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Material Selection Analysis for Well Design Candidate for CCS/CCUS Project

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Abstract. As the world in ambition to limit the increment of global temperature not reaching as high as 1.5˚C, Production and consumption of oil and gas currently account for over half of global greenhouse gas emissions associated with energy use. Carbon sequestration is one of crucial element of clean energy transition since this technology contributes to both directly reducing emissions in high energy intensity economic sectors and removing CO_2 to balance emissions that cannot be avoided.

Making the opportunity of Indonesia's G20 Chairmanship, PERTAMINA leads the opportunity to establish the carbon sequestration project in nation. With the spirit of synergy and collaboration with partners, technical aspect and technologies are being studied and simulated in order to help decision makers to decide appropriate action and affordability of carbon sequestration project.

It is important to understand not only the subsurface structure of the field itself but well integrity to ensure that CO_2 will able to inject and stays underneath for the intended period of storage take a critical consideration not only in safety but cost parameter. Material including casing, tubing and or other tubular goods points on how will the well last. This paper will using case study method by analyzing and mitigating corrosion of well material. As corrosion as material may degrade with time depending on the downhole temperature, pressure, stress conditions, and formation fluids. CO_2 is very corrosive when it encounters aqueous environment and driven by high pressure, temprature, flow rate, and pH, will react with cement and steel resulting in carbonation which can lead to steel rusting. In addition to rusting, it has possibilities to form cracks on well structure and cause the leakage of CO_2.

In consequence, several factors had to be considered, including the choice of material. Selection of wellbore material play an important role in reducing the risk of corrosion. Strarting with the evaluation of corrosion causes (from partial pressure of CO_2), low life cycle cost, design (including impact of water's and gasses' like SO_x, NO_x, O_2, and H_2S appearance), availability, mechanical and physical properties of material. The results of this study are well design and materials that should have been used, based on the case study that had been done. By utilizing ferrous or non ferrous metal, and selection of composite and polymer are alternatives to decrease the possibilities of corrosion. Additionally, corrosion caused by the presence of sulphur gasses can be avoided by using a protective layer like iron sulphide film. Regardless of the wellbore material, well needs to be on steady state condition in order to maintain well and CO_2 condition.

Keyword(s): Casing, CCS/CCUS, corrosion, material selection.

1 Introduction

Considering the climate change that has been one of the biggest concerned on this planet, Paris Agreement clarified about the importance of limitation on increasing global temperature not as high as 1.5˚C. Thus limitation could have been achievable by decreasing emission of CO_2 for about tens Gt/year (IPCC, 2018), one of which is by using the Carbon, Capture, (utilization), and Storage (CCS/CCUS) technology. In general, CCS/CCUS is the injection and capturing carbon (e.g. CO_2) utilizing sub surface storage site supported by the geological condition of the site. The carbon that had been injected can be captured permanently (CCS), or stored to be utilized by changing the form of carbon to be valuable products (CCUS). In addition to the CCS/CCUS advantages, it is important to observe its components such as well design and materials, as will be discussed on this paper.

Well design is very crucial if we mention about the health, safety, and environment (HSE) aspect (Marbun et al., 2021). Appropriate design of well was intended to mitigate any failure, such as corrosion of well material that potentially occur by the appearance of aqueous environment and forming carbonate acid (H_2CO_3) which is very corrosive (Li et al., 2019). That corrosion reaction might lead to loss (leakage) of CO_2 either from cracks or any wellbore failure. Besides the HSE aspects, the design of well was considered from the availability of materials. Thus, could also related to the economical aspect on a certain life cycle cost.

According to those statements above, it is clear that well integrity risk assessment is needed for injection or production well, especially in Indonesia. Indonesia, which is still in a “compiling phase” of the CCS/CCUS project’s regulation and require several standards, particularly on a technical aspect, like for the production or injection well design and material. Even in worldwide, there are no spesific standard for the CCS/CCUS well. In order to improve the CCS/CCUS project in Indonesia, the risk assessment is needed to indicate the consequences through risks that potentially happen on the wellbore. Subsequently, the International Standard Operation (ISO) and other standards from hydrocarbon injection and/or production well, that will be mentioned, could be applied as a prevention and mitigation of the well failure on the CCS/CCUS project.

