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# Storage Well Cathodic Protection Comparative Assessment

Daniel Fingas
Corrosion Service Company Limited
9-280 Hillmount Road
Markham, Ontario, L6C 3A1
Canada

Jean-Patrick Boudreault
Corrosion Service Company Limited
9-280 Hillmount Road
Markham, Ontario, L6C 3A1
Canada

Bradley Jefferies
Enbridge Gas
500 Consumers Road
North York, Ontario, M2J 1P8
Canada

## ABSTRACT

The long-term service life outcomes were compared for similar natural gas storage wells operated with either no cathodic protection or partial cathodic protection. Cathodic protection for storage wells is not mandated by regulation and industry practice varies so the outcomes for more than 350 wells were assessed based on casing inspection logs, historical failure rates and service lives. Casing inspection logs indicated a higher prevalence of external corrosion on the wells without cathodic protection. Furthermore, of the wells that had been remediated/abandoned, those operated with partial cathodic protection were found to have increased service lives when compared with the wells operated without cathodic protection. A higher percentage of the wells operated without cathodic protection also required remediation/abandonment. Overall, the data supported a conclusion that partial cathodic protection lead to improved service life outcomes and reduced external corrosion.

Key words: Corrosion control, Cathodic protection, Underground corrosion

## INTRODUCTION

When two long-time operators of natural gas storage wells in southwestern Ontario merged, it was an opportune time for the combined company to evaluate the effectiveness and impact of cathodic protection (CP). Staff from both legacy operators expressed general satisfaction with the longevity of their storage wells, typically 30+ years, but they had relied on two different approaches to corrosion control: one had isolated wells from flowlines and operated without CP, while the second had resistively bonded wells to cathodically protected flowlines. For the second operator, typical well currents were in the range of ~3 A.

Lending weight to the ‘no CP’ approach were internal studies from the 1990’s shared by other storage well operators in the vicinity that had concluded that CP was not beneficial and could even be detrimental. This detrimental effect was attributed either to interference between clustered wells or to current discharge on a single well from one well casing to another, such as from the production casing to the intermediate casing (see Figure 1 for terminology). Based on these interference concerns and well lives exceeding 20 years without CP – which was attributed to conditions not being aggressively corrosive – these other storage well operators had subsequently removed CP from their wells. It was noted at the time that the cost of CP was relatively low and was not a factor in the decision.

Therefore, to determine the optimal approach to CP, the combined company commissioned a comparative assessment on the corrosion outcomes of each of the legacy operators. This comparative assessment was intended to answer two questions: first, whether CP was effective at reducing external corrosion rates; and second, whether the application of CP would be economically beneficial. This paper includes the findings of this comparative assessment.

## LITERATURE REVIEW AND INDUSTRY PRACTICE

### Well Casing Background

A typical well consists of a well head, a conductor casing, a surface casing, one or more intermediate casings, and a production casing, as shown in Figure 1 (note that the maximum depths of the production and intermediate casings is significantly different). Wells are designed so that the casings are not subjected to a pressure exceeding 100% of their respective minimum yield strength, which depend on the grade and weight of the casings, e.g. per CSA Standard Z341.2-18 *Storage of Hydrocarbons in Underground Formations* Section 7.3.2.e.

