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Considerations: Well Control during CCS Operations



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Introduction

Currently, there is limited published industry guidance on distinct considerations when constructing and operating wells in CO_2 storage projects.

The number of CO_2 storage projects is expected to increase rapidly, and the properties of CO_2 pose particular challenges for constructing and operating wells in CO_2 storage project areas. Different operational techniques such as influx circulation methods and equipment test procedures may be required, along with personnel training tailored to the detection and handling of a CO_2 influx and in mitigating the Health, Safety, and Environment (HSE) hazards present to response teams.

At present, planning Carbon Capture and Storage (CCS) wells with exposure to CO_2 in the reservoir, or when performing well work, requires additional risk assessment and engineering compared with planning for standard oil or gas wells. Some aspects of modelling, simulation work, operational procedures, and execution may also involve using familiar tools or equipment in non-standard ways. This approach is, by nature, bespoke and less efficient than the use of industry standard tools, routines, and equipment in the planning and constructing of oil and gas wells. The present approach encourages each operator to revisit all plans, equipment, and processes when embarking on new CCS projects.

With decades of collective industry experience in well control, with CO_2 Enhanced Oil Recovery (EOR) floods, including infill drilling and workovers, where CO_2 may also often be at or near supercritical conditions in the reservoir, the industry has developed practices from lessons learned from incidents, near misses, and continuous operational improvements. This experience provides a strong foundation from which CCS-specific well control challenges can be understood, adapted, and safely managed.

IOGP's Wells Expert Committee (WEC) has conducted a gap analysis that identifies risks associated with CO_2 well control. The importance of this analysis is to guide industry efforts to develop comprehensive standards and practices. To structure this work, the project was divided into seven areas, each addressing a key aspect of well control:

1) **Modelling**
2) **Well control methods and kick detection**
3) **Well control equipment**
4) **Personnel safety, competency and training**
5) **Relief well and kill procedures**
6) **Well integrity**
7) **Well intervention**

The purpose of this paper is to identify issues and topics in CO_2 well control that are not currently being addressed by existing industry initiatives (e.g., other industry associations, Joint Industry Projects (JIPs), or Standards Development Organizations (SDOs), and which represent opportunities to enhance the safety of CCS well operations.

This paper is intended for operators, drilling and well engineers, well control specialists, and service companies in the planning, execution, and assurance of well control for CCS wells; and to help them strengthen risk-based thinking and enhance the effectiveness of controls and barriers. This is not an exhaustive list of all controls required to mitigate the risk, rather, it provides a basis for the initial risk assessment.

Properties and challenges of CO_2

One major difference between well control in oil and gas wells and wells in contact with CO_2 is the physical and phase behaviour of the CO_2 itself.

Transporting and geologically storing CO_2 is preferably undertaken with the CO_2 in a supercritical phase. For a given mass of CO_2, handling it in the supercritical phase minimizes the volume of the CO_2 compared to handling as a gas or multi-phase fluid and this in turn maximizes the capacity of the geological storage, and the pipelines, tanks and ships or trucks employed in transport. The critical point of CO_2, where gas and liquid phases become indistinguishable, occurs at 31.1 °C and 73.8 bar, and above this point CO_2 exists as a supercritical fluid, exhibiting liquid density and gaseous viscosity. As a result, the fluid is handled at ambient, not cryogenic, temperatures during transport and injection.

CO_2 is highly compressible, readily dissolved in reservoir fluids and exhibits phase changes if sequestered CO_2 migrates out of a geological storage. When rising up a wellbore as an undesired influx, CO_2 will transition from supercritical fluid to liquid deep in the well, then begin flashing to a two-phase gas and liquid fluid stream midway out of the well, then flash fully to gas at shallow depth, and then expand while approaching the surface. The phase change behaviour results in high volumetric expansion and sudden, rapid, density reduction during flashing which generates strong pressure spikes. The volume at surface may be 250 to 530 times greater than the original influx volume, which is about double the expansion factor of methane, and Joule-Thomson (J-T) cooling of tens of degrees can occur during expansion downstream of chokes or other pressure restrictions to flowing CO_2. The already complex phase behaviour of CO_2 is also sensitive to impurities.

