Havtil
CO2 Blowout Considerations

Confidential Report

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Technical Note

Contents

Introduction

Havtil has requested that Wild Well Control, Inc. (WWCI) provide an overview of the well control response and intervention considerations for blowout events associated with Carbon Dioxide (CO_2) releases. WWCI is an industry leader in emergency well control response with extensive experience in responding to blowouts, including CO_2-related well control events.

This technical note includes:

- Practical considerations that may arise while regaining control of a CO_2 blowout.
- Various scenarios that could be encountered while intervening on a high-concentration CO_2 blowout and considerations for reaching the objective of regaining control of the well safely.
- A summary of well control modeling tools with respect to CO_2 scenarios. Modeling tools are an essential part of response, and pre-planning well control activities. The modeling of CO_2 as it transitions between different phases can be challenging.

Blowout considerations for CO_2 releases - CO_2 Behavior

There are four states of CO_2, all of which could be present in a wellbore during a well control event; gas, liquid, solid, or supercritical. At surface conditions and temperatures, CO_2 is a gas. If pressurized sufficiently, it becomes liquid. Low temperatures result in the transition to the solid, dry ice phase – refer to the phase diagram in Figure 1.

CO_2 has a critical point of approximately 74 bar at a temperature of 31°C. These pressure and temperature points are well within the typical operating window found in an oil and gas well, and as such, the CO_2 phase change is almost guaranteed to occur somewhere in the wellbore if pressure control is not maintained or if containment is lost, leading to a blowout scenario.

Most CO_2 injection projects use storage reservoirs with a cap rock or top seal at a minimum depth of 800m. This is by design, as at this depth, the CO_2 can be expected to remain in a dense phase in the reservoir. CO_2, in its dense or supercritical phase, has a gas-like viscosity. However, the CO_2 density at this same reservoir pressure and temperature in the supercritical phase is more like the density of a liquid. This behavior is useful in terms of storage, as the dense condition allows a higher amount of mass per unit of volume to be stored in the reservoir. CO_2 has a significantly lower critical temperature and pressure as compared to natural gas and hence can transition to a liquid phase at much lower pressures and temperatures as compared to a typical natural gas. When depressurization occurs, there is an opportunity for a rapid reduction in density and expansion of CO_2 due to the large amount of stored energy.

In a blowout scenario, the exit point of the release can be at surface or subsea, depending on the design of the well and the specifics of the leak path scenario. Subsea and atmospheric scenarios have different blowout exit point pressures, which in turn can affect the behavior of the CO_2. In deepwater subsea conditions, the hydrostatic column can exert a pressure greater than ≈100 bar, which means CO_2 can exist in solid, liquid, or supercritical forms. If there is a form of containment in the scenario, the phase change could also occur in the circulation system wherever the transitional pressure and temperature conditions are met; this could be in a riser or chokeline during a subsea well control circulation, for example.

Should the exit point be on land or at surface, then the blowout flow will ultimately be exposed to atmospheric pressure and temperature at the exit point, where CO_2 can only exist as a gas. However, prior to release, Joule Thompson cooling as the CO_2 expands can result in very low temperatures. When coupled with higher than atmospheric pressures in the well, solid CO_2 (dry ice) can be formed. Solid pieces of CO_2 may be expelled from the wellbore at the release point.

The varied pressure profile in a well, coupled with the transient and highly dynamic nature of a blowout scenario, make the phase change behaviors very scenario-specific to the depths, temperatures, fluid compositions, and release point conditions. When responding to a CO_2 blowout, the downhole pressure profile, and in turn, the selection of the correct well control strategy can be less clear-cut than the well established practices for oil and natural gas blowouts. The conditions could also change as the kill strategy is implemented. The phase change is also difficult to model with well control modeling tools, at least in cases where rapid transition occurs or cases where supercritical, liquid, gas, and solids are all present at some point in the blowout flow path.