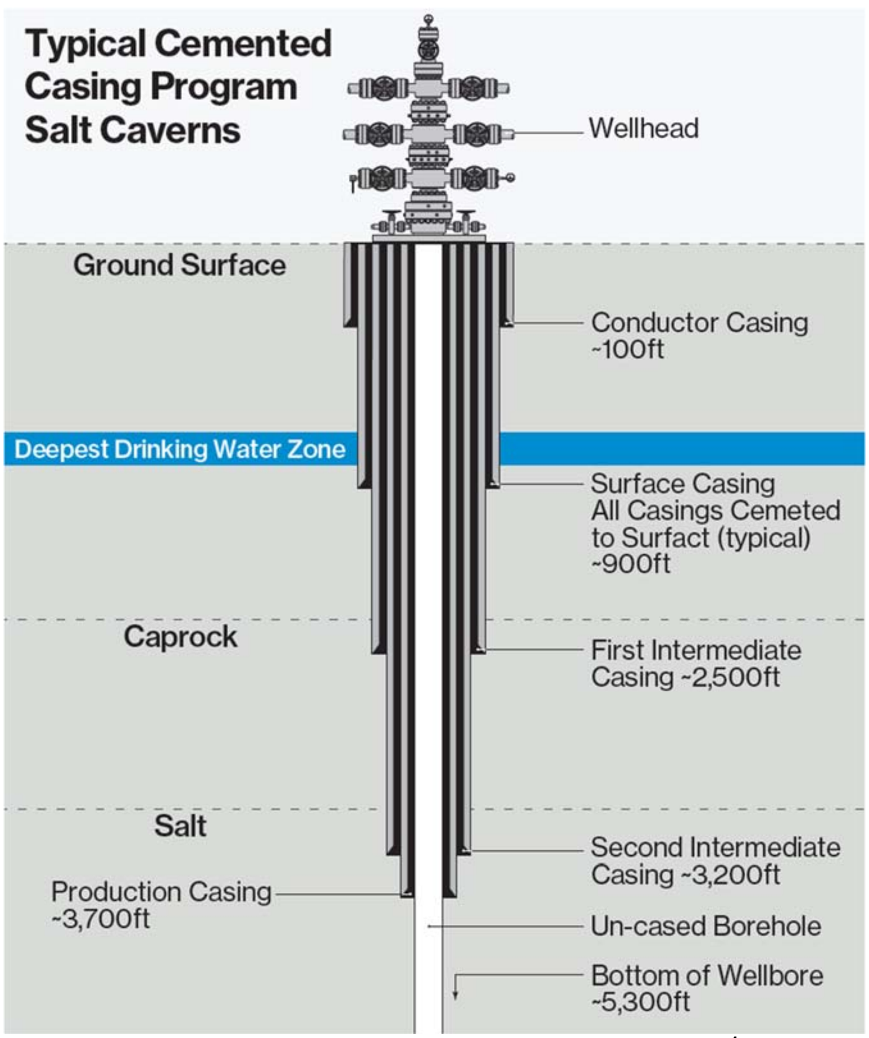



**Figure 1: Typical Well Profile (not to scale)[1]**

Corrosion reduces the wall thickness of a casing, which results in a lower yield strength. As such, operators are required to mitigate and control corrosion.

Corrosion can occur on the internal and external metallic surfaces of the production casing. However, a CP system can mitigate the growth only of external corrosion. Furthermore, CP can only have a direct impact on the exposed portion of the casing, i.e., the portion of the production casing extending past the intermediate casing, since the shallower portion is electrically shielded by the surrounding casings, Secondary effects on the enclosed portions of the production casing are possible and were evaluated as part of this assessment.

**Regulatory Requirements**

The *Oil, Gas and Salt Resources of Ontario, Provincial Operating Standards* require compliance with CSA Z341.[2] Notwithstanding an explicit reference to the 1998 version of Z341, in the latest version Z341-18, cathodic protection is not a requirement. If cathodic protection is used, the user is directed to NACE SP0186.[3,4]

Regulations in other Canadian provinces are generally also based on CSA Z341, although Nova Scotia requires the use of cathodic protection in its *Code of Practice Respecting the Underground Storage of Hydrocarbons*. Z341-98 is specifically acknowledged as the primary source material for the Code, but the preface states that, "Certain requirements are prescribed in this Code that differ from the requirements provided in Z341-98. These requirements are considered to be best management practices within the industry that warrant adoption when underground storage is first developed in the province."[5]

Underground storage facilities in the US are federally regulated under 49 CFR 192.12, which includes by reference API RP 1170 (for salt cavern storage) and API RP 1171 (for depleted hydrocarbon and aquifer reservoir storage).[6] RP 1170 does not address cathodic protection and provides very little guidance on corrosion monitoring.[7] The guidance on integrity monitoring does not include any measurements related to cathodic protection. RP 1171 includes only a recommendation to monitor the "corrosion potential of current flows associated with cathodic protection systems,"[8] which is likely a reference to casing potential logs whereby the net casing current is measured at different depths to assess CP effectiveness.

The Interstate Oil & Gas Compact Commission in cooperation with the Groundwater Protection Council published the Underground Gas Storage Regulatory Considerations: A Guide for State and Federal Regulatory Agencies in May 2017. This informational document states that the use of cathodic protection is a site-specific issue that depends on, "Factors such as the corrosivity of soil and strata above the gas storage zone, the presence or absence of fully cemented casing strings, and the risk of damaging stray current".[9]

Overall, neither the governing jurisdiction nor most Canadian or American regulations require CP for storage wells.