By comparison, methane also exists as a supercritical fluid at typical reservoir depths but expands predictably to gas phase while ascending within a wellbore without violent liquid-gas phase changes and with a continuous density drop and limited pressure spikes. The volume expansion factor may range from 150 to 300 times and while J-T cooling is possible, the severity is lower than observed for CO_2.

Modelling the behaviour of CO_2 influxes being circulated out of the well to surface is more challenging than modelling the behaviour of a comparable influx of methane since a multiphase transient approach is required and requires more details of physical conditions than steady state models which are applicable to gas liberation under familiar 'production' conditions. There are known to be development efforts in progress at the time of writing to address the challenges of modelling CO_2 behaviour during injection and well control operations, and the interaction of CO_2 in oil and water-based drilling fluids.

In addition to the complex and violent phase behaviour of CO_2 migrating out of geological storage up a wellbore, CO_2 is readily soluble in both water and oil-based fluids, making the detection of an influx more challenging than is the case for hydrocarbon influx.

Low temperatures caused by the J-T cooling during CO_2 phase changes combined with free water can lead to CO_2 hydrate formation on or within well control equipment or create an ice layer on the outside of surface equipment in humid environments. This may hinder the operation of critical well control systems and pose a dropped-object hazard to personnel working on the rig floor or around the pits.

Any CO_2 dissolving in or reacting with water may result in a corrosive liquid such as carbonic acid at surface during well control operations, which may impact the safe operation of standard well control equipment or pose a hazard to personnel.

An important aspect to be considered in mixed fluids with CO_2 during injection or kick circulations is that small variations in the content of contaminants in the stream may result in major differences in the phase behaviour of the mixed fluids and bringing more complexity in the planning and execution of the operations. In the case of storage of industrial CO_2, the nature and concentration of contaminants present can vary over the life of the project.

When CO_2 contacts elastomers, it is absorbed and the elastomer swells. Swelling may not compromise the seal, particularly when the elastomer element is seated within the confines of a cavity. However, if the elastomer is depressurized rapidly, the absorbed CO_2 can escape violently, leading to explosive decompression and potential failure of the elastomer element. This risk can be mitigated by managing intentional pressure relief during well operations. Specific modelling of the rate of pressure changes at the locations of elastomers in well control equipment can help to quantify the decompression risk during planned and contingency operations.

Whereas hydrocarbons vented from a well primarily put crews at risk of explosion and fire, a CO_2 cloud vented at surface is not flammable but is heavier than air and presents multiple HSE hazards, similar in some respects to those encountered in H_2S-rich environments. These include toxicity and asphyxiation risks, particularly in enclosed areas, potential smothering of generators due to oxygen depletion, and reduced visibility caused by opaque clouds formed through condensation in humid air. In conventional well control procedures for hydrocarbon wells, kicks are circulated to surface, and gas is removed from the drilling fluid using equipment that vents gas vertically through a line that has its exit point near the derrick crown to minimize the risk of detonation or ignition. However, given the aforementioned risks associated with venting CO_2, relocating this vent line, could significantly reduce those hazards.

Opportunities

The next Section of the paper examines the current landscape of work related to CO_2 well control, highlighting areas where further development may be needed.

At the time of writing, these reflect the opportunities identified by WEC CCS Expert Group, and it is acknowledged that other ongoing industry work addressing related aspects of CO_2 well control has not been repeated here.

