian government was cited by Basil Omiyi, Country Chair for Shell Nigeria and Managing Director of SPDC in a June 4, 2007 meeting with him in Port Harcourt, as a principal reason for historic poor performance on SPDC's asset integrity, paraphrased as follows:

Operations of the company are funded by the four joint venture partners in proportion to their shareholdings (e.g. NNPC 55%, Shell 30%, Elf 10%, Agip 5%). All budgets - including such critical items as pipeline replacement, safety, and other integrity upgrades - are submitted by the

operator (Shell) to NNPC, from where they are submitted to the President of Nigeria, from where they are submitted to the National Assembly for adjustment and final approval. Shell is precluded by the terms of the JOA from unilaterally funding upgrades in the system, and thus cannot sponsor upgrades without the approval of the Nigeria government. The Nigerian government does not share Shell's commitment to environmental stewardship, and thus has been resistant to most of Shell's budget requests to upgrade the system. This convoluted budgetary process is responsible for delays in system upgrades as the pipeline replacement schedule and gas flare reduction. Shell is optimistic that this barrier can be negotiated away in the future. The partners, including NNPC, remained about \$1 billion in debt to SPDC for basic integrity management this year.

(Basil Omiyi, Country Chair, Shell Nigeria Managing Director, SPDC personal communication, June 4, 2007 Port Harcourt meeting)

In the June 2007 Port Harcourt meeting, Mr. Omiyi admitted that SPDC had not kept up with pipeline maintenance and repair, due largely to the lack of funding approval from the Nigerian federal government and the violent militancy in the region.

In 2006 and 2007 meetings with the Nigeria government's Department of Petroleum Resources (DPR) and the new National Oil Spill Detection and Response Agency (NOSDRA), the author concluded that there is virtually no effective government oversight of the petroleum sector in Nigeria. Shell is well aware of this and, in the author's judgment, has made some effort to correct this situation. However, it is also the author's judgment that Shell has exploited this ineffective governance to its own perceived short-term advantage, and invoked it as an excuse for their poor environmental performance in Nigeria.

Put simply, this is an extremely poor structural arrangement between the host government and the company, as it creates a situation in which it would be difficult to implement integrity upgrades if the majority partner, the Nigeria government in this case, did not share in the environmental stewardship and risk management principles of the company. The author asked for but has not been provided a copy of the JOA, and thus cannot attest to the accuracy of the assertion that the JOA actually prohibits Shell from unilaterally funding system upgrades. If indeed this is the case, then Shell should either renegotiate the JOA and MOU to secure clear budgetary authority for Shell to fund these critical oil field upgrades, or Shell should withdraw entirely from the relationship as it does not facilitate conformity with internationally recognized Best Practice, Nigerian law, Shell's General Business Principles, or Shell-Group's Environmental Standards.

Mr. Omiyi's statement referenced above, in which he blames the cumbersome budget process for the slow pace of upgrading their system, constitutes a clear admission that Shell Nigeria is operating below international best practice standards, and thus that Shell is out of compliance with Nigerian law and/or Shell Group corporate standards. In essence, this is an admission of negligent conduct on behalf of the company.

Shell should submit the results of its Asset Integrity Review, its Pipeline Integrity Management System (PIMS), and its Oil Spill Contingency Plan (OSCP) to independent third-party audits that

would recommend improvements to bring the SPDC performance up to 'good oil field practise' standards discussed in this report.

It no longer seems acceptable for Shell to continue blaming the Nigerian government or the militancy problem for its lack of conformity with 'good oil field practise' in Nigeria. Shell has the financial ability, the technical expertise, and the corporate mandate to achieve a much higher level of performance in the region, and should act accordingly.

4.8 Conclusion: Poor Performance of Shell Nigeria

For several reasons (listed below), the report concludes that Shell Nigeria continues to operate well below internationally recognized standards to prevent and control pipeline oil spills, and thus is out of compliance with Nigerian law:

- lack of implementing 'good oil field practise' with regard to pipeline integrity management (particularly the U.S. IM regulations, API standards, and Alaska's Best Available Technology requirements);
- delay in initiating an Asset Integrity Review and Pipeline Integrity Management System (PIMS) for Shell Nigeria. Shell Nigeria admits it has a backlog in its asset integrity program;
- questionable adequacy of Shell Nigeria's Asset Integrity Review and PIMS, and lack of independent oversight;
- lack of reference to and attention by Shell Nigeria to the Niger Delta as a High Consequence Area for oil spills
- lack of adequate attention by Shell Nigeria to the Niger Delta as an area in which oil facilities are susceptible to Intentional Third Party Damage, requiring enhanced pipeline integrity and monitoring procedures;
- exceptionally high number, extent, and severity of oil pipeline spills in the Niger Delta before, during, and after their Asset Integrity Review and PIMS;
- lack of transparency in Shell Nigeria – the Asset Integrity Review, Pipeline Integrity Management System (PIMS), Joint Operating Agreement, and its Oil Spill Contingency Plan (OSCP) should submit to independent third-party evaluation; and
- lack of adequate oil spill response capability and performance of Shell Nigeria

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Abbreviations

ADEC	Alaska Department of Environmental Conservation
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
BAT	Best Available Technology
CGA	Common Ground Alliance
CPM	Computational pipeline monitoring
DPR	Department of Petroleum Resources (federal government of Nigeria)
EER	Environmental Evaluation Report
EIA	Environmental Impact Assessment
EGASPIN	Environmental Guidelines and Standards for the Petroleum Industry
HCA	High Consequence Areas
IAIA	International Association for Impact Assessment
IM	Integrity Management
IUCN	International Union for the Conservation of Nature
JOA	Joint Operating Agreement
LDS	Leak Detection System
MOU	Memorandum of Understanding
NACE	National Association of Corrosion Engineers
NNPC	Nigeria National Petroleum Corporation
PIMS	Pipeline Integrity Management System
OSCP	Oil Spill Contingency Plan
SCADA	Supervisory Control And Data Acquisition
SPDC	Shell Petroleum Development Company of Nigeria
TPD	Third Party Damage
UNDP	United Nations Development Programme
UNEP	United Nations Environment Programme
US-DOT	U.S. Department of Transportation
US-OPS	US-PHMSA acts through the Office of Pipeline Safety
US-PHMSA	Pipeline and Hazardous Material Safety Administration of the US-DOT

Appendix 1: Shell Nigeria, oil spill figures 1998-2007

Amount of oil spills Shell Nigeria (numbers)

	Total	Sabotage	Controllable	To be classified	% Sabotage
1998	242	68	174		28%
1999	319	160	159		50%
2000	340	137	203		40%
2001	302	147	155		49%
2002	262	160	101		61%
2003	221	141	80		64%
2004	236	157	79		67%
2005	224	138	86		62%
2006	241	165	50	26	68%
2007	330	221	109		67%
2008	155	115	40		
2009	132	95	38		
Average 1998-2009	250	142	106	3	57%
Average 1998-2002	293	134	158	0	46%
Average 2003-2009	220	147	69	5	67%

Source: Shell Nigeria, annual reports 1999-2006; 2007, 2010: briefing note 'Oil spills'

Volume oil spills Shell Nigeria (in barrels)

	Total	Sabotage	Controllable	To be classified	% Sabotage
1998	50.200	19.000	31.200		38%
1999	23.377	16.364*	7.013		70%
2000	30.751	17.644	13.107		57%
2001	76.854	38.711	38.143		50%
2002	20.007	18.724	1.278		94%
2003	9.900	6.732	3.168		68%
2004	8.317	8.064	253		97%
2005	11.921	11.265	659		94%
2006	23.000	12.600	10.400		55%
2007	30.000	18.500	11.500		62%
2008	102000	46000	56000		45%
2009	105300	103	2300		98%
Average 1998-2009	40.969	17.809	14.585		59,00%
Average 1998-2002	40.238	22.089	18.148		55%
Average 2003-2009	41.491	14.752	12.040		67,00%
Total 1998-2009 (barrels)	491627				
Total 1998-2009 (liters)	78168693				

Source: Shell Nigeria, annual reports 1999-2006; 2007, 2010: briefing notes 'Oil spills'

* = 1999: excluded sabotage spill Ekakpamre

Volume oil spills Shell Nigeria compared to volume total Shell-group

	Total	Sabotage	Operational	Hurricanes
Average 1998-2009	50,00%	100%	28,00%	0%
Average 1998-2002	41%	100%	24%	0%
Average 2003-2009	61,00%	100%	35,00%	0%

Volume oil spills Shell Nigeria (in 1.000 tons)

	Total	Sabotage	Controllable
1998	6,8	2,6	4,2
1999	3,2	2,2	1,0
2000	4,2	2,4	1,8
2001	10,5	5,3	5,2
2002	2,7	2,5	0,2
2003	1,3	0,9	0,4
2004	1,1	1,1	0,0
2005	1,6	1,5	0,1
2006	3,1	1,7	1,4
2007	4,1	2,5	1,6
2008	13,8	6,3	7,6
2009	14,3	14	0,3

Source: Shell Nigeria, annual reports 1999-2006; 2007, 2010: briefing note 'Oil spills', one metric ton corresponds to 7,35 barrels of oil.

