Public Protection and Gas Monitoring; Its Impact on the Community, Environment and the Bottom Line
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Abstract

During typical well operations, production activities or processing plants, especially in sour environments, a barrier between the site and populated areas such as towns and villages is often overlooked. Operators and contractors are focusing on protecting site personnel while relying on simple general public guidelines to alert the neighboring communities. While the industry is seeing great progress towards a digital oilfield concept where monitoring of production and optimization of flow rates and fluids are remotely actuated to reduce the burden of manning the various oilfields and maximizing production of the reservoir, these concepts did not filter to the safety management of sites and to the public protection procedures that would apply on these sites.

A recent technology failure on March 6th 2011 at the Karachaganak Field resulted in a fatal outcome\(^1\). This incident occurred in March 2011, where one employee died and a second employee was found in a nearby hanger in a critical condition. Both employees were conducting cleaning works at the time of the incident. Individual protection gear, a gas indicator and special safety instructions all failed to save the life of the contractor's employee from Karachaganak's fatal atmosphere during the technology failure.

Village resident and leader of the village campaign for relocation, stated: "In accordance with official documents, in the event of an emergency at a well site, a plume of hydrogen sulfide could reach the village within 10-30 minutes, depending on the direction of the wind. The contractor is only obliged to notify village residents via a signal from a special tower located in the village and it is local authorities who must ensure the evacuation of residents. How this is to be conducted in such a short period of time remains unclear. Moreover, Berezovka residents themselves do not know what to do in such a situation; and what if an emission occurs at night? It is disturbing to think of the consequences that may occur in the event of an H2S situation".

Another technical failure in Canada in 2009 caused the release of 30,000 cubic meters of gas containing 6200ppm of H2S. The nearby community was not alerted until six hours after the release causing massive concern over procedures for public protection\(^2\).

This paper discusses lessons learned from the digital oilfield concepts and its applicability to remote safety monitoring and safety processes. In addition, suggestions for improvements and coordination with local villages and their authorities are also discussed.

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1. **Background**

The vision for the Digital Oilfield (Figure 1) is one “where operators, partners, and service companies seek to take advantage of improved data and knowledge management, enhanced analytical tools, real-time systems, and more efficient business processes” CERA: ’Digital Oilfield of the Future’.

A Digital Oilfield is about remotely visualizing, monitoring and operating wells and allowing operators to make more timely and qualified production decisions, while reducing operational risks on personnel such as trips and toxic gases exposures. A digital oilfield operation can be safer, simpler and easier to manage.

A Digital Oilfield operation provides three key aspects of managing an oil and gas asset according to CERA:

1. Total asset awareness where data is acquired, interpreted, shared and visualized collaboratively using new classes of downhole gauges, surface sensors, data and information management and visualization and modeling mediums.
2. Acting on this awareness where operators are capable of taking decisions in order to capture more hydrocarbons or operate more efficiently using new tools such as intelligent completions, real time drilling and remote actuation.
3. Total asset optimization where integrating surface and subsurface data and systems using analytical tools in order to remove potential bottlenecks and forecast future behaviors in order to right-size facilities and pipelines and optimize the reservoirs.


Fig 1: Digital Oilfield


2. **H2S and its impact**

H2S or Hydrogen Sulphide is an IDLH (Immediate Danger to Life and Health), poisonous gas and its exposure to humans leaves serious effects that could range from death to lasting physiological and neurological sicknesses.

- H2S gas is also odorless, colorless and heavier than air which makes detection by humans very difficult. H2S occurs naturally in most hydrocarbon bearing formations and could also be generated through well interventions like fracking and flooding.

Oil and Gas companies typically plan for any potential H2S presence and leaks to protect their site employees and contractors. They use gas monitoring devices, supply breathing air to required personnel and provide emergency plans to evacuate or rescue personnel who are potentially exposed.
One area of concern, that is often being neglected, is the protection of the community where drilling operations occur in highly populated areas in the event of a gas release.

As H2S gas leaks in the air, solar heating/radiative cooling determined by cloud coverage and latitude from the equator, wind speed and direction, surface roughness, terrain and height from the ground are all factors that will affect where the plume will be headed and whether it will reach a populated area with a concentration that is harmful to the community.

