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Dossier

Closure and Abandonment of Oil and Gas Wells
Fermeture et abandon des puits de pétrole et de gaz

Lifetime of a Natural Gas Storage Well Assessment of Well-Field Maintenance Cost

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Résumé — Durée de vie des puits de stockage souterrains en gaz. Évaluation des coûts de maintenance lourde — *Gaz de France* opère sur des puits de stockages souterrains depuis plus de 50 ans. Ces puits ont été forés avec les techniques disponibles à l'époque dans l'industrie pétrolière et gazière. Ces techniques se sont beaucoup améliorées dans les dernières décennies (composition de laitier, opérations de cimentation et de forage, etc.) et la durée de vie d'un puits doit donc être estimée en fonction de l'état d'avancement de ces techniques au moment de son forage.

Ces incertitudes ainsi que les données imprécises sur les puits les plus vieux (logs de forage et spécifications des casings) ont conduit *Gaz de France* à étudier la durée de vie des puits. Deux approches sont présentées ici :

- l'évaluation de la durée de vie théorique d'un puits ;
- le calcul de la durée de vie moyenne de chaque puits en utilisant principalement des scénarios et des cinétiques de corrosion.

La combinaison des deux différentes approches permet de mieux évaluer le vieillissement et la durée de vie restante des puits afin de planifier les meilleures actions (work-overs, abandons) au bon moment.

Une meilleure connaissance de la durée de vie des puits permet un bon suivi des dépenses opérationnelles (OPEX).

***Abstract — Lifetime of a Natural Gas Storage. Well Assessment of Well-Field Maintenance Cost** — Gaz de France has been operating underground gas storage wells since more than 50 years. These wells have been drilled with the current available technologies in oil and gas industry. These technologies had improved a lot in the last decades (slurry compositions, drilling and cementing techniques, etc.) and the lifetime of a well therefore has to be estimated with reference to the techniques in use at the date it was built. These uncertainties and the inaccurate data of the oldest wells (drilling logs and casings specifications) led GDF to investigate the wells lifetime.*

Two approaches are presented here:

- *assessing a theoretical lifetime of a well;*
- *calculating the average lifetime of each well using essentially corrosion scenarios and kinetics.*

Combining the two different approaches, one can better assess well aging and remaining well lifetime in order to schedule the best action (work-over, abandonment) at the proper time.

A better knowledge of well's lifetime enables good control of underground storage operational expenditures (OPEX).

INTRODUCTION

Wells are composed of several concentric steel casings which are the "confinement barriers" in which the completion is introduced.

The external surfaces of these casings are in contact with alkaline cements. The casings are thus in "passive situation" and therefore should not be subjected to significant corrosion phenomena.

However, the sometimes heterogeneous cement medium can be deteriorated by the migration of specific composites coming from the ground electrolytes (chlorides, acid components).

It is particularly difficult to quantify the aging of the cement behind the casings since due to:
– the little information available about the exact composition of the slurry,
– the cementing conditions, which often result in the partial or total absence of cement at some heights of the casing.

The degradation of the cement causes a loss of annular seal and the gas can migrate vertically.

For very particular cases, studies led by *Gaz de France* showed that the mechanical properties and cements seal are not significantly deteriorated by the immersion in certain acid solutions. However the studies are of relatively short term (6 months) and do not cover the range of possible chemical compositions of the solutions, which account for the range of possible rocks in the field.

It should however be stressed that experience so far tends to demonstrate that, clay formations may tighten up with time and fill in the gaps of the cemented structure. However, it is not possible to have these phenomena generalized to every well in every geological structure.

With regards to steel, the hypotheses whereby the loss of metal in the casing is reduced by the presence of cement behind it are confirmed by a number of investigations into corrosion and the efficiency of cathodic protection [1]. Depending on the geological levels to be protected, the consequences of a lack of cement may vary in seriousness. A risk survey is proposed in Section 1, where the descriptions of possible failures and causes associated with them allow an approximate quantitative approach to the influence of the quality of the cemented annular on the lifetime of the well.

As far as the steel is concerned, the initial structure is far more consistent than that of the cement. This facilitates studies into corrosion kinetics, which are nevertheless very difficult to determine accurately in the case of a well.

In terms of mechanical strength, there is no doubt that steel casing offers appreciable safety. The knowledge of the degradation of this barrier with time is essential in order to assess the actual remaining lifetime of the well.

On the same well, several corrosion logging tools have been used. In Section 2, the comparison between all sets of data gives an overview of the difficulties encountered. In the future, with the development of new tools and the increased frequency of measurement, we can hope more progress in the evaluation of corrosion kinetics.

Every wells operator must quantify the maintenance works as accurately as possible, and choose the right moment to replace its equipment. These choices are more and more important as facilities are getting older.

A technico-economical approach derived from the results of the first chapters is given in Section 3. It makes it possible to have a better knowledge of the state of all the wells of one or several storages. Thus it will be easier to establish updated management of the number of operations each year.

1 COMPARATIVE ESTIMATION OF WELL LIFETIME

1.1 Theoretical Lifetime of Wells

Underground gas storage wells have always been drilled under the same technical conditions as oil exploration wells. In the course of time, they have been subjected to the technological changes of the industry and adapted slightly to storage requirements.