1. Modelling

For the purpose of this paper, the goal of modelling is to accurately estimate the behaviour of a fluid as it flows within and near the well. Software simulation tools are used to model production, injection, and circulating operations under steady state and transient conditions including normal and worst-case considerations. Models for various hydrocarbons, gases, muds, brines, water, and mixtures have been refined over many decades and validated by laboratory and field observations, and operational experience. CO_2 has always been a constituent of these models, but only recently has the focus been on fluids that are primarily CO_2 in the complex supercritical phase and scenarios that involve transition from supercritical to atmospheric conditions. The limitations of existing hydrocarbon-focused models to capture CO_2 behaviour has spurred development and fundamental work.

Traditionally, flow modelling grids are two-dimensional with depth and radial position with single values for fluid, tubing, annulus, casing, cement, next annulus, and each additional element to the formation. The multiphase behaviour of CO_2 may require grid refinement with smaller elements within the cross section of the fluid to properly reflect large gradients of property changes across phase transition boundaries.

Work arounds do exist, for example by repurposing simulation tools originally designed for other applications such as flow assurance, or by referring simulation work to specialist third-party vendors or to academia.

A number of Joint Industry Programmes (JIPs) and modelling tool development projects are already underway to validate models of CO_2 phase behaviour and its interaction with other common drilling and formation fluids, contaminants to simulate CO_2 influx, blow out, and injection. Current efforts also draw from laboratory work and literature. Unfortunately, modelling success and innovations are hard to share when the developers are competitors. The outcome could be a disjointed industry with multiple products having varying assumptions and optimizations, with each product needing validation and evaluation to be considered as an 'industry standard' tool.

Table 1 – Considerations, risks and recommendations associated with modelling CO_2 behaviour in well environments.

Topic/consideration	Risk and impact	Recommendation
Modelling tools not CO_2 specific	Oil/gas tools may not model CO_2 behaviour accurately.	Develop/adapt/adopt CO_2-specific tools; ensure the selected modelling tools have the capability to model CO_2 adequately. Validate phase behaviour/fluid interactions.
Kick control simulation	Uncertainty due to fluid property assumptions.	Develop CO_2-ready simulation tools; confirm fluid behaviour.
Blowout simulation	Uncertainty due to assumptions on fluid properties, reservoir deliverability, and location of blowout well within plume, all of which affect the resulting blowout.	Develop CO_2-ready simulation tools; confirm accuracy of workarounds.
Casing design simulation	Tools may not include liquid CO_2, or alternative packer fluids used in CO_2 wells, creating uncertainty in simulated density and temperature profiles.	Qualify CO_2-ready tools; develop fluid catalogues for CO_2.
CO_2 solubility/ degassing in fluids	Poor modelling may cause recirculation/loss of hydrostatic pressure.	Model CO_2 behaviour; quantify solubility/degassing; support ongoing research.

2. Well control methods and kick detection

Well control methods and Early Kick Detection (EKD) consider methods of detecting influx as early as possible and the well control responses to influx, managing choke back-pressure to maintain constant bottomhole pressure to prevent additional influx while removing the observed influx volume, with respect to the physical properties and phase behaviour of the CO_2 itself. Considerations include the phase behaviour of CO_2 in the well fluids and at surface once an influx is circulated out of the well.

Table 2 – Considerations, risks and recommendations associated with well control methods and kick detection in CO_2 wells.

Topic/consideration	Risk and impact	Recommendation
Early Kick Detection (EKD)	Failing to recognize an influx of CO_2 into the wellbore while drilling/tripping could lead to substantive entrained CO_2 in drilling fluids. When reaching shallow depths, the entrained liquid CO_2 will flash to gas resulting in a more rapid volume increase than is expected for hydrocarbon influx.	A risk based evaluation may justify supplementing standard kick detection tools—Pressure Volume Temperature (PVT), flow in/flow out monitoring, trip tank monitoring, flow checks, and gas detection with additional technologies (e.g., downhole Measurement While Drilling (MWD) sensors, Coriolis Metering, or Managed Pressure Drilling (MPD)) to ensure timely detection of a CO_2 influx.
Circulating CO_2 kick (CO_2 flash/phase change near surface)	Circulating out an undetected CO_2 kick, when reaching shallow depths, will permit the entrained liquid CO_2 to flash to gas resulting in a more rapid volume increase than is expected for a hydrocarbon influx. This may cause ejection of drilling fluids from the riser and reduction of hydrostatic pressure before Blowout Preventer (BOP) closure.	Model phase changes and volume increases as CO_2 influx is circulated from hole to optimize circulation rates or back pressure to address CO_2 behaviour.