In addition to the above factors, source elements like diameter, initial jet density, velocity, proximity, obstacles and fallouts are important when estimating or predicting the dispersion of this toxic gas and its impact on a nearby community. The effect of H2S on people varies with the concentration level. Table 1 details the various health effects:

<table>
<thead>
<tr>
<th>Concentration (ppm)</th>
<th>Length of exposure</th>
<th>Effect</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.0057</td>
<td>Community/chronic</td>
<td>Eye and nasal symptoms, coughs, headaches and/or mucous membranes</td>
<td>Parth-Pelinson, p. 316.</td>
</tr>
<tr>
<td>0.03 – 0.02</td>
<td>Immediate</td>
<td>Detectable odor</td>
<td>EPA Report 1993, p.III-5</td>
</tr>
<tr>
<td>0.1</td>
<td>Community/chronic</td>
<td>Neurophysiological abnormalities</td>
<td>Logator, p. 124</td>
</tr>
<tr>
<td>0.2</td>
<td>n.r.</td>
<td>Detectable odor</td>
<td>Fuller, p. 40</td>
</tr>
<tr>
<td>0.210 – 0.300</td>
<td>Prolonged</td>
<td>Nuisance due to odor from prolonged exposure</td>
<td>Milby, p. 194</td>
</tr>
<tr>
<td>2 – 8</td>
<td>Community</td>
<td>Malaise, irritability, headache, insomnia, nausea, throat irritation, shortness of breath, eye irritation, diarrhoea, and weight loss</td>
<td>EPA Report 1993, p. III-32</td>
</tr>
<tr>
<td>10</td>
<td>10 minutes</td>
<td>Eye irritation, chemical changes in blood and muscle tissue after 10 minutes</td>
<td>New York State Department of Health</td>
</tr>
<tr>
<td>&gt; 30</td>
<td>Prolonged</td>
<td>Fatigue, paralysis of effaction from prolonged exposure</td>
<td>Snyder, p. 200</td>
</tr>
<tr>
<td>50</td>
<td>n.r.</td>
<td>Eye and respiratory irritation</td>
<td>Fuller, p. 40</td>
</tr>
<tr>
<td>50 – 100</td>
<td>Prolonged</td>
<td>Prolonged exposure leads to eye irritation; eye irritation (painful conjunctivitis, sensitivity to light, tearing, clouding of vision) and sensor eye injury (permanent scarring of the cornea)</td>
<td>Milby, p. 194; EPA Report 1993, p. III-5</td>
</tr>
<tr>
<td>200</td>
<td>n.r.</td>
<td>Respiratory and other mucous membrane irritation</td>
<td>Snyder, p. 200</td>
</tr>
<tr>
<td>250</td>
<td>n.r.</td>
<td>Damage to organs and nervous system; depression of cellular metabolism</td>
<td>EPA Report 1993, p. III-5</td>
</tr>
<tr>
<td>320 – 530</td>
<td>Prolonged</td>
<td>Possible pulmonary edema from prolonged exposure</td>
<td>Milby, p. 193</td>
</tr>
<tr>
<td>500</td>
<td>30 minutes</td>
<td>Pulmonary edema with risk of death</td>
<td>Kilburn (1999), p. 212</td>
</tr>
<tr>
<td>560 – 1000</td>
<td>Immediate</td>
<td>Systemic symptoms after 30 minutes</td>
<td>Fuller, p. 40</td>
</tr>
<tr>
<td>750</td>
<td>Immediate</td>
<td>Unconsciousness, death</td>
<td>Fuller, p. 40</td>
</tr>
<tr>
<td>730 – 1000</td>
<td>Immediate</td>
<td>Abrupt physical collapse, with possibility of recovery if exposure is terminated; if not terminated, fatal respiratory paralysis</td>
<td>Milby, p. 192</td>
</tr>
<tr>
<td>1000 – 2000</td>
<td>Immediate</td>
<td>Immediate collapse with paralysis of respiration</td>
<td>Kilburn (1999), p. 212</td>
</tr>
<tr>
<td>3000</td>
<td>Immediate</td>
<td>Death</td>
<td>Fuller, p. 40</td>
</tr>
</tbody>
</table>

Table 1: Health Effects Associated with Hydrogen Sulfide

3. Digital Oilfield and H2S

The vision of a Digital Oilfield relies on its key capabilities of having full asset awareness, giving users more detailed and current information and automated monitoring of all the components of an oil and gas asset from the pores of the well bore to the sales point. In addition, another key capability includes the ability to model and visualize the behavior of the asset and to be able to work seamlessly and in collaborative manner, and finally the capability of providing a more reliable and capable remote actuation system in order to provide agility and flexibility in managing any eventuality whether it is controlling downhole flow, enhancing the downhole processing or further extending the remote actuation distance.