The theoretical lifetime of a well is therefore an inaccurate value which is difficult to generalize for an entire field of wells. The first reason was given above (variations of techniques with time) and the second reason is the variety of geological formations from one site to another.

After fifty years of operation, the issue is to determine how many more years these wells can provide the expected productivity while protecting the environment and remaining totally safe.

Today it is difficult to deny the fact that some wells (the worst drilled and completed) are now at the limit of their life as allowed by their initial design. On the other hand it would be absurd to fix a lifetime of fifty years on all the wells, because the observations are somewhat positive on most of the wells, as found during work-overs. It would be equally difficult to prolong the lifetime without giving any explanations.

On the basis of this, and in particular the initial corrosion tests, an assessment of *Gaz de France* well lifetimes has been performed as follows:
– application of an initial theoretical lifetime of 100 years to an ideal well. This first arbitrary value was selected by other industrial cases. It was confirmed by a first calculation with an average corrosion. This ideal and non-existent well is defined as a well in a non-aggressive underground environment where there are neither design faults nor operating problems;
– this concept of the initial theoretical lifetime is difficult to accept by regulations in most countries. Consequently, a risk assessment evaluates an average failure coefficient for each well (between 0 and 1). This coefficient multiplied

by a theoretical lifetime of 100 years gives a more objective assessment of the average lifetime of each well, proportional to the lifetime of an ideal well.

The method will therefore allow the average lifetime of a well to be established as described in the following paragraph.

1.2 Average Lifetime of Wells

Depending on lithographic varieties, depth and natural aquifers located above the storage, well architectures have been defined to isolate zones from one another. Several technical casings give a better seal to the wells while preventing the migration of gas towards the higher formations.

The methodology described here was developed in the particular case of underground storage in natural aquifers. It could be equally well adapted to an oil reservoir or a depleted reservoir, reconverted into storage. The advantage of the approach is, however, closely linked with the durability of the industrial site which will be studied.

The methodology is based on standards and documentation concerning system reliability [2-5]. Started in 2002, it was carried out in steps with many risk analyses performed partly in the United States and usually referred to as "Risk-Based Inspection (RBI)". These studies were the subject of the recommended practices for API [6, 7].

Owing to the particular nature of a well, the methodology cannot always be attached to one of the approaches. However, it is in total agreement with the conceptual definitions of each of them which do not hesitate in recommending their deepening or modification according to the required goal.

The wells are classed according to four different categories, as shown in Figure 1. For each of these categories, a risk-based inspection was carried out to compare the behavior of the wells according to time:

- **Type 1**: The intermediate casing (9"5/8) is very high. The drilling was carried out through all the aquifers until the reservoir. The production casing is thus the only barrier on the upper levels.
- **Type 2**: An intermediate casing (9"5/8) protects the surface aquifer.
- **Type 3**: The intermediate casing (9"5/8) protects all the upper aquifers.
- **Type 4**: The 9"5/8 casing protects the upper aquifers but its shoe is set above the reservoir cover. A 7" liner is set up at the bottom of the well. Moreover, an intermediate casing (13"3/8) also protects the surface aquifer.