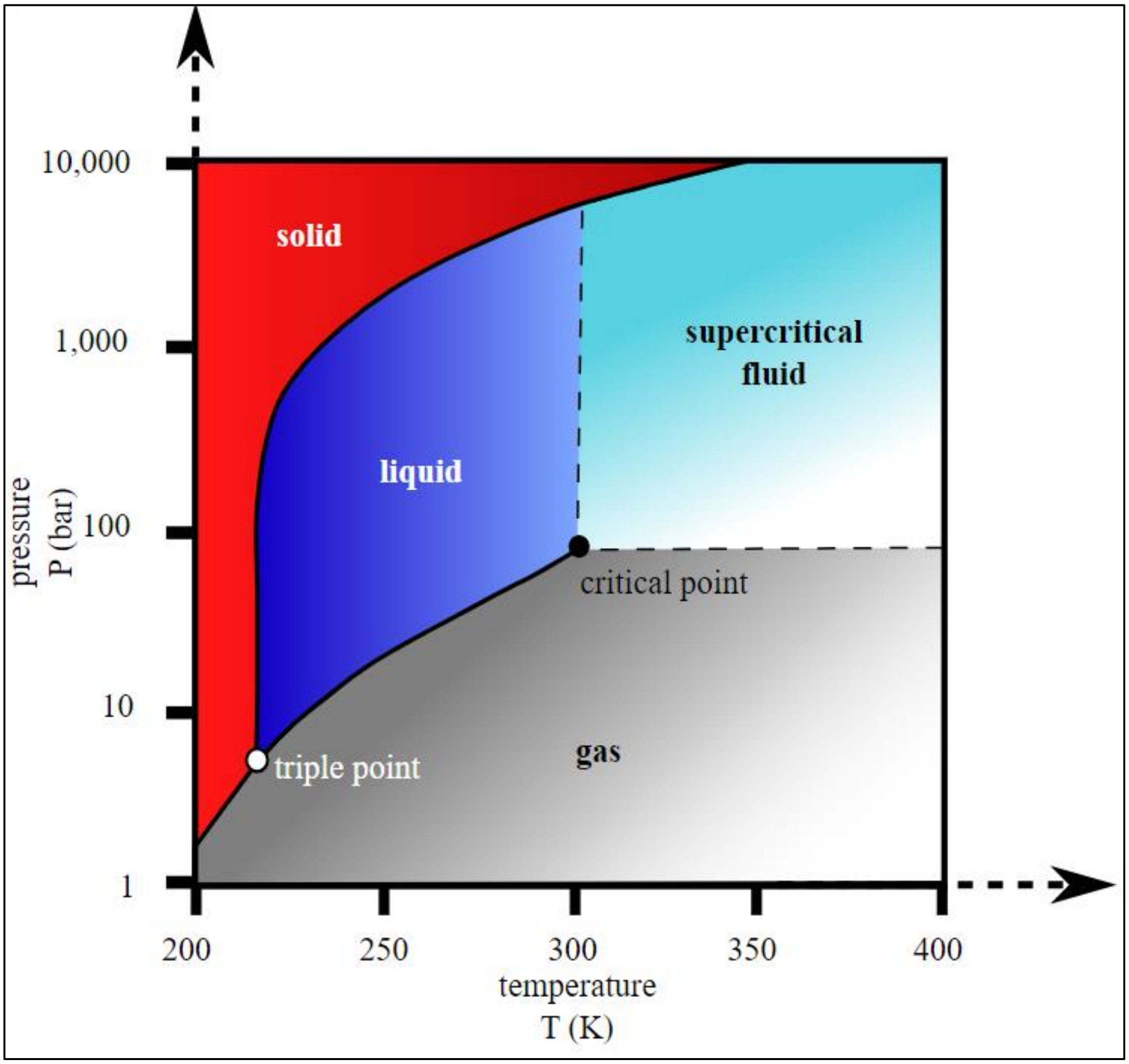


Figure 1 - CO_2 Phase Diagram

[Courtesy of Bambido, Thyagarajan, Dhi, Prasad, and Banerjee – Comparison of Convective Heat Transfer Characteristics of Supercritical Fluid for Circular-Pipes in Horizontal Flow, Supercritical CO_2 Power Cycles Symposium 2022, Paper 125]

CO_2 injection wells are different from a hydrocarbon well in that they see the highest pressures at the end of the well life cycle rather than the beginning. Abandonment and long-term integrity are therefore critical for CO_2 wells, which will see sustained pressure for much longer periods, perhaps for eternity, as opposed to oil and gas wells, which are depleted when produced.

HSE risks to personnel and equipment from the CO_2 plume

Typically, the highest consequence risks when WWCI responds to blowouts are related to the release of flammable and/or toxic hydrocarbons. CO_2 is not flammable and is not toxic when in low levels of concentration. This does not mean that there is no risk when responding to a CO_2 blowout. There are still significant risks, albeit different hazards present to response teams.

CO_2 is heavier than air (1.55 sg), meaning that when it is released into the atmosphere, it will gather and accumulate in low areas. The higher density means it can displace oxygen in the low-lying areas, creating a significant danger of oxygen deficiency for response teams. Oxygen deficiency and exposure to CO_2 can cause headaches, nausea, disorientation, confusion, dizziness or even unconsciousness and ultimately death via asphyxiation. Exposure to CO_2 is limited to below 5,000 ppm based on an 8-hour TWA; exposure to 40,000 ppm (4%) is immediately dangerous to life and health.

Constant gas monitoring is required by any response team working in and around the area of a CO_2 blowout. CO_2 is colorless and odorless, so calibrated gas monitoring is the only reliable method of establishing the concentration levels. Self Contained Breathing Apparatus (SCBA) may be required by the response team to maintain a safe, breathable atmosphere, particularly for any enclosed spaces or low-lying accumulation areas – enclosed well bays and cellars would be examples of likely accumulation areas at a rig site. When CO_2 is present above 5,000 ppm, respiratory protection planning must include the use of a supplied air or SCBA with a full facepiece operated in pressure-demand or positive-pressure mode. It is important to avoid using Oxygen Content as a safe reference since asphyxiation by CO_2 concentrations can occur with 21% oxygen present. It is important to note that a blowout situation is highly dynamic, and concentrations of CO_2 in the work area can vary greatly depending on the blowout's cycling behavior and atmospheric conditions. It is for this reason that any onsite monitoring procedure will be developed and implemented based on daily work operations and updated on a regular basis to reflect any change in conditions.

Oxygen deficiency also presents a significant issue for response teams in that it prevents combustion engines from working. This means that generators, engine-driven equipment such as cranes, and heavy machinery may cut out or fail to start. Pump units used to pump kill fluid into the well may not be able to function if the intakes are placed in areas with high levels of CO_2. This issue also extends to access and egress options at the blowout location. Vessels or rescue craft engines may be starved of oxygen, and helicopter engines could be affected if they fly at low levels. Reboarding of any offshore platform in any significant CO_2 blowout scenario is likely to be extremely challenging, in particular if the helideck is within the CO_2 release envelope. Access by boat is more likely to see the plume due to the low-lying, heavier-than-air behavior of CO_2.

When released into the atmosphere, the cold CO_2 can react with moisture present in the air to create large, dense clouds. These clouds can present a barrier to operational response, as the team will have no or limited ability to visually inspect the wellhead and release point if the cloud is of sufficient size. The size of the cloud may also inhibit the safe maneuvering of heavy-duty response equipment around the release area.

Figure 2 - CO_2 Blowout Case History – Blowout Location Ingress/Egress under SCBA Visibility cloud *[Courtesy of Wild Well Control]*

CO_2, when dissolved in water, forms carbonic acid. Although this is considered a relatively weak acid in small, and short-term concentrations, it can cause corrosion of equipment over longer periods of time. Only in high concentrations is carbonic acid considered harmful to humans, causing respiratory issues or eye irritation. In a blowout scenario, it is possible that this carbonic acid will be ejected from the well, either when the CO_2 is mixed with kill fluid or when the CO_2 mixes with the existing formation water. This can then "rain" out on the location and is something that has to be factored into response risk assessments.