**Industry Practice**

The application of CP for external surfaces of well casings has been established in the industry for many years, with NACE International's standard practice SP0186 first published in 1986. The classic *Handbook of Cathodic Corrosion Protection* by von Baeckmann, Schwenk and Prinz dedicates a chapter to the subject and the references range from 1957 through 1985. This is a helpful overview and includes a discussion of the interference phenomenon for isolated or resistively-coupled casings, with the recommendation that groundbeds be located at least 100 m away from the casings they protect and unprotected casings be even further away to avoid detrimental interference[10].

Regarding the possibility of corrosion due to current discharge from the innermost casing to the intermediate casing on a cathodically-protected well, the statement is made that, "Electrolytic corrosion does not occur in the annular region because of the current flow through electrical connections."[11] This reasoning does not appear to be correct since although incidental metallic electrical connections often do exist between the casings, the resistance between pairs of cemented casings via the electrolytic path is much lower than casing string resistance. This means that the current will substantially equalize between different casings, and this can generally be observed in casing potential logs. Nevertheless, although the reason given may not be entirely accurate, it is likely that the statement is accurate based on long-standing experience.

Oliphant provides a helpful summary of the state of well casing CP in Alberta in the 1980's and updated design guidance[12]. Recent research on the subject of CP for well casings is limited but has focused primarily on enhancing the CP current distribution and reducing groundbed costs through modelling.[13,14,15] The involvement of industry in these papers confirms that CP of well casings continues to be practiced in some parts of the world. Didas provides a case history demonstrating the dangers of inserting resistive bonds of differing values between the rectifier negative and several well casings.[16] This is a variation on the electrical isolation interference problem described by the internal studies from nearby operators

### Summary

The literature indicates that the broader industry continues to rely on CP for well casings in at least some cases, but a thorough analysis of the effectiveness of CP on well casings was not identified. The literature review indicated anecdotally that detrimental corrosion would not occur between casings on a single well, but confirmed the general concern of interference between wells, should the CP system be designed improperly. However, the overall experience of other operators and the continued widespread use of CP indicates the affect is likely beneficial.

## WELL CONFIGURATION AND METHOD

### Well Environment

The majority of the subject storage pool facilities are located in a 1400 km$^2$ area in southwestern Ontario. Although borehole data is not available for each well, the geological composition of the bedrock is relatively uniform in this region.[17] A simplified overview of the geological strata is provided in Table 1.[18]

**Table 1: Simplified overview of geological strata**

| Formation | Description | Thickness (m) | Minimum Depth* (m) | Maximum Depth* (m) | Comments |
|---|---|---|---|---|---|
| **Glacial Till** | clay – particles are finer than 3 millionths of a metre | 20-50 | 0 | 50 | - |
| **Sedimentary Rock** | limestone – mainly calcium carbonate, dolomite | 300-400 | 20 | 450 | -The aquifer is located at the top of this strata.<br>-Typical strata for oil and gas production wells. |
| **Sedimentary Salt** | e.g. sodium chloride | 300-400 | 320 | 850 | -Typical strata for the storage caverns. |
| **Sedimentary Rock** | layers of calcium and magnesium carbonates | 500-700 | 620 | 1550 | - |
| **Metamorphic Rock** | e.g. granite | Unknown | 1120 | N/A | - |

*This depth is approximate and may vary at the location of each well.

The depths of the wells are generally between 400 m and 700 m for the first legacy operator (designated "Operator U") and between 500 m and 700 m plus a cluster around 200 m for the second legacy operator (designated "Operator D").

Based on the proximity of Operator U's and Operator D's storage pool facilities and the uniform geology in the area, the wells are expected to have been exposed to an environment of comparable corrosiveness and the same corrosive layers (if any). As such, geology is not expected to have caused significant differences in the corrosion history of both systems.

The statistical distribution of the drill years for both operators are summarized in Table 2.