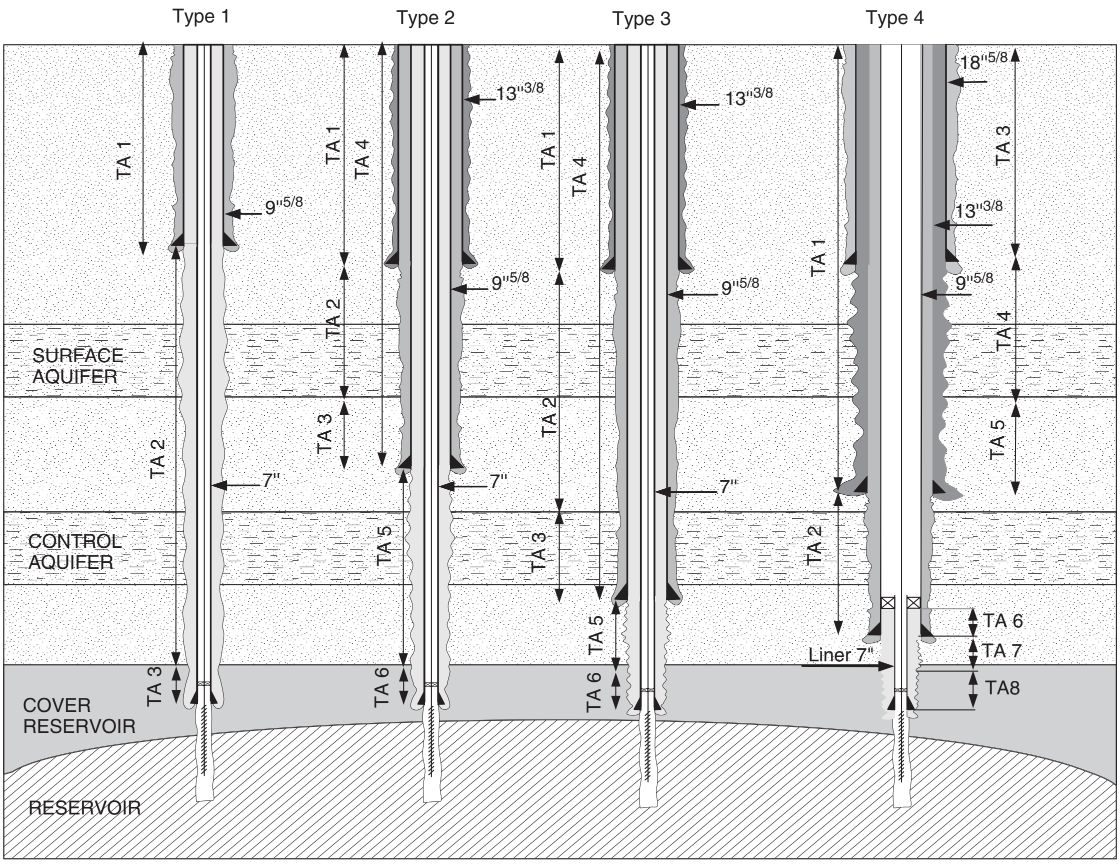

Figure 1

Well categories according to type of architecture.

As shown in Figure 1, the different categories of wells are divided into Technical Assemblies (TA) and defined by cemented casing sections along the vertical axis of the well.

The degradation of mechanical characteristics of the casings with time is evaluated as the possible result of five problems:
– internal corrosion,
– external corrosion,
– casing burst,
– casing collapse,
– leaks at the threaded connections.

During normal operation, it is impossible to accurately diagnose the problem at any given moment and to follow its development according to time. However, it is possible to evaluate, according to the category of wells and the symptoms observed:
– the probable problems,
– all the possible failures that could be associated with these problems,
– the number of Technical Assemblies (TA) that could be affected by these problems.

It will then be possible to evaluate the risk of failure based on the analysis of the causes found in each well and its historical data.

The risk investigation therefore involves five steps.

1.2.1 First Step (PAFM Couples)

For each Technical Assembly of each wells category, tables are established to describe "Problem – Associated Failure Mode" (PAFM) couples.

This gives a detailed description since the number of PAFM couples can be very high, depending on the category of wells (see *Table A1* of Appendix 1).

This concept of PAFM couple becomes necessary because several problems can generate the same failures.

To illustrate this, an example is given in Tables A2 and A3 of Appendix 1, where internal or external corrosion can be the source of identical failures in the event of a casing being pierced (this is shown by a perfect equality between *Table A2* and *Table A3*). A well exposed to both external and internal corrosion is therefore statistically at a greater risk than a well that is only corroded internally. The comparison of these descriptions will allow the distinction to be made.

1.2.2 Second Step (Parameter p_j^i)

As an example, the list of causes considered to be responsible for future cemented casing degradation is as follows:
– acidification,
– salinity and corrosive nature of the formation,
– welds on the external surface of the casing,
– external electrical influences and cathodic protection,
– manufacturing faults,
– design faults,
– operating conditions,
– nature of the formation,
– corrosive nature of the injected gas,
– nature of the annular fluid,
– conditions of drilling, completion and work-over,
– cementing operation of the production casing,
– cementing operation of the last intermediate casing.

All the possible causes of risk inspection failure will then be parameterized.

A parameter "J" influencing an "$PAFM_i$" couple will be referred to as p_j^i.

1.2.3 Third Step (Weighting factor α_j^i)

Every parameter will itself be weighted. Its weigh is related to its estimated influence regarding the lifetime of the well.

The weighting related to parameter "J" will be noted as α_j^i.

Then, for each Technical Assembly, we intersect the PAFM couples described in the tables obtained in step 1 with all parameters influencing each investigated Technical Assembly.

We can continue with the example of Section 1.2.1.

The crossing of the PAFM couples of Tables A2 and A3 in Appendix 1 with the parameters of the "cathodic protection" and "annular fluid" causes, gives the weighting logic described in Table A4 of Appendix 1.

This weighting logic will result in a binary notation of each parameter for each investigated Technical Assembly.

N_j^i designs the note of a parameter "p_j^i":

If a parameter "p_j^i" does not influence the couple => $N_j^i = 0$.

If a parameter "p_j^i" influences a couple => $N_j^i = \alpha_j^i$.

1.2.4 Fourth Step (Failure Average Coefficient λ_{moy})

Analysis of the historical data will then make it possible to gather the best possible information about the initial configuration of a well.

In the same way, the operating data will inform on its behavior in the course of its lifetime.

This will make it possible to give each well an average failure coefficient λ_{moy} such that:

$$\lambda_{moy} = \frac{\sum_{i=1}^{n} G_i \lambda_i}{\sum_{i=1}^{n} G_i} \tag{1}$$

where:

$0 \le \lambda_{moy} \le 1$

n number of *PAFM* couples for the type of investigated well

G_i Gravity of $PAFM_i$ couple and G_i [1;5]

λ_i Failure of $PAFM_i$ couple

and

$$\lambda_i = \frac{\sum_{j=1}^{m} N_j^i}{\sum_{j=1}^{m} \alpha_j^i}$$

with:

m number of parameters influencing $PAFM_i$ couple

N_j^i the note of the parameter p_j^i

α_j^i the weighting factor of parameter p_j^i

With regard to the gravity of the failures was not mentioned previously for the following reason: gravities can be classified by category (maintenance gravity, environmental gravity, safety gravity and availability gravity).