2 Methods

Below the list of typical inputs to be considered to provide proper material selection:

- **CO_2 stream composition** (mainly H_2O, O_2, NO_x, SO_x, H_2S, CO, H_2): clear impact on corrosion and CO_2 stream phase diagram. A worst-case composition shall be assessed, especially when commingled streams coming from two or more sources are mixed together.
- **Operational window** as expected range of temperature and pressure is key to determine the formation of free water or strong acids. This window shall not be limited to expected conditions in steady state, but shall also include transition phases as commissioning, shut-in and restart.
  - **Minimum temperature** in case of shut-in or during injection of dense CO_2 in depleted well: it will have clear impact on material toughness performance required.
  - **Maximum temperature and pressure** will impact localized corrosion and stress corrosion cracking at bottom hole.
- **Formation water composition**:
  - Chloride content will impact localized corrosion of high alloy steel.
  - Bicarbonate will impact in situ pH.
- Specified Minimum Yield Strength **(SMYS)** is the pipe mechanical strength required by well design to guarantee the integrity of the completion. Yield strength level may be limited in

sour environment.

These following standards (Table 1) are the main references that are used on hydrocarbon exploration wells and applicable for material selection candidate on CO_2 injection and production well. References that internationally has been used to mitigate the risks that potentially occur when injection or production phase on hydrocarbon exploration's well. Identification and analyzation of the risks comprise the existing and/or new wells. The existing or even new wells also need an assessment based on standards below to ensure the nonappearance of leakage between casing and cement.

Table 1. Standards related to the material selection candidate for CO_2 injection and production well.

Overarching Aspects	Capture	Transport	Storage
ISO/TR 27915: Quantification and verification	ISO/TR 27912: CO2 capture systems, technologies and processes	ISO 27913: Pipeline transportation systems	ISO 27914: Geological storage
ISO/TR 27917: Vocabulary - cross cutting terms	ISO 27919-1: Performance evaluation methods for post-combustion CO2 capture integrated with a power plant	DNV-RP-F104: Design and operation of carbon dioxide pipelines	ISO 27916: CO2 storage using enhanced oil recovery (CO2-EOR)
ISO/TR 27918: Lifecycle risk management for integrated CCS projects	ISO 27919-2: Evaluation procedure to assure and maintain stable performance of post-combustion CO2 capture plant integrated with a power plant		ISO/TR 27923: Geological storage of CO2 injection operations and infrastructure
ISO/TR 27921: CO2 stream composition	ISO/TR 27922: Overview of CO2 capture technologies in the cement industry		ISO/TR 27926: CO2-EOR - Transitioning from EOR to storage
ISO/TS 27924: Risk management for integrated CCS projects			
ISO/TR 27925: Flow assurance			
ISO 17348: Petroleum and natural gas industries — Materials selection for high content CO2 for casing, tubing and downhole equipment			
ISO 15156: Petroleum and natural gas industries — Materials for use in H2S-containing environments in oil and gas production			

3 Analysis of Risk Assessment

Through the identification and analysis of drilled borehole materials (existing well), low-temperature resistance, and barrier of well, can make decisions on materials selection based on thus aspects as in Figure 1. Existing wells and/or new wells would be qualitatively identified, rather from the age, material, or even the environment. Based on Parimal et al. (2021) that had been modified, the assessments of wellbore risk are including analyzing of failure and risk that potentially occur on several risk scope (Tabel 2).

Figure 1. Workflow of material assessment.

Based on the risk assessment bellow, there are 17 scopes that necessarily considered on production or injection well of CO_2. Afterwards, the assessment is being evaluated with risk rating diagram that was obtained from matrix between likelihood and impact of each section or risk's scope (Parimal et al., 2021) (Figure 2). Besides to indicate failure and leaking potential, risk level that had been qualified based on assessment would gave clues to selection of well material. The higher level of section or scope will improve the efficiency in one life cycle cost by indicate the priority of scope that needs to be maintained first.

Table 2. Wellbore risk assessment on several risk scope (modified from Parimal et al., 2021)