Topic/consideration	Risk and impact	Recommendation
CO_2 phase behaviour during kick removal	Common well control practices that bring an influx to surface introduce complications when the influx contains CO_2 due to the phase behaviour and corrosive nature of CO_2 affecting well control equipment. Standard well control simulation tools do not account for CO_2 phase behaviour during well-control scenarios and hence conditions for the well control equipment are poorly defined. Also, selected drilling fluids may be incompatible with CO_2, leading to extremely low temperature and/or hydrates whilst circulating out a CO_2 influx.	Consider bullheading the influx where possible, rather than circulation to surface. Perform modelling on circulating out a CO_2 influx to surface to understand expected operating conditions for surface well control equipment. Engineer drilling fluids for CO_2 compatibility. Flushing and cleaning well control equipment after handling influx and inspection after operations.
Rapid CO_2 expansion creating CO_2 hydrate	CO_2 phase change to solid may block equipment; pressure/ temperature changes critical.	Perform modelling to quantify the risk of choke blockages resulting from solid formation (dry ice or hydrates) during CO_2 expansion across the choke; ensure mud/ fluid compatibility.

3. Well control equipment

The physical properties of CO_2, its phase behaviour, and interactions with other formation and wellbore fluids lead to potential impacts on well control equipment, and its operation, which are unusual when compared to typical oil and gas fluids. It is important to define the scenarios for well control equipment design and the operating philosophy e.g., what volume of kick considered, pressure, effluent type, circulation circuit, etc.

Table 3 - Considerations, risks and recommendations associated with well control equipment in CO_2 wells.

Topic/consideration	Risk and impact	Recommendation
CO_2 compatible Blowout Preventer (BOP) elastomers	Loss of seal integrity due to swelling, rapid gas decompression, or low temperature if CO_2 incompatible elastomers are used.	Specify CO_2-resistant elastomers (TFE/P, HNBR); conduct compatibility testing; consider frequent change-outs.
BOP, well control equipment and wellhead material selection	Prolonged exposure to CO_2 and carbonic acid may cause corrosion and material degradation.	Improve understanding of corrosion risks; use buffering or scavenging agents to working fluids; consider compatible materials or cladded components; implement post-exposure inspection.
Rapid shut-in and secondary BOP	CO_2 influx may expand rapidly when reaching shallow depths, the entrained liquid CO_2 will flash to gas resulting in a more rapid volume increase than is expected for hydrocarbon influx and challenging response time and seal effectiveness.	Analyse shut-in dynamics; compare CO_2 and conventional wells; consider alternative shut-in strategies.

Topic/consideration	Risk and impact	Recommendation
Low temperature rating well control equipment	Phase transitions and J-T cooling may embrittle equipment.	Confirm temperature ratings; inject MEG/methanol as needed; ensure redundancy; avoid movement and risk of impact, assess the need for supplemental heating—such as heating elements or thermal blankets. Model circulating out a CO_2 influx to understand the temperature, pressure, rates of change, and fluid composition as the influx passes each component.
BOP sealing/ shearing under low temperature	Material embrittlement may prevent effective sealing/cutting.	Modelling of conditions during circulation. Combine low-temperature validation with shear/seal tests for CCS wells.
Choke manifold design	CO_2 can form dry ice, expand rapidly, erode equipment, or cause plugging. Lower temperatures increase risk of hydrate formation downstream of choke and consequent plugging.	Assess choke manifold risks in planning; use low-temperature/ corrosion-resistant materials; consider MEG/methanol injection. Risk-assess the value of additional equipment redundancy (2nd or 3rd choke).
Pressure and temperature sensors	CO_2 may interfere with calibration, causing false readings.	Understand impact of CO_2 on existing sensors, retrofit CO_2 compatible sensors where required. Ensure calibration in relevant conditions. Awareness training for operators and decision-makers that non-rated sensors may read bad numbers during and after exposure.
Fluid separation/ Mud Gas Separator (MGS) sizing	CO_2 influx may challenge standard separation equipment due to volume and properties of CO_2 liberated.	Study MGS sizing, design and metallurgy for CO_2 fluids.