For the maintenance of a well, five levels of gravity can be defined according to the costs of intervention:

- simple actions (*e.g.*, monitorings, pressure readings);
- actions with more extensive procedures and resources (*e.g.*, wire-line);
- more complex operations not affecting the initial configuration of the well (*e.g.*, cleaning of the liners by coiled tubing),
- extensive work affecting the integrity of the well (*e.g.*, work-over for change of safety valve);
- extensive work-over (*e.g.*, restoring of annular section cemented behind the casing).

For cemented casings, the differences described are essentially cases of a very high gravity level (level 5).

If we consider $G_i = 5$, whatever the couple $PAFM_i$, the expression (1) can be simplified to produce λ_{moy}:

$$\lambda_{moy} = \frac{\sum_{i=1}^{n} \lambda_i}{n}$$

1.2.5 Fifth Step (Average Lifetime of the Wells)

The average reliability (complementary to the average failure value) is then multiplied by a theoretical duration of 100 years of a perfect well to obtain the average lifetime of a well.

Applied to the 260 wells located on the four oldest storages, this produces a distribution depending on the average lifetime per 5-year interval, as reproduced in the bar chart of Figure 2.

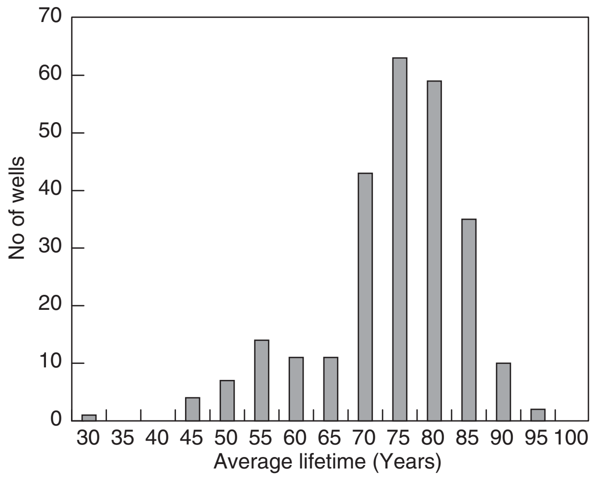

Figure 2

Distribution of wells according to their average lifetime (theoretical lifetime = 100 years).

2 ASSESSMENT OF WELL AGING

2.1 Casing Corrosion Kinetics

The architecture of wells involves complex systems that are difficult to protect entirely. Generally speaking, efficient cathodic protection of a well will protect the external surfaces of the casings in direct contact with the formations. Conversely, inside wells where several casings are involved, several configurations can be considered with cathodic protection influences that are not really comparable. The efficiency of the protection will depend on many parameters (presence of metallic centralizers, presence of cement between the casings, no connection to intermediate casings at well head, etc.).

These major differences in the design of each well (integrated into the risk inspection described in Section 1 will generate discrepancies that will produce local electric chemical phenomena. These phenomena and the associated corrosion kinetics can be very varied (localized or generalized corrosion).

On a conventional, buried structure, it is already difficult to estimate the loss of metal related to external environmental conditions. For instance, for buried gas transport pipes, there is a standard for evaluating the corrosiveness of the soil [8] and the rules for setting up cathodic protection which are already well established. Nevertheless, with time, some defects of coating may exist and, with a deficiency of the cathodic protection, external corrosion kinetics may be included between 25 and 125 micrometers each year.

With the wells, it is very difficult to define a general law for the corrosion evolution in time. However, for the free corrosion of the metal (without cathodic protection) some maximal values could be established based on experimental research. These studies were performed over more than 40 years.

According to a study led by *Gaz de France*, it was estimated that the progression of the major corrosion defects in time could be expressed by a power law which law is given by the relation:

$$P = kt^n$$

where:

P = maximum depth of attack in time t (µm)

K and n are factors deduced of the experiences

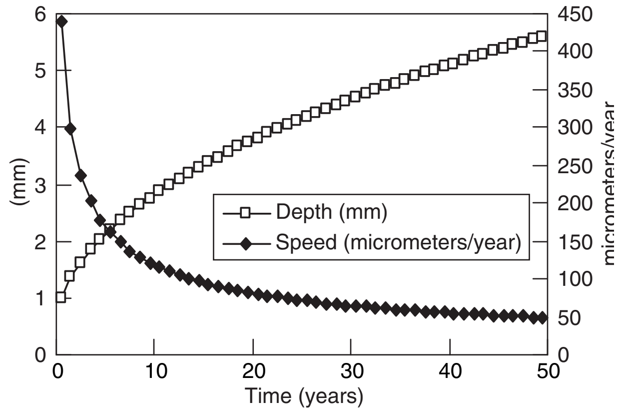

Figure 3

Example of the development of uniform free metal corrosion in the soil.

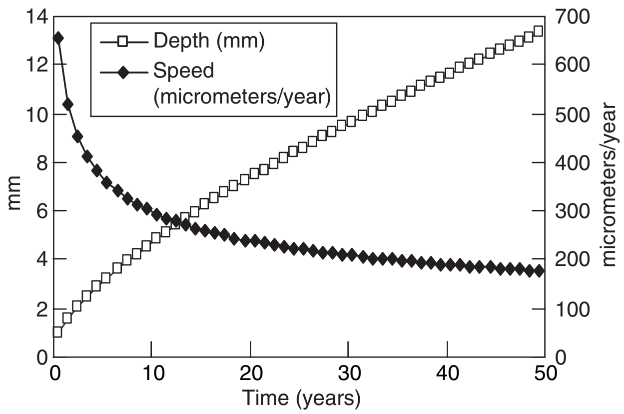

Figure 4

Example of evolution of free localized corrosion of metal in soil.