CO_2 in its solid form (dry ice) can be present in depressurization events such as a blowout scenario. The solid CO_2 can form downhole in the well, if pressures dictate, or on surface equipment in and around the release area. The most likely area for formation during a controlled well control circulation would be on a choke manifold or at any orifice, which reduces the pressure of the CO_2, causing it to transition to the solid phase. The dry ice is at temperatures of approximately -78.5°C (-109.3°F), which can cause cold burns if it makes contact with exposed skin.

In cases where there is a significant depressurization, there is also a risk that solid pieces of dry ice can be ejected with the blowout flow. WWCI has responded to cases where surface equipment has become frozen (BOPs, choke manifolds, flow lines) and solid pieces of dry ice were expelled from the wellbore – anywhere from pea size to golf ball size and even softball-sized chunks being expelled hundreds of feet into the air. There have also been cases where Underground Blowouts (UGBOs) at shallow casing shoes (~100m) have created freezing temperatures at the subsurface exit point, which froze the water-based fluid in the annulus and the drill pipe. There have been cases where portable propane spot heaters were used to facilitate faster dry ice removal, but this method carries a significant risk should any hydrocarbons be present.

Most CO_2 blowouts to date, in WWCI experience have been in connection to Enhanced Oil Recovery (EOR) projects rather than dedicated carbon capture initiatives. This trend has the potential to change as more carbon capture projects are developed in the coming years. For EOR projects, CO_2 is a very efficient carrier of hydrocarbons, and the injection of CO_2 significantly improves the ultimate recovery of oil. In these cases, during a blowout, it is not pure CO_2 that blows out; it also carries hydrocarbons with the flow, which can increase the risk of flammable, toxic hazards. It is expected that a blowout at a carbon capture well, with freshly injected pure CO_2, would initially return the pure CO_2 along the blowout flow path. However, as the blowout extends over time, there is still potential that remnant trace amounts of hydrocarbons in the reservoir, especially in cases where old oil or gas reservoirs are being used for carbon injection would be carried with the flow. These hydrocarbons may be transported to the surface with the CO_2 flow, creating an ignition hazard around the wellhead or even downwind of the well or in low areas where it can pool. Therefore, some firefighting and/or fire prevention measures (fire water cover, AFFF foam, etc.) may still be warranted, with gas detection monitors set up for all potential hazards as a minimum step.

Figure 3 - CO_2 Blowout Case History – Vapor cloud visibility, freezing CO_2 temperatures

[Courtesy of Wild Well Control]

Operational consideration for intervention between shallow and deep water operations

In an offshore blowout scenario, the water depth and leak location depth will drive the behavior of the CO_2. In water depths greater than ≈1000 m (3280 ft), the hydrostatic pressure of the water at the mudline will be greater than 100 bar. This means that at the mudline location, the CO_2 can only exist in Supercritical, Liquid, or Solid forms. Gas phase transition would occur either in the riser, choke line, or water column, depending on the pressure profile at the time of the event. At depths shallower than ≈1000m with mudline hydrostatic pressures more typical to the North Sea, CO_2 can be in the gas phase at a mudline release point.

CO_2 has a high degree of solubility in water, while natural gas has a much lower solubility in water. This variation of solubility has an impact on the amount of gas we would expect to surface in an offshore release blowout scenario with a mudline exit. The graph below shows a comparison between a subsea gas plume simulation for pure methane release compared to pure CO_2 release. In the presented case, all modeling variables were kept the same, except for swapping the Methane with CO_2 while keeping the mass flow constant. The modeled flow rate was 13.3 Million Sm^3/day (470 MMSCFD) released at the mud line. The graph shows the percentage of the released mass that has reached a given elevation above the seabed. An experimentally validated subsea plume CFD model has been used to generate the plot below.

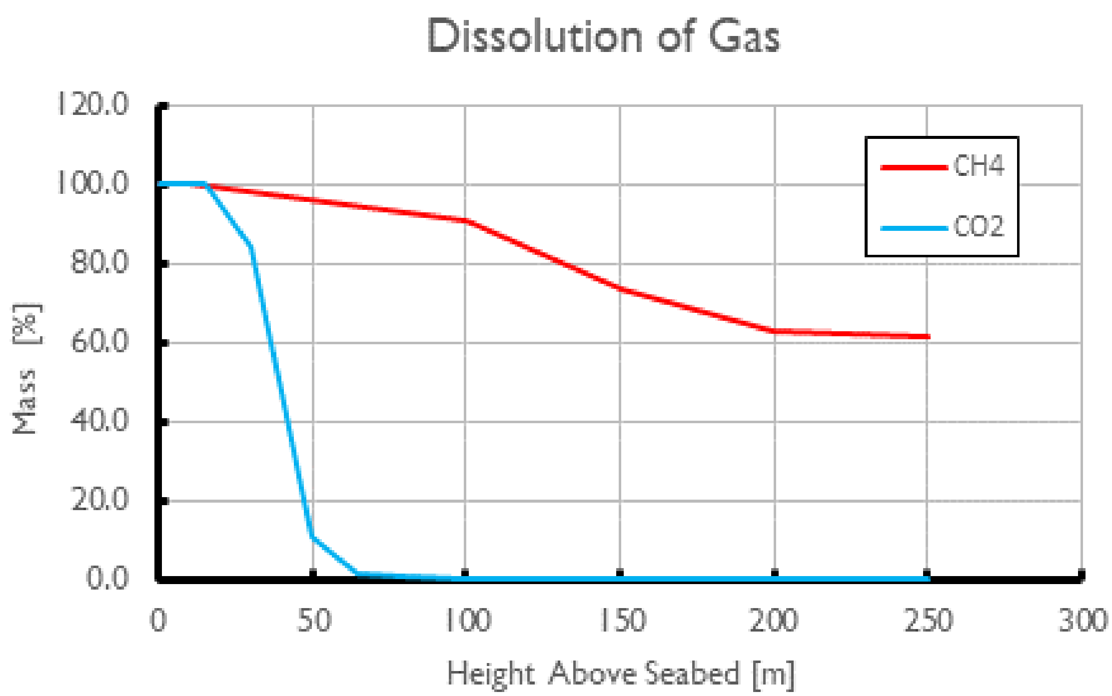


Figure 4 - A comparison between a subsea gas plume simulation for pure methane release compared to pure CO_2 release