Topic/consideration	Risk and impact	Recommendation
Location of vent line	CO_2 may settle around rig, creating unsafe conditions.	Conduct site-specific dispersion modelling; consider vent line location and safety measures. Refer to relevant Hydrogen Sulphide (H_2S) experience and practices.
Hydraulic fluids for BOP/wellhead	Low temperatures may affect hydraulic fluid performance and system responsiveness.	Model circulating out a CO_2 influx to understand the temperature, pressure, rates of change, and fluid composition as the influx passes each component. Select low-temperature-rated fluids; verify compatibility.
CO_2 impact on grease	CO_2 may dissolve or alter greases, impacting well control equipment reliability such as gate valves.	Ensure grease selection considers the risk of CO_2 induced degradation or changes in grease performance.
Gas readings for all influx gases	Influx may also include contaminants such as H_2S, methane, which could affect phase behaviour, corrosive conditions, and overall safety requirements.	Verify that the BOP meets applicable compatible material requirements to ensure compatibility with the potential corrosive environment. Also considering potential contaminants and assess fluid-movement and intervention thresholds accordingly.

4. Personnel safety, competency and training

Personnel safety considers the impact of CO_2 on the safety of personnel working on the wellsite along with the training and procedures/standards governing their work, particularly in the case where CO_2 or products of the interaction between CO_2 and other formation or wellbore fluids are circulated to surface during well control operations.

Table 4 – Considerations, risks and recommendations associated with personnel safety, competency and training for CO_2 wells.

Topic/consideration	Risk and impact	Recommendation
CO_2 gas at surface: Displacement of atmospheric oxygen	CO_2 is toxic and displaces oxygen, posing risk by: • Being present in closed environments; personnel are overcome by CO_2 with symptoms such as confusion, dizziness, loss of consciousness, and eventually respiratory failure. • Asphyxiation of personnel and oxygen starvation of generators. • Ingestion in pressurization systems for manned habitats and accommodation.	Refer to relevant H_2S experience and practices. Use of CO_2 detectors in manned areas. Provision of breathing apparatus. Risk assess the use of degassers, diverters, and venting equipment, modify as required; directing extracted gas away from manned areas and generator intakes. Conduct dispersion modelling.
CO_2 gas at surface: J-T Cooling	J-T cooling may freeze surface equipment, causing: • Cryogenic burns • CO_2 Hydrate formation • Fog • Slipping hazards	Use degassers and diverters which vent CO_2 away from manned areas. Inject methanol upstream of choke. Use new choke designs.

Topic/consideration	Risk and impact	Recommendation
CO_2 well control: training	Underestimating complexity in CCS reservoirs increases risk. Specific considerations are: • CCS specific well control content • CO_2 solubility in Synthetic-Based Mud (SBM)/Oil-Based Mud (OBM) may affect well control • Standard Blowout Contingency Plan (BOCP) may overlook CCS-specific risks • Intervention in high-pressure CO_2 wells poses specific hazards	Updated training should address: • Personnel involved in CCS operations should undertake specific training in CCS including hazard awareness. • This does not replace well control training. Influx circulation simulator drills that accurately model circulating out a CO_2 influx to understand the temperature, pressure, rates of change, and fluid composition as the influx passes each component. • Train for alternative methods (e.g., bullheading) avoiding CO_2 expansion/venting at surface. • Develop CCS-specific BOCPs covering all aspects. • Provide certification/training for re-entry operations.