As examples, two experimental curves are given:

- uniform free metal corrosion *(Fig. 3)* with n = 0.44 and k = 860 µm/(year)$^{0.44}$;
- localized free metal corrosion *(Fig. 4)* with n = 0.66 and k = 980 µm/(year)$^{0.66}$.

This type of law implies very high speeds at the beginning and during approximately ten years, then significant decreases.

If the cathodic protection is set up just after the well is drilled, it considerably reduces these speeds originating from the creation of the structure.

Given these values and the reasons already mentioned (complexity of the architectures, depth of the formation, variation of the water level in the phreatic layers, etc.), it would appear acceptable to consider, in theory, corrosion kinetics included between 50 and 100 micrometers per year for uniform corrosion, and from 100 to 150 micrometers per year for localized corrosion.

These values are probably high. However there remains a strong possibility that they are reached in significant zones with particular circumstances (for example: presence of corrosive electrolytes).

These values will be confirmed with the development of the tools and the increase in measurements.

2.2 Interpretation of Corrosion Measurements on a Well

Recent measurements of a peripheral test well will allow progress to be made regarding the estimated corrosion rates.

These measurements have highlighted the existence of two areas affected by corrosion:

- the splash zone in the cellar, where water-air level fluctuations are considerable;
- a very badly cemented area between the 7” production casing and the 9”5/8 intermediate casing.

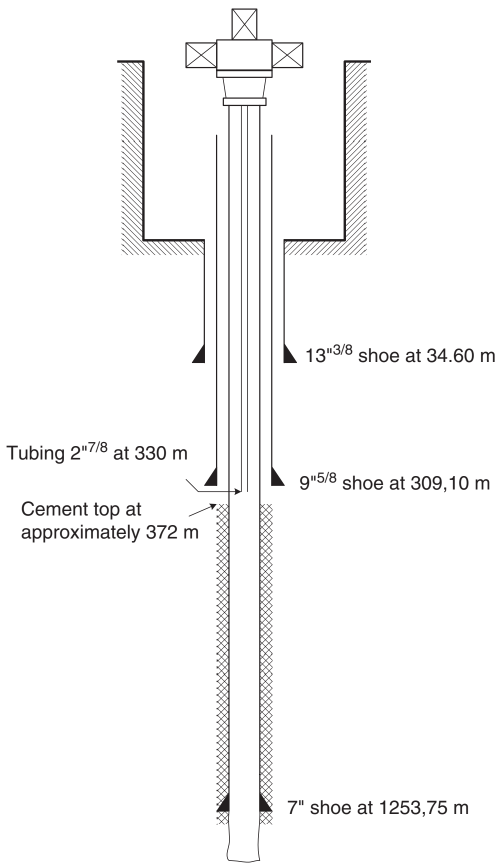

Figure 5

Section of the peripheral well inspected.

A work-over took place on this well. A length of 7” casing (approximately 1 meter) situated immediately beneath the well head, was tested accurately using a laser mapping system. A section cut at 0.2 meter in this area revealed that

there was no extensive internal corrosion. Furthermore, this first inspection confirmed two important points:
- The maximum thickness of the casing is approximately 8.3 mm. Theoretically, this value is above the nominal thickness of the 7” casing at 23 lbs/ft produced by the API tolerance (8.05 mm). This excess is, however, more than justified in the same standard by the maximum tolerance on the weight per meter of the casing. A tube can accept a maximum tolerance of 6.5% on the weight per meter with, locally, extra thickness of approximately 12.5% of the nominal dimension.
- A generalized corrosion over ten centimeters or so (area under well head) and several deep corrosion points with maximum metal losses of 4.3 mm (see Appendix 2).

This initial analysis was completed by thickness measurements on all the production casings, performed with a ultrasonic tool.

In Figure 6, between 3 m and approximately 30 m depth, there is a considerable dispersion of the measurement points and a lower average thickness than between 103 m and 260 m. In this medium area the thickness is near to 8.3 mm.

The analysis of the results of these inspections, carried out under very different operational conditions, removes some of the uncertainty from the measurements.

On the basis of the following data:
- year of inspection: 2004;
- type of casing: 7”, 23 lbs/ft, N80;
- age of well = 37 years;
- average thickness measured in healthy areas during appraisal = 8.3 mm;
- minimum thickness produced by API = 7.04 mm;
- nominal thickness given by API = 8.05 mm;
- minimum permissible thickness according to operating conditions: 3.10 mm.

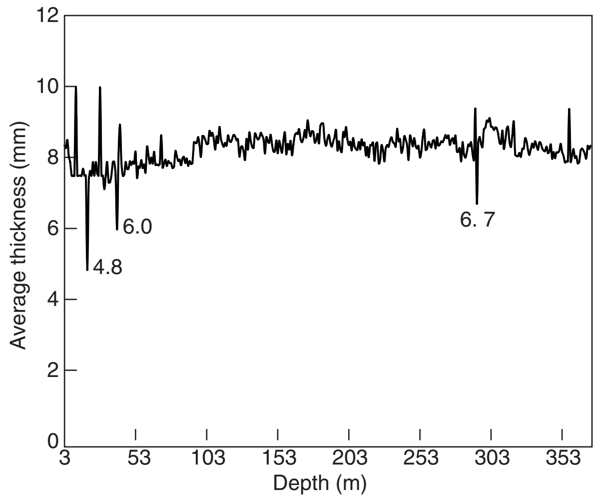

Figure 6

Variation of average thickness by casing section according to depth.