Companies typically start to plan their vision for the Digital Oilfield and how they think the future of their asset would look like in five or ten years. They discuss and agree on the reasons why they will need to go through this massive expense and implement a digital oilfield weighing all risks and rewards.

It is not an easy task as new and innovative technologies aiming at enhancing E&P operations are available and ready to be deployed. Companies now have a large choice of options which need to be examined when looking at establishing the vision and strategy of the Digital Oilfield.

However, key focus drivers would become apparent in the first phase of planning. Drivers could be the need to make real time decisions or the need to enhance and optimize the productivity of the asset or the resolution or mitigation of the safety of the operation and environmental compliance. Assets with H2S content might demand a different level of attention as companies craft their key drivers; objectives, operational safety and environmental compliance become guiding drivers that will dictate the productivity aspect of the field and the implementation thereof.

H2S presence in the asset requires modification to the processes in sensing, detecting and reacting to H2S presence. Uncontrolled H2S causes concern for:

- Safety of personnel while drilling, well testing, surveillance and production operations.
- Safety of the community and surrounding areas.
- Nuisance odors and emission regulations in the environment that might need to be addressed.

Summarized below are two examples of failed technology in H2S fields that created accidents affecting the safety of personnel on site and the safety of the surrounding community.

3.1. Oil and Gas Operator in Canada: 2009 accident

Digital Oilfield setup and emergency operation might not be enough. The case of an oil and gas operator in Canada in 2009 revealed that the emergency shutdown (ESD) valve at the well closed automatically, but was unable to stop the flow of gas (from the failed tee) because the ESD was downstream of the failure point. In this instance, human operators had to be dispatched and work under SCBA to isolate the problem and control the gas flow. Further complications, included failure of the breathing apparatus, forcing the site operators to evacuate. However, residents failed to be alerted, although some local residents took the initiative to evacuate.

Leak detection and emergency isolation at the site did not achieve a timely detection of the leak or control of the escaping gas. SCADA information indicates a significant gas release occurred with the sudden failure of the tee. Gas flowed uncontrolled from the well head for approximately 27 minutes before the first alarm was detected.
A review of the emergency planning zone to identify residents who may require contact was done only after visually confirming the leak, and resident notifications did not begin until 71 minutes after the first alarm was activated (see below Figure 2). Approximately 30,000 cubic metres of natural gas containing approximately 6200 ppm H2S was released to atmosphere during the incident. As previously mentioned, the ESD at the wellsite failed to control the flow of gas at the failure point as it was situated downstream of the failed tee.


**Figure 2: Incident time log**


The Failure Investigation Report conducted by the BC Oil and Gas Commission in 2010 highlights:

- Communication to the public did not achieve the desired results regarding notification.
- Response to this incident did not entirely conform to the established Emergency Response Plan.
- No review of the emergency planning zone to identify residents who may require contact until after visually confirming the leak.
- Leak detection and emergency isolation at the site did not achieve timely detection of the leak or control of the escaping gas.

### 3.2. Karachaganak field: 2011 accident

A technology failure at the Karachaganak Field resulted in a fatal outcome


On the night of March 6, 2011, one field worker died of H2S poisoning and a second worker was taken to the hospital in grave condition as a result of an accident in the processing complex during the cleaning of a tank, due to a broken fastener resulting in an outflow of accumulated H2S. Individual protection gear, a gas indicator and special safety instructions all failed to save the operator’s employee from Karachaganak’s fatal atmosphere during the technology failure.

In light of this tragedy, there is increased concern by the residents of the village of Berezovka which sits on the border of the Karachaganak Field’s five-kilometer ‘Sanitary Protection Zone’. In the event of a serious accident at the field and the emission of H2S, village residents would have little chance of escaping tragedy.

As Svetlana Anosova, village resident and leader of the village campaign for relocation, stated: “In accordance with official documents, in the event of an emergency at a well, a plume of H2S could reach the village within 10-30 minutes, depending on the direction of the wind. The operator is only obliged to notify village residents via a signal from a special tower installed in the village and it is lauthorities who must ensure the evacuation of residents. How
this is to be done in such a short period of time is unclear. Moreover, Berezovka residents themselves do not know what to do in such a situation. And what if an emission occurs at night? It is terrible to think of the consequences.'

Since 2002, Berezovka residents have been campaigning for the village to be relocated from the Sanitary Protection Zone, as operations at the Karachaganak Field threaten their health, and the field’s proximity to the village violates the national law of Kazakhstan.