[Courtesy of Wild Well Control]

For methane, approximately 60% of the gas reaches the sea surface for the modeled depth of 250m. On the other hand, most of the CO_2 dissolves ~70m above the seabed. These results are indicative of the difference in the solubility of methane and CO_2 (two orders of magnitude). The results obtained from the modelled scenario (and corresponding rates) also indicate that a surface hazard following a subsea release of CO_2 is not likely unless the water depth is very shallow. One can expect to see significant quantities of CO_2 at sea surface only if the subsea release rates was higher and/or in shallower water depth. The exact quantities of CO_2 can be evaluated on a case-by-case basis with validated modeling tools if required, and the results of such models can be fed into pre-planning and response strategy documents.

Well Control Equipment and Subsea Capping Operations

Deployment of a subsea capping stack is one containment option that could be available for a subsea CO_2 well blowout. The configuration of a subsea capping stack in response to CO_2 has some variation from that of a standard oil or gas blowout, mainly in the materials used for the equipment. Metallurgy, as well as elastomers, should be specified for CO_2 operations. The Cameron bulletin below indicates that many seal types are only rated to 5% or 10% CO_2, and timeframes can be as little as 48 hrs. Elastomers such as Buna-N (nitrile rubber) and Teflon are chosen for packers and seals due to their resistance to CO_2-induced swelling.

Note#1 in the technical bulletin from Cameron indicates *the maximum recommended gas bleed rate to be 10 psi/min from 2,000 psi or below*. Experience indicates the highest risk of ram damage stems from rapid bleed-off, which would compromise the elastomers' integrity since the CO_2 doesn't have time to migrate out of the material.

Cameron Elastomer Compatibility with H_2S, CO_2, and CH_4

Elastomer Usage	*Material Specification*	*Immersion Test Method* [2]	*Test Temperature*	*Test Media*	*Exposure Time*	*H_2S Maximum*	*CO_2 Maximum*	*CH_4 Maximum*
High-Temp Ram Packers and Top Seals, Connection Rod Seal	MS-001057	API 6A, 19th Ed., Annex F	350°F	#2 diesel	168 hours	35%	10%	55%
		API 6A, 19th Ed., Annex F	250°F	#2 diesel	168 hours	20%	5%	75%
		API 6A, 19th Ed., Annex F	190°F	10% H_2O	48 hours	35%	10%	55%
		API 6A, 20th Ed., Annex F	190°F	#2 diesel[5]	48 hours	45%	10%	45%
		API 6A, 20th Ed., Annex F	190°F	H_2O[5]	48 hours	45%	10%	45%
		In-Service[4] Performance	190°F	Natural Gas (35% H_2S)	43 days (1032 hours)	35%	5%	60%
	MS-001130	API 6A, 19th Ed., Annex F	350°F	#2 diesel	168 hours	35%	10%	55%
		API 6A, 19th Ed., Annex F	190°F	10% H_2O	48 hours	35%	10%	55%
		API 6A, 20th Ed., Annex F	190°F	#2 diesel[5]	48 hours	45%	10%	45%
		API 6A, 20th Ed., Annex F	190°F	H_2O[5]	48 hours	45%	10%	45%
	Parker Polymyte[6] (Polyurethane Z4651D60)	API 6A, 21st Ed, Annex F	250°F	#2 diesel	160 hours	20%	10%	70%
		API 6A, 21st Ed, Annex F	250°F	10% H_2O	48 hours	20%	10%	70%
		API 6A, 21st Ed, Annex F	180°F	#2 diesel	160 hours	35%	10%	55%
		API 6A, 21st Ed, Annex F	180°F	10% H_2O	48 hours	35%	10%	55%
Bonnet Seal (Seal Carrier)	MS-001110	API 6A, 19th Ed., Annex F	250°F	#2 diesel	168 hours	14%	5%	81%
		API 6A, 19th Ed., Annex F	190°F	10% H_2O	48 hours	35%	10%	55%
Bonnet Seal (Face Seal)	MS-001068	API 6A, 19th Ed., Annex F	350°F	#2 diesel	168 hours	35%	10%	55%
		API 6A, 19th Ed., Annex F	250°F	#2 diesel	168 hours	20%	5%	75%
		API 6A, 19th Ed., Annex F	190°F	10% H_2O	48 hours	35%	10%	55%
		API 6A, 20th Ed., Annex F	190°F	#2 diesel[5]	48 hours	45%	10%	45%
		API 6A, 20th Ed., Annex F	190°F	H_2O[5]	48 hours	45%	10%	45%
		In-Service[4] Performance	190°F	Natural Gas (35% H_2S)	43 days (1032 hours)	35%	5%	60%
Standard Service Ram Packers and Top Seals	MS-001051	ASTM D471-06	180°F	Novatec Oil-Based Mud	168 hours	5%	5%	90%
Annular Packers (Standard Service)	MS-001138 MS-002146							
VBRs	MS-001062 MS-001145							
	MS-002192	API 6A, 21st Ed., Annex F	300°F	H2S Sour Mix 35% / Kerosene 60% / Water 5% (% in vol)	168 hours	20%	10%	70%
Annular Packers (Standard Service	MS-002177	ASTM D471-06	180°F	Novatec Oil-Based Mud	168 hours	5%	20%	75%
Annular Packers (Severe Service)	MS-001141	API 6A, 20th Ed., Annex F	190°F	#2 diesel[5]	48 hours	45%	10%	45%
		API 6A, 20th Ed., Annex F	190°F	H_2O[5]	48 hours	45%	10%	45%

Notes:
[1] The maximum recommended gas bleed rate is 10psi/min from 2,000 psi and below.
[2] Testing is conducted on rubber specimens, such as dog bones, in simulated services conditions through controlled testing. Test results may not give direct correlation with actual part performance.
[3] For Cameron Elastomers not listed, contact Engineering for compatibility information.
[4] In-Service Performance is based on customer reporting rather than standardized test methods.
[5] 10% by volume.
[6] Trademark of Parker Hannifin.