The investigated structures were all protected by cathodic protection, and it is accepted that changes to the corrosion kinetics are more or less linear over the course of time. Consequently, this enables us to evaluate the lifetime of the structure. A summary of the results is given in Table 1.

We therefore confirm that the kinetics are higher for the localized corrosion. Nevertheless, Table 1 shows that the risk of piercing (localized corrosion for environmental gravity), gives lifetimes equivalent to the risk of bursting (generalized corrosion for safety gravity).

Obviously, the values indicated in this table will need to be confirmed during the forthcoming tests inside the wells. There are too uncertainties about the development laws involving metal losses.

TABLE 1

Peripheral test well corrosion inspection

		Initial thickness (mm)			**Initial thickness (mm)**		
		7.04	8.05	8.3	7.04	8.05	8.3
		Corrosion kinetics (µm/year)			**Lifetime deducted from expertise** (µm/year)		
Localized corrosion	**Minimum thickness obtained from laser cartography = 4.0 mm**			116			72
	Minimum thickness deduced from ultrasonic measurement = 4.8 mm	61	88	95	115	91	87
Generalized corrosion	**Minimum thickness obtained from laser cartography = 5.8 mm**			71			75
	Minimum thickness deduced from ultrasonicmeasurement = 5.74 mm	35	62	69	110	79	75

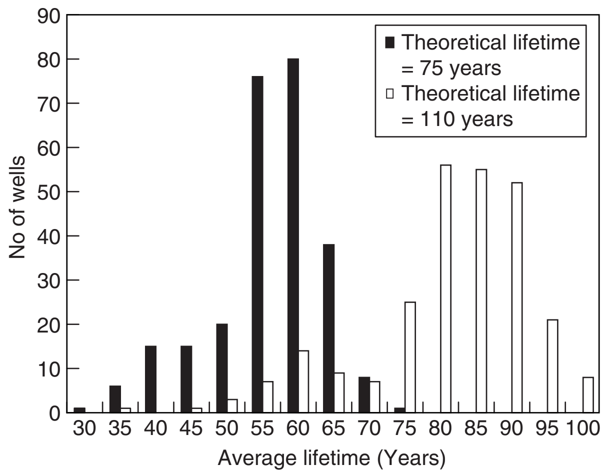

Figure 7

Distribution of wells according to their average lifetime.

However, this expertise enable us to set limits on the occurrence of a casing bursting between 75 and 110 years. On the basis of these two new theoretical lifetime values, it is possible to establish two distributions of the average lifetime of the wells according to their average reliability *(Fig. 7)*.

3 ACTUAL LIFETIME AND ECONOMIC APPROACH

In this document, only the lifetime of cemented casings is discussed. The economic approach in this chapter is therefore not to be considered as exhaustive regarding the operating costs of a well. It excludes maintenance costs in the open holes, as well as the completion and the well head, which will be the subject of other investigations.

The actual lifetime of a well is in fact the result of the technical parameters mentioned in the previous chapters, in addition to regulatory and economical factors. A regulatory change can introduce new identification points and create new operating constraints. This may affect the lifetime of some wells.

The Regulations concerning the protection of drinking water reserves is increasingly stringent. Moreover, maintenance costs are excessively high to repair cemented casings.

In addition, the chances of success operations to restore cemented annulars and better protect casings are low.

Today, with these two considerations it is usual to abandon old wells and replace them.

This solution does not offer only advantages. The abandonment of a natural gas storage well is not an operation to be considered lightly. But it is part of a logical process of the replacement of used production facilities whose operating costs become excessive.

Optimized knowledge of cemented casing aging to better establish the actual lifetime of the wells is therefore essential. However, the age of the wells means that there is a considerable lack of available data about each of them. This makes it difficult to confirm that a decision to abandon is always one hundred percent justified.

When the well is opened for abandonment, another decision can be made. In fact, the measurements of metal loss and of cement aging are performed and the analysis can show that it is preferable to repair the well and to continue its operation rather than to abandon it.

The actual lifetime of the wells is therefore a random variable that we will attempt to establish by successive iterations.

The two approaches outlined in the previous chapters will reduce a number of these uncertainties. The average lifetime deduced from the method described in Section 1 and the estimated aging of the structures deduced from a metal loss calculation as outlined in Section 2, will make it possible to better understand what the actual lifetime of a well is.

If we take into consideration only the abandonment of the wells, proscribing attempts to work over cemented casings for reasons mentioned above, the decision-maker can estimate the development of the operating costs related to the number of operations.

Each year, the corrosion measurements made during heavy maintenance operations will allow new calculations.

The statistical analysis of the average lifetime of the wells will be updated, the field of uncertainties will be reduced and the lower operating costs will allow better management.

Progress in the budget follow-up of the maintenance wells is illustrated by the three following paragraphs.