5. Relief well and kill procedures

Relief well considers the impact of CO_2 on the planning and execution of relief wells. Killing operations on wells blowing CO_2 are expected to require high kill rates and the phase behaviour of CO_2 in the stream, and the interaction of CO_2 and other formation and killing fluids, may differ from typical oil and gas well fluids, leading to opportunities to optimize planning for and execution of relief well operations.

Table 5 - Considerations, risks and recommendations associated with relief well and killing procedures in CO_2 wells.

Topic/consideration	Risk and impact	Recommendation
Relief well pumping and dynamic kill capacity	Insufficient pump rate or pressure capacity may prevent effective dynamic kill of a CO_2 blowout.	Model and simulate relief well kill requirements, including CO_2 phase behaviour; assess pump rates, pressures, rig, and surface iron limitations; plan for additional pumping capacity (e.g., vessels or trucks) as required.
Bullheading method	Increased bullhead pressure may degrade nearby wells/cement.	Simulate responses to influx using validated or CO_2-adapted models. Include bullhead pressure in plume simulation/modelling.
CO_2 behaviour and kill modelling	Inaccurate modelling of CO_2 phase behaviour and blowout rates may result in underestimating kill requirements or prolonging kill operations. Dissolved CO_2 in drilling fluid may flash during post kill circulations more readily than in the case of hydrocarbons, lowering hydrostatic pressure and provoking additional influx.	Simulate CO_2 phase transitions and blowout rates using validated or CO_2-adapted models; verify kill effectiveness and confirm the well is dead and entrained/dissolved CO_2 is effectively removed from fluid post-kill.
CO_2 blowout: surface effects	CO_2 blanket may affect response effort.	Model plume and weather effects for operations planning. Plume dispersion may require surface location to be farther from blowout well.

6. Well integrity

Well integrity is defined as the presence of envelopes of barrier elements that prevent the unwanted migration or flow of fluids. Barrier philosophy typically considers redundancy as part of containment risk assurance. CO_2 storage projects must consider the possible effects of CO_2 on the barriers as well as the operating and barrier philosophies to mitigate leakage risk.

Table 6 - Considerations, risks and recommendations associated with well integrity in CO_2 wells.

Topic/consideration	Risk and impact	Recommendation
Appropriate/As Low As Reasonably Practicable (ALARP) leak rate	Acceptable leak rates may differ for CO_2 wells.	Industry to risk assess CO_2 specific hazard to personnel, equipment and environment compared to risk associated with leakage of hydrocarbons. Consider higher tolerable leak rates, for example through valves during verification tests; review in As Low As Reasonably Practicable (ALARP) / Best Available and Safest Technology (BAST) context.
Annulus pressure management	Large temperature and pressure variations between injection and shut-in, especially early in the well life. If well is operated without applied annulus pressure (to minimize maximum pressure during shut-in), tubing leak permits CO_2 into A-annulus risking corrosion of casing tubulars. Bleeding off pressure may cause CO_2 release/corrosion if a tubing leak has occurred.	Maintain A-annulus pressure higher than injection pressure. Consider nitrogen blanket in A-annulus to manage pressure variations. Mitigate corrosion risk with packer fluid formulation which inhibits formation of carbonic acid. Discuss prevailing regulation pertaining to continuous monitoring.