**Table 2: Distribution of the Drill Year of the Wells**

| Drill Years | Operator U | Operator D |
|---|---|---|
| **[1900,1960[** | 18.0% | 7.8% |
| **[1960,1980[** | 17.6% | 52.8% |
| **[1980,2000[** | 46.8% | 30.6% |
| **[2000,2020[** | 17.6% | 8.9% |
| **Average** | 1983 | 1979 |

The average drill year of the wells of both companies are comparable, although the Operator D pools have more older wells (i.e., between 1900 and 1980) than the Operator U pools (approximately 35.6% versus 60.7%), which could cause differences in the corrosion history of both systems.

The Operator D wells had no CP system and instead relied on the relatively non-corrosive environment which had resulted in low corrosion rates and reasonably long lives. The gathering lines were cathodically protected using a sacrificial anode system and although it is possible some wells were electrically continuous with the gathering lines, CP levels would still have been very low. Therefore, this is not expected to have significantly impacted the corrosion history.

The Operator U wells and gathering lines were cathodically protected by a shared impressed current system. The wells were electrically isolated from the flowlines using isolating kits but resistively bonded to the flowlines with a typical target current of ~3A. This current is expected to be lower than what would be required based on the E-log I methodology per NACE SP0186-2007 Appendix B, so the Operator U wells were likely only partially cathodically protected compared to the SP0186 approach.

## RESULTS AND DISCUSSION

### General Methodology

Casing inspection has been performed by both operators since 1980 using the downhole magnetic flux leakage (MFL) Vertilog† technique. As part of the analysis, the MFL corrosion indications were categorized as internal corrosion ("IC"), external corrosion at non-exposed depth ("ECN") and external corrosion at exposed depth ("EC").

External corrosion was divided into two categories because along the non-exposed portion of the production (i.e. corresponding to ECN features), CP current cannot directly polarize the casing. Where the production casing is directly exposed to the electrolyte, polarization resulting from CP is expected. The possibility of secondary beneficial effects of CP on even the non-exposed portion of the casing is considered as part of the analysis.

Well life outcomes for the two operators were also compared by examining well workover histories, with workovers defined as repairs/changes to ensure the integrity and suitability of the facility. As part of the workover process, Operator U typically only relined wells (i.e. installed a new, smaller production casing inside the existing production casing) or abandoned and plugged wells, while Operator D also used a backoff technique to remove and replace the production casing near the surface. Workovers attributed to causes other than external corrosion were not considered in the analysis. Note that although the decision to workover a well is often the result of the MFL inspection, which means the workover results are derived from the MFL results, the workover data represents a definitive and expensive threshold for corrosion severity.

†Trade name.

**MFL Results**
The effectiveness of CP was evaluated by considering both the prevalence of corrosion of each category and the category of the most severe corrosion based on the most recent MFL results for each well. Corrosion indications from wells after workovers were not generally considered.‡ The prevalence was considered significant because effective CP would suppress EC indications, while it is the severity of the most severe corrosion which determines whether a workover is required. The effect of CP on the prevalence of ECN indications was not known *a priori*.

Table 3 shows the prevalence, if any, of each category of corrosion. A single well can have corrosion indications in more than one category, so the sum of the indications plus “None” does not match the total number of wells.

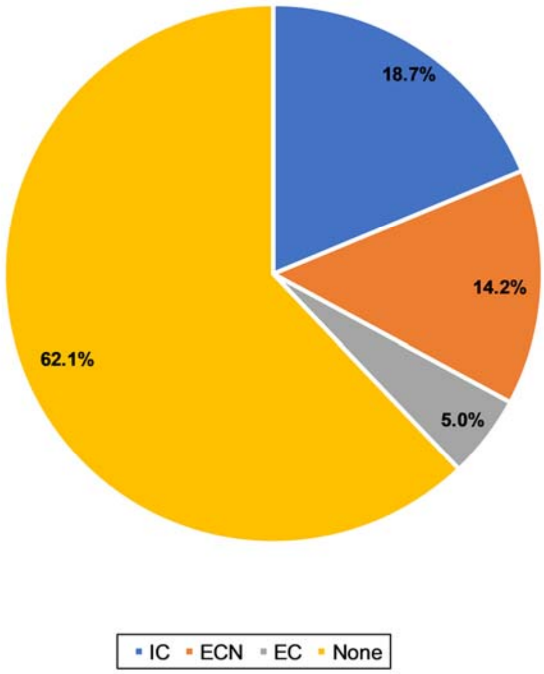
**Table 3: Prevalence of each category of corrosion indication.**