3.1 Empirical Economical Assessment *(Fig. 8)*

Initially, we identify the drilling date of the wells, to which we add a theoretical lifetime as defined in the first chapter. It is then possible to plot two arbitrary and homothetic curves representing the maximal and the minimal total operating costs depending on the number of operations by unit cost. These two curves represent two extremes cases:

– Dash curve with a remaining period from a well life end 100 years. It corresponds to corrective maintenance and the late replacement of the large number of wells presenting two risks. In the event of disagreement with regulators or many sudden breakdowns, it may be necessary to stop many wells which could reduce storage performances.
– Dot curve with a remaining period from a well life end 50 years. It corresponds to an abusive and an unjustified preventive maintenance causing considerable operating expenditures.

Without using any specific methodology, and in the absence of any studies, it would be excessively difficult to give any idea of the changing total costs of operations related to the closing of deficient wells and their replacement by new wells.

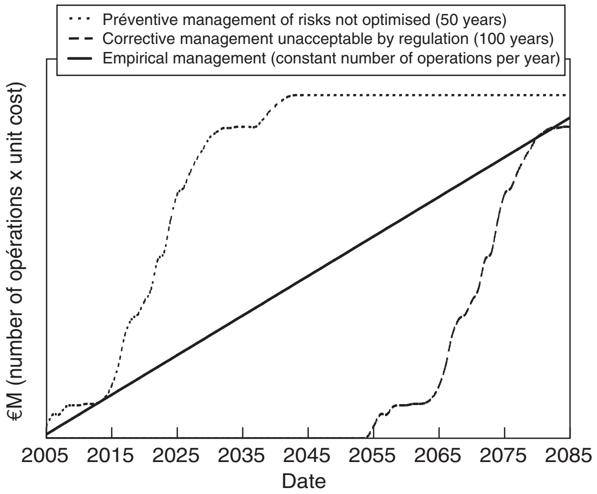

Figure 8

Empirical management of number of operations each year.

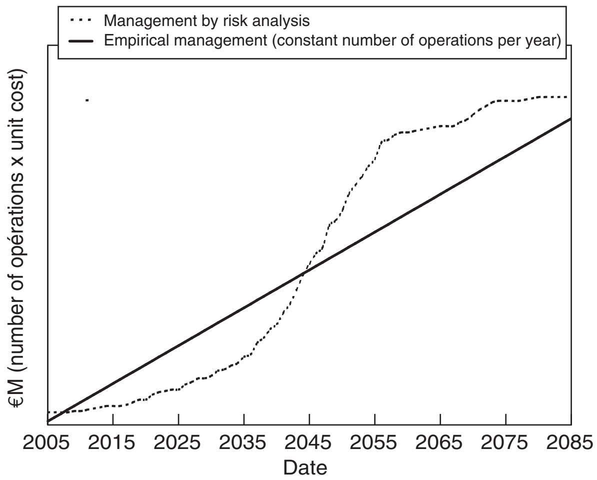

Figure 9

Management by analyzing the risks of the number of operations per year.

The beginning of the Corrective Management curve is at year 2054. But it is difficult to accept not to replace some wells before this date, while the measurements reveal weaknesses in some of the wells.

Furthermore, regulatory demands are increasingly strong and the quantity of maintenance jobs will probably increase.

Because of the considerable increase of drillings in the 1970s and 1980s, a more pessimistic approach would consist in using a preventive replacement policy, coming closer to the dot curve slope (well life end 50 years). This would make it mandatory to perform a great number of operations starting in 2010.

Confronted to this situation, a pragmatic decision would mean cutting the risks and operating costs, and a logical approach would probably be to use a more or less average evolution between the two guidelines (the evolution represented by the full line in *Fig. 8*).

This solution would limit the risks of building up costs at a given period, but is far from satisfactory due to the considerable deviations with the two curves symbolizing two empirical guidelines.

3.2 Economical Assessment Depending on Average Lifetime of the Wells *(Fig. 9)*

Secondly, we considered the average lifetime of the wells established in Section 1. In the same way, the total costs according to the number of wells reaching their life end are given in Figure 9. In this figure, the result gives the same load prediction for 3 operations each year (empirical management represented the full curve of *Fig. 9*). If we reduce the deviations with the average well life end perspectives (dot curve), it suggests that there is a definite improvement in risk management.

However, the deviation between the two curves over the first thirty years suggests the possibility of reducing annual operating costs (slope of full line) by reducing the number of extensive operations per year. But this reduction is risky since the lifetime of a perfect well still stays theoretical.

3.3 Economical Assessment Depending on Actual Well Lifetime

In Section 2, we demonstrated that, on the basis of measurements to be performed in the wells in the forthcoming years, we can improve risk analysis to obtain a more reliable value of the theoretical lifetime.

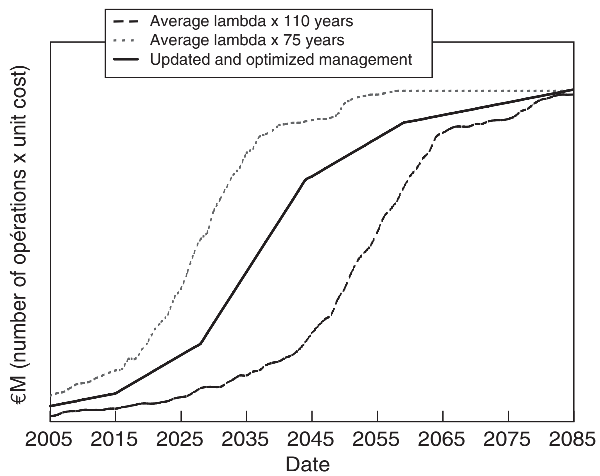

Figure 10

Updated and optimized management of number of operations per year.