No.	Risk Scope	Potential Risk	Causes	Impact/Consequences
1	Well Age	Wells that are in operations for>25 years	- Well deterioration - Casing/Cement deterioration - Wellbore construction practices	- Compromised well integrity - Potential for loss of operating time due to unplanned shut down - Cost impact/remedial workover jobs
2	Wellbore trajectory penetrating CO2 storage & permeable zones below storage	CO2 leakage risk from the CO2 storage reservoir up to the surface Corrosion of casing-cement-formation composite structure	- Wellbore casing may come in contact with corrosive reservoir fluids - Due to corrosion, casing-cement-formation composite structure may get deteriorated	- Compromised well integrity - Potential for loss of operating time due to unplanned shut down - Cost impact/remedial workover jobs
3	Well construction challenges/NPT	Losses Tight hole Lost hole/BHA Sidetrack due to wellbore stability	- Insufficient mud weight - Drilling experience and practices - Wellbore collapse/wellbore stability	- Non-productive time incurred - Sidetrack - Extensive casing wear reducing original casing strength
5	Wellhead	Unable to rig up on well, Material not suitable for CO2 Injector.	- Degraded, Corrosion damage - Wellhead tilted	- Unable to enter and re-complete or P&A operation - Potential for loss of production/injection due to unplanned event - Cost impact/Remedial workover jobs
6	Well head subsidence/uplift	Vertical movement > +/- 5cm	- Tectonic activities, Reservoir compaction, Mechanical failure, Cement failure - Thermal effect - Casing/Conductor corrosion - Fluid migration	- Damage to the grating around the wellhead. Load transferred to the weaker structure. - Casings in compression leading to casing collapse/Cement failure and possible loss of pressure integrity
7	Wellhead material	Corrosion at wellhead, wellhead valves and piping due to corrosive injection fluids	- Corrosion damage - Leaks	- Compromised well integrity - Potential for loss of production/injection due to unplanned shut down - Cost impact/remedial workover jobs
8	Wellbore construction – casing material Conductor Surface Casing Intermediate Casing	Deformation Corrosion damage Leaks	- Mechanical problem encountered while drilling resulting in casing wear and reduced strength - Inadequate TOC across shallow permeable zones - Poor centralization and cemented casing - Casing deformation/cement shrinkage - Remaining casing strength	- Compromised well integrity - Potential for loss of production/injection due to unplanned shut down - Cost impact/remedial workover jobs
9	Wellbore construction – casing material Production/liner casing	Deformation Corrosion damage Leaks	- Non CRA material exposure to CO2 - Degrade cement behind the production casing - Poor cemented casing	- Compromised well integrity - Potential for loss of production/injection due to unplanned shut down - Cost impact/remedial workover jobs
10	Cementing	Sustained Casing Pressure	- Poor mud removal/channels in cemented annulus - Inadequate cement across shallow permeable zones	- Compromised well integrity
		Ineffective mud removal during cementing causing channel		- Potential for loss of production/injection due to unplanned shut down - Cost impact/remedial workover jobs
		(Sustained casing pressure CCP, SCP higher than threshold, PCP lower than threshold)	- Inadequately engineered cement slurry design not considering long term stresses and mechanical properties of set cement - Poor centralization or no centralization - Inadequate cement volume/excess volume of cemented casing - Poor wellbore condition due to excessive borehole breakout or washout - Micro annulus / cement shrinkage - Cyclic wellbore pressures and temperatures; or cement degradation in corrosive environment	- Micro annulus behind casing - Flow behind casing - Casing and cement corrosion
11	Cement material	Non-CO2 resistant/ Class G/ Class H cement will deteriorate relatively earlier than geopolymer/ Slag-flex cement	- Casing in contact with formation due to insufficient centralization - Poor mud properties used used-high PV&YP - Inadequate or no pipe movement - Low pumping / displacement rates - Hole enlargement - Poor Spacer train design	- Inadequate isolation of the overlying formations - Gas channels, and high annulus pressure during drilling and production - Potential well integrity issue

13	Conductor Casing Pressure (CCP) and Surface/Intermediate Casing Pressure (ICP)	Casing annulus pressure, Casing leak Operator's general limits are: SCP and another casing – min between MAWOP & 300 psi PCP – min between MAWOP & 500 psi	- Loss of zonal isolation by cement outside the casing (poor cementing) - Inadequate cement height outside the prod. Casing - Temperature change - Seabed subsidence, Unstable/unconsolidated formation	- Well Intervention is required if annulus pressure increases often after bleeding
15	Production Casing Pressure (PCP)	Casing annulus pressure, Casing leak Operator's general limits are: SCP and another casing – min between MAWOP & 300 psi PCP – min between MAWOP & 500 psi	- Tubing leak/Tubing hanger leak, Packer/Seal Assemble leak - Prod. Csg leak - SCSSSV control line leak into annulus - Temperature expansion due to change in Production /Injection	- Well intervention is required if annulus pressure increases often after bleeding
16	Sustained Casing Pressure	Unable to bleed off pressure or taking long time to bleed off during rig entry.	- Poor previous casing cement bond behind casing - Unable to isolate the source of pressure - Trapped pressure inside casings	- Unable to re-enter the well due to rig unable to approach platform - Hydrocarbon in annulus to surface - Unable to bleed down surface pressure below 100 psi for rig entry
		Unable to proceed for rig entry due to A&B Annulus pressure above 100 psi		- Prolong shutdown, Cost Impact
17	Completion & Completion String Production tubing, tubing hanger, SCSSV, Packers/Gages, Perforated Casing/Liner, Cased hole completion	Npn-CRA materials, damages, leaks degraded cement behind perforation/casing getting corroded	- Acidic condition due to corrosive formation fluid and carbon steel reacting due to corrosive environment - Carbonation/corrosion of Class G cement	- Well intervention required to replace upper completion frequently - Cracks/microchannels in cement - Cost impact/additional time