One can attribute these accidents to a process failure or a human error or faulty equipment or a combination of all three. But whatever the reasons could have been, we are putting human life in danger both on the site and in the village or town in proximity of that site, and there is no excuse. The Oil and Gas industry has come a long way drilling horizontal wells and mastering sophisticated technologies, yet faltering over simple processes and fundamentals.


Gas monitoring is one of the key processes of a Digital Oilfield.

4.1. Surface Monitoring and equipment:

- Today the surface H2S protection is limited to gas monitors linked to audible alarms. In the case of Digital Oilfields, the surface monitoring can be greatly improved by integrating gas detection into the Digital Oilfield processes.
- Today, only ambient H2S detection is required and must consist of a continuous H2S detection that activates audible and visual alarms.
- In order to be more efficient, surface gas monitoring sensors should also record data such as pressure, volume, temperature, wind direction and speed. This data would be communicated to the control room and, using additional software that would analyse and model the information, would create a dispersion model and initiate alerts and alarms.
- These alerts would then be actioned by the responsible asset team member who would initiate the emergency response plan.
- The surface equipment should be able to be remotely actuated to respond to the emergency plan and control the wells for safety.

4.2. Perimeter Monitoring and Alarming:

- Similar to the surface gas monitors, perimeter monitoring equipment would need to be deployed and integrated in the Digital Oilfield gas monitoring and actuation workflow. These monitors should be deployed around the premises in key locations to provide the public with the assurance of protection using several layers of controls and with foolproof systems.
- Some innovative monitoring units like ProtectUs® by United Safety are available today. These units incorporate a self-sustained gas detection unit powered by solar panels and instrumented with the same communication system set up as the surface equipment.
- Ideally, these units should also measure wind speed and direction, pressure and temperature and they should also allow integration of the topography in the data using GPS enabled maps.
- Dispersion modeling could be run internally in these units allowing more detailed mapping of the plume dispersion and the area likely to be affected, thereby creating an early alert and warning signs to the nearby workers or residents. This alert would be strengthened by the control room implementation of the emergency response plan.
Figure 3: Example of surface monitoring setup including perimeter protection  
Ref: United Safety Technical Brochure

Figure 4: Application example in RF mode  
Ref: United Safety Technical Brochure
4.3. Downhole instrumentation and equipment:

This consists of a permanent downhole gauge and a sub-surface safety valve. The objective is to provide safety to the wells and data measurements downhole. Unfortunately, today there are no H2S detection gauges that could be deployed to give early warning signals downhole. However, Ph monitoring installed as close as possible to the flowline discharge should sound an alarm in case of a drop in Ph. In addition, Sulphide content must be monitored either continuously or via hourly HACH tests. The downhole monitoring of H2S notwithstanding, there are numerous ways to monitor downhole leaks, just to name a few:

- Pipeline Monitoring: Use of flowline and surface pressure measurements for honoring pipeline integrity limit the calculation of the pressure drop across the system for early integrity problem detection.
- Completion integrity monitoring: Use of annulus pressure measurements for early detection of completion integrity problems (faulty seal on packers, leak in tubing/casing, cement integrity)
- Well surveillance: Downhole and surface pressures and temperatures are monitored. In case of a violation of limits, an alert/alarm is triggered. The well status is monitored by tracking choke size, SSV, SSSV and delta pressure across the choke.

4.4. Communication:

Data acquired as a result of the surface and downhole monitoring must be sent to the asset team in a secure manner, either in real time or on demand. Data would need to be analyzed and actions transmitted back to the equipment to actuate them as part of the emergency response plan. Typically the communication system would be using either GPRS or WiMAX protocols that could be switchable to allow for redundancy.

4.5. Data Gathering and Analysis:

As H2S gas leaks in the air, solar heating/radiative cooling determined by cloud coverage and latitude from the equator, wind speed and direction, surface roughness, terrain, height from the ground are all factors that will affect where the plume will be headed and whether it will reach a populated area with a concentration that is still be harmful to the community.

In addition to the above factors, source elements like diameter, initial jet density, velocity, proximity, obstacles and fallouts are important to building the dispersion model and predicting the impact on a nearby community.

Data gathered by the various instruments downhole, on the surface and in the perimeter is transmitted to the control room and analysed using dispersion modeling software. The result of the study would determine an EPZ (Emergency Planning Zone) in order to then move to stage two which is an implementation of monitoring, alarming and evacuation plans within the EPZ.