Private

* Mark of SLB

Figure 5 - Cameron Engineering Bulletin 953 D - Elastomer Compatibility with H_2S, CO_2, and CH_4

[Courtesy of Schlumberger]

There are still unknowns as carbon storage well projects progress, but past experience with capping wells on surfaces with high CO_2 content does not indicate there would be significant challenges in regard to capping subsea. The elastomers are expected to experience dropping temperatures below their rating while landing out the capping stack and undertaking any close-in procedure, but the exposure to the temperature reduction is expected to be for a short duration. The low temperatures are expected to return within limits once the BOPs are shut in and flow is stopped. Static flow condition removes the effects of Joule Thompson cooling.

There are some concerns about the lifespan of the BOP elastomers once shut in on a pure CO_2 well. However, an alternative viewpoint is to see the capping stack as a means to access the well and reinstate a permanent or hydrostatic barrier. If a capping stack seal does eventually leak, this issue does not necessarily prohibit the injection of kill fluid in an emergency blowout situation, so long as the majority of the kill fluid remains in the well rather than being lost at the seal leak point. There could also be a scenario where the torturous path created by a failed seal creates a significant pressure drop in the CO_2, causing dry ice to form at the leak point.

In shallow water, with a high blowout rate and in cases where there are CO_2 concentrations at the sea level, offset installation equipment may be required to keep any response vessel out with the CO_2 plume and oxygen-deficient envelope. Existing shallow water well capping systems would allow a capping stack to be deployed offset from a safe location. An example of these systems is the Delmar's HCLS technology. The HCLS technology counters subsea motion, isolating the system from underwater turbulence to create a stable base for positioning the capping stack in shallow waters.

Well Control with CO_2

The method of CO_2 well control is highly dependent on the specifics of the well, with factors such as the CO_2 purity, reservoir conditions at the time of the event, and rig capabilities all feeding into the well control method selection process. Some comments are provided below that are specific to CO_2 well control.

Mitigation – Implement all appropriate well control practices to avoid well control scenarios

- Managed Pressure Drilling (MPD) systems provide a better ability to manage the well pressure profile than traditional mud column circulation. MPD allows the pressure in the well to be quickly adjusted via MPD choke manipulation, and automation can be used to maintain a pressure profile where the phase change conditions for CO_2 are not seen.
- An understanding of the well pressure is critical in managing the CO_2; including a PWD sensor to the drill string would facilitate determining the bottomhole pressure while managing any well control event.
- Specific operational procedures and crew training are essential for CO_2 well projects. Operational experience with CO_2 is limited, and many of the skills, procedures, industry norms, and rules of thumb learned when dealing with natural gas do not apply to CO_2 influxes. It is recommended that detailed CO_2-specific operational procedures are provided. Training for the crew is essential and would ideally take place in exercise or modern simulator format until competency is established.

Operations

- CO_2 has significant solubility in WBM systems. Traditionally, natural gas is considered to have no solubility in WBM and can be expected to migrate. This migration behavior will be different when dealing with under-saturated WBM and a CO_2 influx. Breakout may, therefore, occur unexpectedly if circulations and volume are not suitably controlled.
    - *Additional research is required to develop reliable modeling for CO_2 gas solubility in drilling fluids. Recent SINTEF lab test results (Project Green Light Work Package 2) showed that CO_2 solubility decreases with the temperature for all drilling fluids, while the solubility in Water-based fluids varies significantly between the Water-based fluid batches from the factory and the batches acquired from the field. [Reference: Fen, Linga, N'Gouamba, and Skogestad: Well control for CO_2 wells - Experimental results, September 2023 – March 2024].*
- CO_2 purity has a strong effect on the phase change envelope. A planned CO_2 envelope may change should any impurities be mixed for the flow. The exact composition and, therefore, the exact phase envelope may be hard to determine if an event occurs.
- It may be undesirable to circulate CO_2 using conventional well control, and constant bottomhole pressure methods. In a circulation such as Driller's Method, the pressure of

the influx "bubble" will reduce as the circulation reaches the choke. This reduction in pressure could result in conditions being met for CO_2 phase change, triggering a rapid expansion Joule-Thompson cooling effect either within the wellbore, or across surface circulation equipment. This risk to the operation has to be assessed by the operator, who may alternatively elect to use a method such as bullheading as the primary well control response method.

- Bullheaded CO_2 may experience a pressure drop as it exits the wellbore and enters the reservoir, depending on the completion type and reservoir condition at the time. This may result in a change in bullhead pressure response at surface during the operation.
- Water-based mud systems have been used on CO_2-EOR projects. These WBM systems required carrying additional concentrations of calcium to tie up the CO_2. It was later converted to gypsum-based mud for increased stability. The fluids engineer will have to run a garret gas train to determine when the CO_2 concentrations are increasing to maintain the recommended concentration of excess calcium for system maintenance. If this is kept up daily, there should not be a CO_2 breakout.
- A derrick vent line is designed primarily to expel light natural gas at high elevation, allowing it to rise above the rig floor. CO_2 is heavier than air and has the potential to fall from the derrick vent line exit point, displacing the lighter air on its way back down to the rig floor. An alternative vent line exit point may be required by the operator to mitigate this issue.