| Company | Drill Year | Total | Corrosion Indication | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | None | | IC | | ECN | | EC | |
| | | # | # | % | # | % | # | % | # | % |
| Operator U | [1960, 1980[ | 39 | 12 | 30.8 | 15 | 38.5 | 19 | 48.7 | 13 | 33.3 |
| | [1980, 2000[ | 105 | 84 | 80.0 | 15 | 14.3 | 6 | 5.7 | 4 | 3.8 |
| | [2000, 2020[ | 43 | 32 | 74.4 | 10 | 23.3 | 1 | 2.3 | 1 | 2.3 |
| | **All** | **219** | **136** | **62.1** | **54** | **24.7** | **47** | **21.5** | **29** | **13.2** |
| Operator D | [1960, 1980[ | 77 | 28 | 36.4 | 22 | 28.6 | 39 | 50.6 | 22 | 28.6 |
| | [1980, 2000[ | 50 | 22 | 44.0 | 10 | 20.0 | 17 | 34.0 | 15 | 30.0 |
| | [2000, 2020[ | 13 | 9 | 69.2 | 3 | 23.1 | 0 | 0.0 | 1 | 7.7 |
| | **All** | **142** | **59** | **41.5** | **35** | **24.6** | **58** | **40.8** | **40** | **28.2** |

IC indications were nearly equal on the two operators, as expected since CP does not impact internal corrosion. EC indications were observed on 28.2% of Operator D wells but only 13.2% of Operator U wells. ECN indications saw an even bigger difference, occurring on 40.8% of Operator D wells but only 21.5% of Operator U wells. These stats indicate a significant reduction in the occurrence of EC indications. This reduction is attributed to the direct action of Operator U’s partial CP on the EC indications. More surprisingly, the stats also indicate a significant reduction in the occurrence of ECN indications. The actual mechanism is not known, although it is speculated that the Operator U’s partial CP may have prevented perforation of the outer casing(s), thereby protecting the production casing from the surrounding environment.

In addition to prevalence of corrosion, each well was categorized by the most severe corrosion condition. The percentage of wells in each corrosion category for Operator U and Operator D are shown in Figure 2.

‡ Corrosion indications identified on wells on which a reline was performed were not considered unless the bottom of the liner extended deeper than the production casing. Corrosion indications identified on wells on which a backoff was performed were considered if they were identified during a subsequent MFL run in the section that was not backed off.



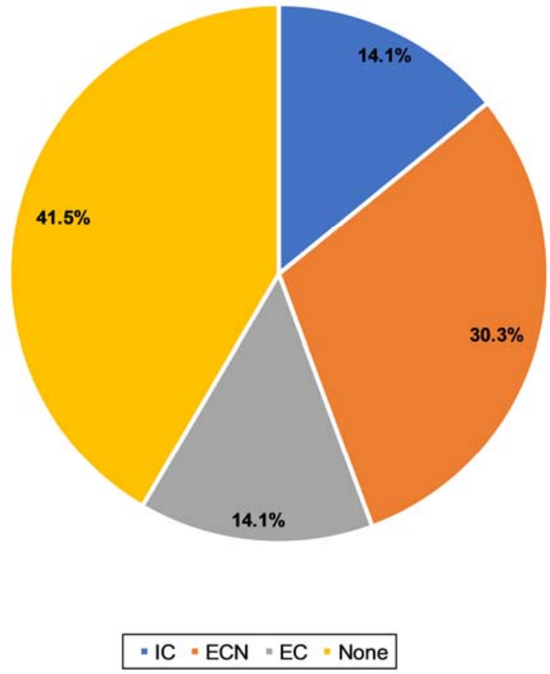



**Figure 2: Category of the most severe corrosion for Operator U (left) and Operator D (right)**

Operator U had a much higher percentage of wells with no corrosion detected, with a corresponding lower EC (-9.1%) and ECN (-16.1%), along with a slight increase in IC (+4.6%), which is discussed below.

To test the possibility that the data was biased by differences in the MFL inspection datasets, the prevalence of IC was also compared. Since IC is not influenced by the presence or absence of CP in a gas environment, the Operator U and Operator D data should be very similar unless there are differences in the underlying data. As shown in Table 4, IC features were detected on the same percentage of each operator's wells (24.7% on Operator U and 24.5% on Operator D), suggesting the datasets are similarly comprehensive and that the impact of differences in installation years is minimal.