Volume oil spills Shell-group (in 1.000 tons)

	Total	Sabotage	Operational	Hurricanes
1998	13,2	2,6	10,6	
1999	18,7	2,3	16,4	
2000	9,9	2,4	7,5	
2001	17,8	5,2	12,6	
2002	7,4	2,5	4,9	
2003	6,7	0,9	5,8	
2004	6,1	1,1	4,0	1,0
2005	9,0	1,5	3,6	3,9
2006	6,3	1,7	4,6	
2007	6,7	2,5	4,2	
2008	15,3	6,5	8,8	
2009	14,2	13,9	1,3	

Sources: Royal Dutch Shell, annual and sustainability reports 2006, 2007 and 2009. Figures on sabotage en operational causes over 2006 en 2007 are not totally clear reported.

Appendix 2:

Oil spill figures from Nigerian government

	Year	Number of spills	Volume (in bbls)
1	1976	128	26.157
2	1977	104	32.879
3	1978	154	489.295
4	1979	157	694.117
5	1980	241	600.511
6	1981	238	42.723
7	1982	257	42.841
8	1983	173	48.351
9	1984	151	40.209
10	1985	187	11.877
11	1986	155	12.905
12	1987	129	31.866
13	1988	208	9.172
14	1989	195	7.628
15	1990	160	14.941
16	1991	201	106.828
17	1992	367	51.132
18	1993	428	9.752
19	1994	515	30.283
20	1995	417	63.677
21	1996	430	46.353
22	1997	339	59.272
23	1998	390	98.345
Total		5.724	2.571.114

The following table (cited in Nwilo and Badejo, 2001) presents spill data recorded by the Nigerian Department of Petroleum Resources (DPR) for years 1976-1998 (in the Niger Delta). Between 1976 and 1998 a total of 5.724 incidents resulted in the spill of approximately 2.571.114 barrels of oil into the environment.

These spill volume estimates are very close, but not identical, to those reported from the Niger Delta Environmental Survey, citing Nigerian National Petroleum Corporation (NNPC) 1997 Annual Statistical Bulletin, as cited in Orubu, 2004, which reported a total spill volume of 2.382.373 barrels for the period 1976 - 1996. In its Niger Delta human development report of 2006 the United Nations Development Programme states: 'Available records show that a total of 6,817 oil spills occurred between 1976 and 2001, with a loss of approximately three million barrels of oil.' (UNDP 2006). This would be on average 262 oil spills each year, together spilling more than 115.000 barrels of oil.

Appendix 3: Pipeline repair requirements in U.S. Integrity Management law

The following conditions require *immediate repair*:

1. metal loss greater than 80% of wall thickness regardless of dimensions.
2. a calculation of the remaining strength of the pipe shows a predicted burst pressure less than the established maximum operating pressure (MOP) at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines"(1991) or AGA Pipeline Research Committee Project PR- 3- 805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)).
3. a dent located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of metal loss, cracking or a stress riser.
4. a dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter.
5. an anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

The following anomalies must be repaired *within 60 days of discovery*:

1. a dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 3% of the pipeline diameter (greater than 0.250 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).
2. a dent located on the bottom of the pipeline that has any indication of metal loss, cracking or a stress riser.

And the following must be repaired *within 180 days of discovery*:

1. a dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld.
2. a dent located on the top of the pipeline (above 4 and 8 o'clock position) with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12).
3. a dent located on the bottom of the pipeline with a depth greater than 6% of the pipeline's diameter.
4. a calculation of the remaining strength of the pipe shows an operating pressure that is less than the current established maximum operating pressure at the location of the anomaly.
5. an area of general corrosion with a predicted metal loss greater than 50% of nominal wall.
6. 6 predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.
7. a potential crack indication that when excavated is determined to be a crack.
8. corrosion of or along a longitudinal seam weld.
9. a gouge or groove greater than 12.5% of nominal wall.



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