Well Integrity and Carbon Dioxide

- Local corrosion risks are elevated in the presence of carbonic acid. CO_2 with water forms carbonic acid. Barriers may be compromised by the corrosion with the potential to lead to a blowout.
- CO_2 wells typically have much more frequent workover operations than conventional wells – especially if the material properties are not adequate. Work on wells that have compromised integrity can be high-risk operations.
- CO_2-resistant materials that stand up to the corrosive nature of CO_2 can be used for critical components and well-control equipment. Alloys such as Nickel, Monel, and stainless steel are used in flow-wetted areas. A particular concern is in congested fields where legacy wells are connected through the reservoir network. The legacy wells, that were previously abandoned may not have been designed with a high level of CO_2 resistance in mind when making material selections. If the CO_2 migrates through the formation to these wells, the long-term effects of CO_2 exposure could result in legacy well integrity issues

Relief Well Operations and Carbon Dioxide

- CO_2 should not have any significant impact on the relief well drilling phases of locating, tracking, and intercepting. An intercept point above the target well (TW) shoe, which is typically set close to reservoir top, may be considered to avoid drilling into a CO_2 reservoir with the relief well. Relief well specialists can advise the optimum design on a case by case basis.
- There might be some considerations to be made relative to kill fluid selection if downhole exit points are creating extremely low temperatures around shallow Underground Blowout (UGBO) points.
- Ranging technologies are not expected to be influenced as they will have limited contact with CO_2 until intersect is made and hydraulic communication established.
- Surface Location Selection
    - Land-based and offshore dry wellhead scenarios - A CO_2 release can produce large, dense clouds with low visibility. The extent and direction of the cloud can have an effect on the relief well surface position.
    - Subsea release scenarios – In most cases, the majority of the CO_2 is expected to be dissolved in the water column. Relief well placement would not be impacted if no CO_2 is present at sea level.
- Dynamic Kill operations will potentially see a highly dynamic response as the pressure profile changes in the blowout well, triggering phase changes. Modeling tools to determine the potential pressure response are critical in the dynamic kill planning phase.

Well Control Capacities (Kick Tolerance) Considerations

Well Control Capacity, or Kick Tolerance, assessments are used in the well construction phase to assess the proposed well design's capability to contain a fluid influx, commonly hydrocarbons, in a well control situation. Calculations are performed to determine the potential exerted pressures in the well, which will be seen while a hydrocarbon influx is circulating out. These pressures can be checked against the expected fracture gradient at a casing shoe or in a weak open hole zone to determine if the influx can be contained and removed in a controlled manner without exceeding fracture limitations. Dry gas is typically selected as the hydrocarbon used in the calculation as it yields the highest pressures due to the difference in fluid gradient between the gas and the circulation fluid. An industry standard influx circulation method, such as the driller's method, is usually selected as the basis for the calculation. Kick Tolerance is a useful and important step in the casing design process and can drive the selection of casing setting points, drilling mud weight, and the use of technology such as Managed Pressure Drilling (MPD) where circulation windows are small or acceptable influx volumes are low.

Kick tolerance calculations can be classical calculations, i.e., Mathcad or spreadsheet-based. However, these calculations are often based on conservative assumptions where gas does not dissolve into solution, effectively treating the influx as a separate single bubble. Classical calculation methods typically fail to fully capture the transient PVT effects on the mud and the influx of hydrocarbon. This can have a significant effect in subsea wells, and HPHT wells where Equivalent Static Density (ESD); the true effective mud weight acting on the well at TD can be very different from the injected mud weight at the surface.

When considering CO_2 influxes, it is important to note that the CO_2 can dissolve in both oil and water and will likely undergo some form of phase change as it makes its way from the supercritical condition at reservoir depth through the well to the surface. As it transitions out of the supercritical phase, there will be density change, strongly coupled with the pressure and temperature changes at the specific point in the circulation profile. CO_2 is also soluble in water at the correct PVT conditions and saturation levels, making its migration behavior vastly different from that of a natural gas.

Within a conventional calculation approach, it is very difficult to capture complex phenomena with a high level of accuracy such as the CO_2 density transition, any downstream pressure wave effects, or any transient density fluctuations that occur due to the phase change. One proposed approach to yield conservative kick tolerance results is to assume the CO_2 is all in the gas phase. While this ensures the maximum volume of CO_2 has been reached, and the highest hydrostatic pressure reduction occurs in the well, the approach also removes the expansion behavior from the calculation. A CO_2 influx in the supercritical phase, when transitioned, will expand rapidly to a large pit gain or volume increase, and this needs to be accounted for to obtain a full picture of the proposed well control strategy.

It is difficult to set one parameter, such as a fixed CO_2 phase or density, and ensure this produces the most conservative results in all cases, and equally, it is unclear if this approach would yield significantly over-conservative results, potentially driving a change in well design where none are required. Kick tolerance is also usually based on a constant bottomhole pressure method such as the Driller's Method, which may not be the well control method of choice for a CO_2 influx. It is for this reason that the industry is driving forward with high-fidelity CO_2 well control simulators that closely resemble the true behavior of CO_2 in a well-control situation to allow appropriate assessments of the preferred strategy to be made.

Note on simulations

Current industry standard simulators are focused on hydrocarbon-based systems with the CO_2 component treated as an impurity. The PVT models and flash calculation methods in the current simulation engines are not applicable for the high concentrations of CO_2. Ongoing JIPs are underway to refine the modeling methods to properly describe the CO_2 migration from the reservoir or influx point to surface. The simulation limitations include:

- PVT of CO_2 in some cases is limited to two-phase: gas and liquid when in reality, CO_2 phase change is more complex and can include dry ice formation.
- The impact of CO_2 dissolution on the mud rheological properties is not well known.
- The impact of CO_2 and impurity, or hydrocarbon mixing in a dynamic well control scenario, is difficult to capture.

CO_2 Well Control Simulation Software

At the time of writing (Q4 2024), industry well control software vendors are working to implement changes to their models, which fully capture CO_2 behavior.