**Table 4: Corrosion on wells with IC.**

| Company | Total # of Wells | Wells with IC | | Type of Corrosion Dominant on Wells with IC | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | # | % | IC | | ECN | | EC | |
| | | | | # | % | # | % | # | % |
| **Operator U** | 219 | 54 | 24.7 | 41 | 75.9 | 8 | 14.8 | 5 | 9.3 |
| **Operator D** | 143 | 35 | 24.5 | 20 | 57.1 | 11 | 31.4 | 4 | 11.4 |

Despite the almost equal prevalence of IC, there were a significantly higher percentage of Operator U wells with IC that had IC as the dominant corrosion form (75.9%) compared to Operator D wells with IC (57.1%). This is likely caused by the suppression of EC and ECN indications on the Operator U wells, i.e. with less external corrosion, the internal corrosion is more likely to be the dominant corrosion type.

The accuracy of the MFL measurements has increased significantly over time and the results between runs of the older tools sometimes showed little consistency, so corrosion rate calculations were not attempted.

**Workover Results**

The average time before first workover, $T_{BFW}$, were calculated by averaging, for each operator, the well life before first workover using the formula below:

$$\overline{T_{BFW}} = \frac{1}{n}\sum_{i=1}^{n}(t_{W\,i} - t_{D\,i})$$

*Where:*

$t_W$ = Workover years (years)

$t_D$ = Drill year (years)

$\overline{T_{BFW}}$ = Average time before first workover (years)

Table 5 shows the results of this calculation plus the percentage of each operator's wells subject to workovers.

The average $T_{BFW}$ is an imperfect indicator since, all other things being equal, the time before the first workover is proportional to the wall thickness. This could introduce a bias if the innermost casing of the wells operated by an operator generally had a greater wall thickness than those of installed by the other operator.

For this reason, the average $T_{BFW}$ was supplemented with another indicator, the average corrosion growth rate before the first workover, $CGR_{BFW}$. However, this required the additional assumption that all workovers were performed as soon as the metal loss along the innermost casing was equal to 60% of the nominal wall thickness. This assumption is not valid in general, so the actual average corrosion growth rates are expected to exceed those calculated using this method.

The average $CGR_{BFW}$ were calculated using the formula below:

$$\overline{CGR_{BFW}} = \frac{1}{n}\sum_{i=1}^{n}\frac{0.6 \times WT_i}{(t_{W\,i} - t_{D\,i})}$$

*Where:*

$WT$ = Nominal wall thickness (mm)

$\overline{CGR_{BFW}}$ = Average corrosion growth rate before first workover @ 60%WT (mm/year)

The results of the average $CGR_{BFW}$ analysis are also shown in Table 5.

**Table 5: Average time before the first workover on wells.**

| Workover Type | Operator U | | | Operator D | | |
|---|---|---|---|---|---|---|
| | Percentage (%) | Average $T_{BFW}$ (years) | Average $CGR_{BFW}$ (mm/year) | Percentage (%) | Average $T_{BFW}$ (years) | Average $CGR_{BFW}$ (mm/year) |
| **Backoff** | N/A | N/A | N/A | 16.1 | 28.4 | 0.192 |
| **Reline** | 24.8 | 38.9 | 0.115 | 13.3 | 28.8 | 0.189 |
| **Abandonment** | 5.6 | 48.3 | 0.088 | 13.9 | 33.2 | 0.153 |
| **All** | **30.4** | **40.7** | **0.111** | **43.3** | **30.0** | **0.179** |

The workovers were generally less prevalent on the Operator U wells, with Operator D wells having both more abandonments (i.e., 13.9% to 5.6%) and more backoffs and relines (i.e., 29.4% vs. 24.8%).

The average $T_{BFW}$ was also longer on the Operator U wells for the combination of backoffs and relines (i.e., 38.9 years vs. 28.6 years) and for the abandonments (i.e., 48.3 years vs. 33.2 years). This is corroborated by the average $CGR_{BFW}$ which is approximately 60% higher on the Operator D wells than on the Operator U wells.