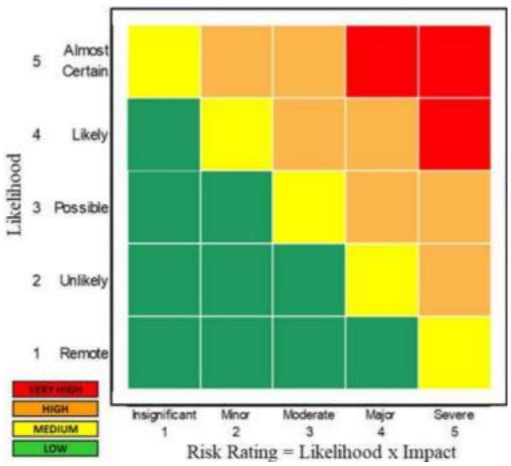

Figure 2. Classification of risk level based on the risk assessment (Parimal et al., 2021)

4 Well Material Selection Based on Assessment

In order to minimize the potential of risk, material selection is very necessary for the injection and production wellbore of CO_2. As it mentioned on Figure 1, identification is required, especially for corrosion risk. Injection of gas, either dry or wet, have a different selection of material. Refered from ISO standards (Table 1), wet gasses is more corrosive when it encounter the aqueous environment owing to low pH and needs carbon resistant alloy (CRA) to avoid the corrosion. Spesific types of CRA are listed on ISO 13680 about CRA for casing, tubing, coupling stock, and other accessory materials. Instead of using CRA, dry gas only required carbon steel or low alloy steel (ISO 17348).

Concerning the appearance of sulphur gasses, materials are written in ISO 15156 which is about all parts of wellbore integrity. Actually, the lab test has not been done for materials selection in the presence of sulfide stress cracking (SSC). Whereas SSC is corrosion that cause cracking of metal by presence of sulphur and water. ISO 15156 also applied for any gasses like NO_x, SO_x, and any contaminant. If we refers to other parameter, corrosivity also influenced by partial pressure. Based on the international standard operation 17348, dry gas injection could only use carbon steel if the partial pressure is higher than 1 MPA. It caused by the condensation of water when it becomes to the transient or upset condition.

If we do the material selection based on the chromium composition of steel, there are at least two aspects that needs to be appraise, which are cost and efficiency. Higher composition such as 25Cr or 28Cr have more capability to the local corrosion resistance but also need more cost. On the other side, 13Cr has less capability to resist the local corrosion, instead it might be more economic rather than 25Cr and 28Cr.

5 Conclusion

CO_2 injection and storage present specific risks related to material corrosion and temperature embrittlement. While material selection rules are well established for H_2S and CO_2 environment, there are significant differences to be considered when injecting CO_2 stream with impurities such as O_2, NO_2, SO_2, CO and H_2. The use of 13Cr material is not recommended in case of low temperature or in presence of impurities due to its low Charpy values but 13Cr material **may be** a cost-effective solution for CO_2 stream with limited impurities and temperature drop while future developments on Equation of State of CO_2 with impurities will be required to predict in-situ condition, corrosion modelling and material testing environments for this application. Finally, extensive testing program is require to define limits of impurities for materials cost optimization and assuring well's integrity. Well integrity with risk assessment is needed for the improvement of CO_2 injection and production activities. The risk assessment would obtain analysis of risk level based on each risk section or scope and could show which priority of well's integrity to maintain and affect the efficiency of one life cycle cost. Besides, the analysis and identification was conducted on risk of corrosion that generally caused by water (aqueous environment). In order to prevent and mitigate the corrosion, it is important to concentrate on material selection. Material selection which had been done was based on several standards that was mention on section 2 (Methods). This study could be a recommendation of the general basis of CCS/CCUS regulation in Indonesia.

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