There are multiple commercially available simulation tools on the market (e.g., LedaFlow, OLGA, OliaSoft, etc.). One of the most widely used software for flow assurance and CO_2 injection modeling is SLB OLGA, which is in the process of releasing a separate CO_2 analysis module to its customers. The CO_2 analysis module has completely changed the solver to best suit CO_2 applications. In the standard OLGA software, the user can often find instability and non-physical results when compared to CO_2 cases. This is due to the way the standard solver resolves the Equation of State (EOS), conservation of momentum, conservation of mass, and conservation of energy equations at each time step in a three-step process. The standard solver first solves EOS, conservation of momentum, to determine the velocity and pressure at the timestep. In this first stage, the standard solver does not update the mass or the temperature terms. In the second stage, the solver uses the conservation of mass to update the mass terms only, not updating the temperature term until the third stage, where the conservation of energy is solved and the timestep ends. This process means that the pressure and temperature are decoupled in the standard solver. This is a suitable assumption to make for most hydrocarbon flows where the phase transitional behavior is not as sudden as when dealing with CO_2 phase change but can lead to numerical instabilities for CO_2.

The new CO_2 OLGA solver has been rewritten from the ground up, completely changing the solver process to accommodate the behavior of CO_2. The new CO_2 solver uses a two-step rather than three-step process. In the first stage, EOS and conversation of momentum are solved as with the standard solver, but the new approach also includes energy conservation at this first step. This means the pressure and temperature are coupled, and the pressure behavior is constrained by energy conservation. In step 2, the conservation of mass is resolved to complete the timestep. This process greatly increases the stability of the CO_2 model and results in cases with less unphysical behaviors. OLGA has released data for the solver, comparing it to experimental CO_2 releases in 2017. The instability of the pressure on the standard solver in the initial 10 seconds of depressurization can be seen in comparison with the new solver profile, which is much smoother and matches the experimental trend closely.

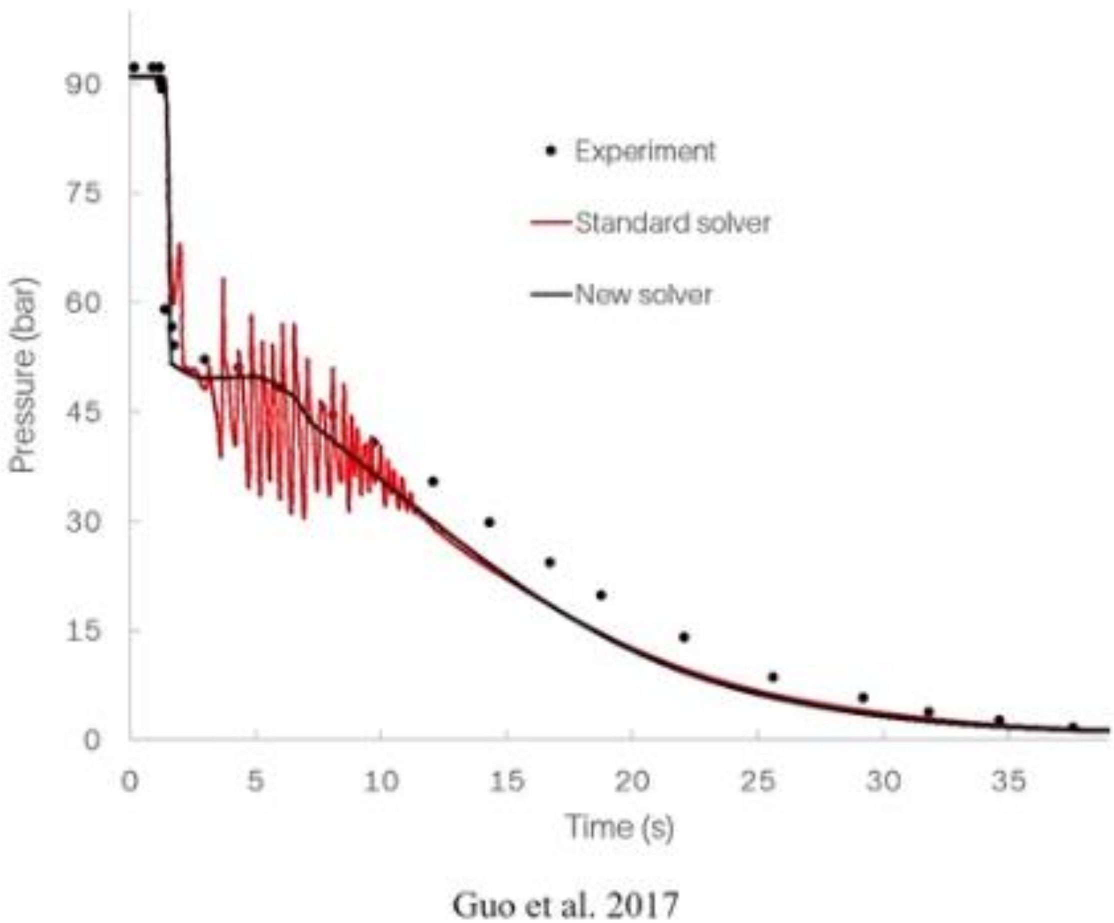


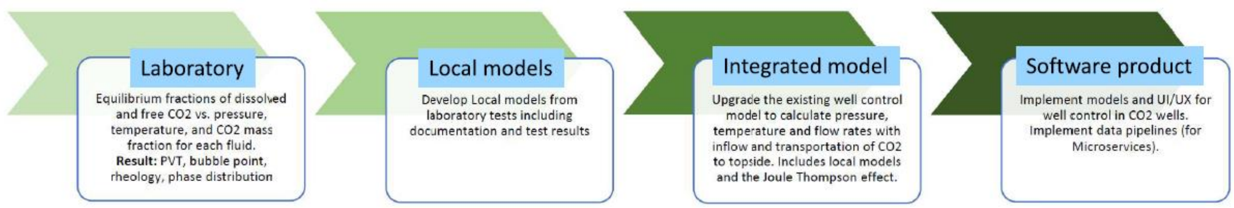
Figure 6 – OLGA CO_2 Solver Data compared to standard Solver Data

[Courtesy of Schlumberger]

Well control modeling, kick tolerance, and relief well dynamic kill models are usually performed in the Drillbench module. At the time of writing, the new OLGA CO_2 solver is not available inside the Drillbench module; it is only available in a full OLGA version. Drillbench is, therefore, currently limited in its handling of CO_2. Custom tab files can be used in the software to approximate CO_2, but this limits its PVT properties during the simulation to a standard two-phase mixture behavior.