4.6. Emergency Response Plan:

The combination of the H2S monitoring and action workflow creates an emergency response plan that provides the preparedness and response to the detection or release of H2S. The objective is to provide a plan that is quick, effective and appropriate in order to protect the public, the company and its personnel from fatalities or irreversible health effects and safeguard the environment.

It should determine representation, activities and plans covering employees and contractors, local authorities and government.

It should also assist personnel in determining the level of emergency and the extent of the actions and response needed. The content of an emergency response plan as defined by the BC Oil and Gas Commission should include:

- Emergency Definition and Action
- Responsibilities of Company Personnel
- Government Roles and Responsibilities
- Evacuation and Sheltering Plans
- Ignition Procedures
- Additional Public Protection Measures
- Post Emergency Procedures
- Emergency Equipment List
- Emergency Contact Lists
- Residents Information
- Maps – Emergency Response Plan
- Forms

An important step in the preparation of the ERP is to determine the various EPZs as they relate to the nature of the field.

As mentioned above, an EPZ is a priority area that surrounds the exploration or production work, whether it is around a well, pipeline or facility and where an immediate response is required in the event of an emergency.

Below (Figure 5) is a flowchart taken from the Oil and Gas Commission of British Columbia:

![ERP planning flowchart](image)

**Figure 5 – ERP planning flowchart**

*Source: Oil and Gas Commission of British Columbia*

The minimum requirement for an ERP is to have a corporate plan. It is normally accepted as long as there is permanent residence, public facilities or places of business within the emergency planning zone. However, in all other instances, specific plans should be drawn depending on the type of planning and the type of risk involved, specifically as it relates to a sour well EPZ, a sour production facility EPZ, a sour pipeline or multiphase EPZ.
Sour well EPZs:

The EPZs for sour well is defined using Gaussian dispersion equation for steady state releases (Figure 6):

\[
\begin{align*}
\text{EPZ} &= 2.0xQ_{\text{H}_2\text{S}}^{\frac{3}{5}} \ (\text{km}) \ Q_{\text{H}_2\text{S}} < 0.3 \text{ m}^3/\text{s} \\
\text{EPZ} &= 2.3xQ_{\text{H}_2\text{S}}^{\frac{3}{5}} \ (\text{km}) \ 0.3 \text{ m}^3/\text{s} \leq Q_{\text{H}_2\text{S}} < 8.6 \text{ m}^3/\text{s} \\
\text{EPZ} &= 1.9xQ_{\text{H}_2\text{S}}^{\frac{3}{5}} \ (\text{km}) \ Q_{\text{H}_2\text{S}} \geq 8.6 \text{ m}^3/\text{s}
\end{align*}
\]

Figure 6: Sour Well EPZ  
Source: Oil and Gas Commission of British Columbia

Sour Production Facility EPZs:

For a sour production facility, the EPZ is calculated using the largest H2S volume release from any pipeline entering or leaving the facility.

\[
V = (2.232 \times 10^{-6} \ D^2 \ L \ (P+101.325) \ H) / Z \ (T+273)
\]

Where:  
\(V\) = maximum potential H2S release volume in m3  
\(D\) = internal diameter of pipe in millimetres (mm)  
\(L\) = length of pipeline between block valves (km)  
\(P\) = licensed maximum operating pressure in kilopascals (kPa)  
\(H\) = licensed H2S content (moles/kilomole) for the pipeline  
\(Z\) = compressibility factor at Pr and Tr  
\(T\) = pipeline minimum operating temperature (oC)
Sour Pipeline and Sour Multiphase Pipeline EPZs:

The EPZ for a sour pipeline is determined similarly to the above but conducted for each segment of the pipeline. Figure 7 shows the chart for EPZ for plants, pipeline and facilities.

![Figure 7: Sour Pipeline and Facilities EPZ](image)

Source: Oil and Gas Commission of British Columbia

5. Conclusion:

In the wake of several accidents involving H2S (sour gas) release, while the industry has achieved tremendous progress in technologies, processes and analysis around the digital oilfield, gas monitoring and public protection is lagging behind and integration of the key processes of a digital oilfield is essential to achieving full protection of the public.

The need to develop a full workflow covering the integration with downhole instrumentation, surface monitoring and equipment, communication to control rooms, analysis of data and dispersion modeling and culminated with a solid ERP plan, while understanding the various EPZs and involving company, government, local authorities and residents, is key to sustaining long term protection of the public when they are near sour fields and where H2S gas remains a real threat to communities.

End