**Discussion**

The MFL and workover indicators suggest that the partial CP approach used by Operator U was effective at reducing external corrosion both in the exposed production casing section and where there were one or more surrounding casings. Furthermore, the partial CP approach increased the service life on the wells with workovers caused by corrosion. The analysis could not rule out the possibility that detrimental interference occurred on some wells with partial CP, but the net impact was a significant benefit.

Nevertheless, a CP system would not benefit wells subject to very low corrosion rates and might not provide significant corrosion control benefits after a well is relined since the outer casing(s) are assumed to have already had corrosion perforations.

The possibility of even greater longevity by applying industry best-practice CP could not be evaluated, but it should be noted that failure due to external corrosion remained significant for the partial CP case, so further improvement appears to be possible.

## ECONOMIC ANALYSIS

**Basis for Analysis**

An economic analysis was used to determine whether the increased well lives would be justified when compared to the cost of installing and maintaining CP on the wells.

The service life of the well was used to estimate the time before replacement. For the analysis, a nominal wall thickness (WT) of 14 mm was assumed for the production casing and a reline was assumed to occur once external corrosion had resulted in a metal loss of 60%WT. The average corrosion growth rate (CGR) calculated for an Operator D well, i.e. a well without CP, was estimated to be 0.179 mm/year, while the estimated average CGR for Operator U wells, i.e. those with partial CP, was 0.111 mm/year. The average CGR was used to calculate the baseline time before well relining for both cases.

The data analysis indicated 36% of wells did not show incidents of external corrosion above the 20%WT threshold of the inspection tool and 13% of wells were dominated by internal corrosion. Thus, CP would benefit only a portion of the existing wells (those where external corrosion was measurable and dominant), which was factored into the calculation of the average service life.

**Findings**

Based on the above assumptions, the average service life of a new well without CP was 67 years and with partial CP was 94 years (assuming in both cases the well is relined once to extend its service life). It should be noted that storage well service life is dependent on several external factors and thus the actual service life of an individual well may vary significantly from these estimates. Using a discounted cash flow model over a period of 100 years, the net present cost (NPC) was calculated for the well with and without partial CP. The cost assumptions and total cost over a 100-year period are shown in Table 6.

**Table 6: NPC for a new well with partial CP and without CP over a 100-year period.**

| Approach to CP | Avg. Time Before Replacement (years) | Total NPC of CP Program | Total NPC of Well Reline & Replacement | Total NPC of Well |
|---|---|---|---|---|
| **Partial CP (Operator U)** | 94 | $23,828 | $126,218 | $150,046 |
| **No CP (Operator D)** | 67 | $0 | $278,946 | $278,946 |
| Assumed costs per well:<br>Initial install of CP: $10,000 Well reline/backoff: $400,000<br>Maintenance of CP ($/year): $500 Well replacement: $2,000,000<br>Discount rate (WACC 6% - inflation 2.5%) 3.5% | | | | |

The cost benefit of applying CP to a well already in service was also assessed to identify a break-even point when applying CP would no longer be beneficial from a cost perspective. A linear weighting of the two CGRs (with partial CP and without CP) was applied to account for the service years prior to installation of CP. For a new well the percentage savings in NPC for CP vs no CP is 46%, for applying CP to a 30-year-old well it is 35%, and for a 65-year-old well it is 9%. As the average well life with no CP was calculated to be 67 years, wells older than this would likely be replaced instead of installing CP. Thus, CP is most cost effective for new wells and least effective for wells at their end of life (age 67 years as estimated).

For existing wells, although the cost benefit decreases the older the well gets, the analysis showed that there is a cost benefit to applying CP at any stage prior to the estimated 67-year life of a well with no CP due to the much smaller cost of CP vs. relining or replacing a well. It should be noted that further analysis regarding the efficacy of CP on already corroded wells should be performed as the linear CGR applied over the total service life in this analysis does not account for the complex nonlinear growth rates experienced by individual wells.

## CONCLUSIONS

This study compared a robust dataset of wells operated without CP and with partial CP to evaluate the effectiveness of CP on storage wells.

The analysis of MFL and workover results supported the conclusion that partial CP significantly improved service life outcomes and reduced external corrosion indications and left open the possibility of further improvement using industry-standard CP.

From a cost perspective, as seen by the larger NPC of the well with no CP vs. with partial CP, there is a significant cost benefit to using partial CP.

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