Project Green Light

WWCI is currently enrolled in an industry JIP to address knowledge gaps related to well control for drilling into CO_2 storage reservoirs. The JIP is named Project Green Light, and the project leader is eDrilling, who will ultimately implement the updated CO_2 models in their well-control model software. Experimental tests have been conducted by SINTEF, focusing mainly on the alterations of drilling mud properties under varied levels of CO_2 contamination or exposure. Partners on the steering committee include Equinor, ENI, Shell, Transocean, Baker Hughes, EBN, Noble Corp, SINTEF, and GASSNOVA CLIMIT.



[Courtesy of eDrilling and SINTEF]

From September 2023 to June 2024, the laboratory experiments focused on a mix of CO_2 with three commercial drilling fluids: one oil-based and two water-based. A primary goal of the experiments was to evaluate how much CO_2 can be dissolved physically in drilling fluids and how this affects the fluid properties.

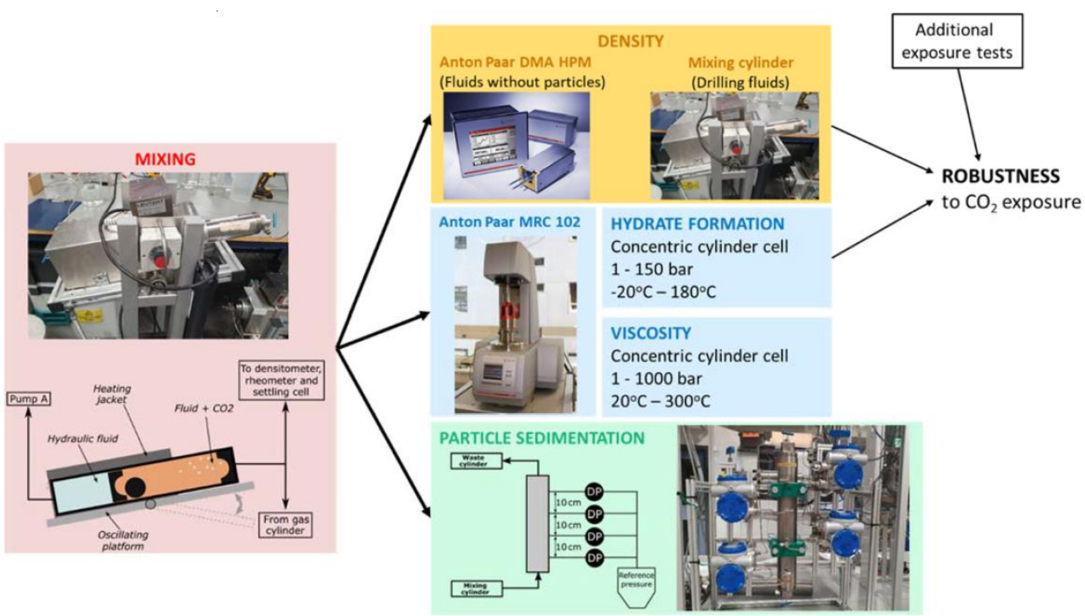


Figure 1: Overview of the experiments.

Figure 7 – Overview of the Green Light Project's Experiments

[Courtesy of eDrilling and SINTEF]

An integrated model has been developed and fitted to the experimental measurements to describe a three-phase equilibrium: a brine phase with dissolved CO_2, an oil phase with dissolved CO_2, and a pure vapor CO_2 phase. This model has been implemented into the software product, e-Drilling. In the software Beta test, users from the partners work to set up and test wells with CO_2, exploring different configurations and CO_2 influx scenarios.

The Beta testing phase of the JIP has been completed late in 2024, with the launch of the first version of the WellControl CCUS module expected in early 2025. The model is still in its early stages and undergoing validation testing and refinements at the time of writing. The WellControl CCUS module is limited to a single well, allowing users to simulate an influx and primary response strategy (well control circulations, etc.). A relief well dynamic kill (RWDK) module is scheduled for development after completion of the WellControl CCUS module in 2025, which would allow the simulation of two interconnected wells, such as a relief well intersecting and killing in the well control software.

Comments on Future Works

The following points are suggestions on how the industry can continue to improve the well control response to high CO_2 concentration CCUS wells.

- Continue developing high-fidelity software that allows unknowns to be tested with a higher degree of confidence. The software, when validated, can allow well operators, drilling contractors, and response specialists to review the potential well control options available to them as a critical step in pre-project and response planning.
- It is recommended that collaboration platforms specific to CO_2 well control best practices are created/continued. The aim of the collaborations would be to share learnings, raise awareness of risks, and improve the industry preparedness, specific to CO_2 well control events.
- OEM and well control equipment manufacturers have a key role as they provide the mechanical barriers to any well control event. Clear and concise documentation detailing equipment limitations and recommended practices should be made available for regulators and operators involved in high-concentration CO_2 projects.
- Training for well control scenarios provides an efficient method to identify gaps in a response strategy in a controlled environment. The goal of any training is to improve the understanding and improve the standard of response should an undesirable event occur.

Figures

Glossary and List of Abbreviations

CCUS	Carbon Capture, Utilization, and Storage
CH_4	Methane
CO_2	Carbon Dioxide
EOR	Enhanced Oil Recovery
EOS	Equation of State
ESD	Equivalent Static Density
H_2S	Hydrogen Sulphide
HCLS	Heave Compensated Landing System
JIP	Joint Industry Project
MPD	Managed Pressure Drilling
OEM	Original Equipment Manufacturer
PVT	Pressure, Volume, and Temperature (Reservoir Properties)
RWDK	Relief Well and Dynamic Kill
SCBA	self-contained breathing apparatus
SINTEF	Stiftelsen for Industriell Og Teknisk Forskning
TW	Target Well
UGBO	Underground Blowout
WBM	Water-based Mud
WWCI	Wild Well Control, Inc.