Topic/consideration	Risk and impact	Recommendation
Packer fluid compatibility	Selected fluids may cause, exacerbate, or mitigate corrosion, freezing, or losses.	Check compatibility, including sensitivity of corrosion resistant alloys to specific brines; model temperature; develop practices specific to CO_2 well design and operation. Assess which new or existing fluid formulations are appropriate or advantageous for use in CO_2 wells.
CO_2 leakage past cement	Swelling shale may provide an annular barrier element which can complement cement. Studies show that when CO_2 migrates through micro-annuli or cracks in cement, it reacts with cement phases to precipitate calcium carbonate, which can progressively seal the leakage path.	Use bond logs to confirm shale bond on swelling shales which have been qualified as a barrier for a field.[1,2] Evaluate whether the selected cement system can self-seal CO_2-related micro-annuli through carbonation or other healing mechanisms.[3]
Downhole Safety Valve (DHSV)	Low temperatures may affect Surface-Controlled Subsurface Safety Valve (SCSSV) performance.	Define SCSSV specifications early; address qualification gaps; consider check valves as alternatives.
Temperature effect	Temperature changes may affect wellbore/caprock stresses.	Evaluate CO_2 temperature along wellbore/caprock; model for normal and transient conditions and impact of injected CO_2 flowing along top of storage unit/base of caprock causing cooling and reduction in minimum horizontal stress of caprock.

[1] Van Oort, E., Juenger, M., Aldin, M., 2022
[2] Williams, S., Carlsen, T., Constable, K., 2009
[3] Wolterbeek, T.K.T., Snippe, J.R., Hangx, S.J.T., 2024

7. Well intervention

Well intervention considers the impact of CO_2 specific to well intervention operations. Many of the topics or considerations already listed by the equipment, methods, personnel, and safety and well integrity sub-chapters are equally valid for well intervention, however the use of specialist equipment or activities over live injection wells introduces some topics not already addressed by well construction related sub-chapters.

Table 7 - Considerations, risks and recommendations associated with well intervention in CO_2 wells.

Topic/consideration	Risk and impact	Recommendation
Reservoir stimulation/acid job	Chemical reactions may be different to those in oil and gas wells and may create unfamiliar hazards or corrosion.	Prevent bringing fluids to surface; test intervention fluids for compatibility before deployment in CO_2 wells, develop CO_2 specific intervention practices.
Greasing of Pressure Control Equipment (PCE) during wireline	CO_2 may degrade grease, causing seal loss or stuck cable.	Use CO_2-compatible grease; ensure material compatibility.
Testing Subsurface Safety Valve (SSSV)	J-T cooling may freeze valve or form hydrates.	Simulate CO_2 behaviour during tests; design procedures accordingly.
General well intervention operations	Handling of CO_2 or CO_2-contaminated fluids from injection, bleed-off, circulation, or clean out operations may create safety hazards or corrosion.	Develop site-specific procedures and preparations. Consider placing a nitrogen blanket to avoid exposing pressure control equipment directly to CO_2 and perform pressure testing with N_2 instead of water to avoid carbonic acid risks.

Conclusion

The considerations that have been captured in this paper provide discussion points for the industry to support a more aligned approach to CO_2 during well control. The considerations outlined across modelling, well control methods, equipment, personnel safety, relief well planning, well integrity, and intervention highlight areas where further technical development, validation, and operational guidance would benefit the industry. Challenges arising from the presence of CO_2 during drilling and well operations which can be addressed by alternative existing procedures, tools, equipment or engineering, are not discussed in this paper.

Accurate modelling of CO_2 phase behaviour during kick circulation, blowout flow, and during routine well design and workover operations is the first step towards assessing the temperature, pressure, CO_2 state and concentration environment that equipment and well elements will be exposed to during those events.

While many conventional oil and gas well control principles remain relevant, the behaviour of CO_2 introduces additional complexities. Factors such as rapid phase change, extreme volumetric expansion, J-T cooling, hydrate and CO_2 hydrate formation, corrosion, and material compatibility which can affect well control event and how they are managed safely.

Existing well control practices provide a foundation for addressing CO_2-specific well control challenges, subject to appropriate adaptation to account for the unique behaviours and risks associated with CO_2.

Recognizing there are ongoing Joint Industry Projects (JIPs) and other industry initiatives, these considerations serve as additional foundations for future collaboration for the industry, with the aim to improve safety during CO_2 well control operations as CCS projects continue to expand globally.

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