The well used as an example in Section 2 suggests frequent risks of piercing of the production casing in the 75 and 110 year time line (see *Fig. 10*).

For each of these values, we can plot a curve representing the accumulated operating costs depending on the number of operations.

These will determine a more restricted field of uncertainties where it will be easier to manage the operating costs while allowing for risk analysis and concrete corrosion measurements.

- **First advantage of this economic evaluation:** this field is far narrower than the field limited by the two curves of Figure 8. This means that the uncertainties are far lower.
- **Second advantage of this economic evaluation:** the risk of the reduction in the operating costs considered in the previous paragraph may be better quantified here. The two limit curves are deduced of field measurements and it is recommended to remain between them at all times.

Accordingly, from year to year, depending on the thickness tests of the materials and knowledge of the wells, we can reset the two limits on the "operating cost optimization" domain to perform updated and optimized management of the well inventory (full curve in *Fig. 10*).

CONCLUSION

The two approaches described in this document will improve precision of lifetime estimates of natural gas storage wells. This method suggests a better management regarding the operating cost forecasts of the wells in the medium and long term.

With the progression of technical knowledge, the domain of uncertainties will reduce. By iteration it will be possible to realign the operation programs and choose the right moment to reduce or accelerate the number of work-overs required each year.

Naturally, the method presented in Section 1 is not exhaustive. In particular, a similar method for the open hole maintenance and to restore the productivity of the wells will need to be developed to further minimize the operating costs outlined in this document.

This management tool must improve essentially with a better weighting of the corrosion parameters. However, at this step, it, gives a initial evaluation of the actual lifetime of the wells, incorporating every technical, regulatory and economic aspect. This approach will make it possible to optimize the planning of work-over and abandonment operations.

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APPENDIX 1

TABLE A1

Number of PAFM couples per well category and per technical assembly

Category	**Number of PAFM couples**								
of wells	**TA1**	**TA2**	**TA3**	**TA4**	**TA5**	**TA6**	**TA7**	**TA8**	**Total**
1	8	25	9						42
2	8	6	6	8	21	9			58
3	8	6	6	8	17	9			54
4	8	17	8	6	6	8	17	9	79

TABLE A2

Failure modes associated with the **internal** corrosion problem
(applied to wells category 1 and Technical Assembly 2)

PAFM couple	Failure mode	Effect of failure produced by ailment in system (Well)	Detectability of ailment and associated failure
$PAFM_1$	Casing piercing. The last sealed barrier to formation above reservoir cover is lost. **Gas migration.**	Trapped gas into formation or into cement can enter the control annular Production well is stopped or particular operating conditions are established	Rising annular pressure Gas in the control annular
$PAFM_2$	Casing piercing at control aquifer level. **Gas migration.**	Entry of gas into control aquifer Possible migration to surface aquifers because the 9.5"/8 casing is shallower	Loss of fluid in control annular Increased annular pressure
$PAFM_3$	Casing piercing at surface aquifer level. **Gas migration.**	Entry of gas into surface aquifers	Loss of fluid in control annular Increased annular pressure
$PAFM_4$	Casing piercing. The last sealed barrier to formation above reservoir cover is lost. **Contact between formation fluid and annular fluid.**	Ionic exchange between fluids which may accelerate internal corrosion phenomena	none
$PAFM_5$	Casing piercing. The last sealed barrier to formation above reservoir cover is lost. **Entry of annular fluid into formation through casing.**	If hydrostatic pressure in annular in front of the hole is high, pressure increase with risk of fracturing at intermediate levels	Reduction in annular fluid level
$PAFM_6$	Casing piercing. The last sealed barrier to formation above reservoir cover is lost. The casing packer is above the reservoir cover.	Entry of gas from reservoir into formation and possibility of migration to shallower levels	None

TABLE A3

Failure modes associated with the **external** corrosion problem
(applied to wells category 1 and Technical Assembly 2)

PAFM Couple	Failure mode	Effect of failure produced by problem in system (Well)	Detectability of problem and associated failure
$PAFM_7$ to $PAFM_{12}$	Identical from case $PAFM_1$ to case $PAFM_6$		

Using tables A2 and A3, we then establish a link with each of the causes presented in Section 1. For instance, as far as cathodic protection and annual fluid are concerned, for each well and depending on the existing archives, we plot the influence or non-influence of all the following parameters:

For cathodic protection

- Influence of nearby protection system
- Influence of reinforced structures of cellar on the cathodic protection of the well
- No. of well casings (including conductor pipe)
- Intermediate casings not connected to the well head at the surface
- Window in casing
- Abnormal section current potential

For the annular fluid

- Nature of completion fluid
- Completion fluid has formed a deposit
- pH of the Initial fluid is lower
- Physical-chemical composition destabilizing for clays
- Absence of anti corrosive treatment

For these two categories of parameters, weighted "cause and effect" relations have been established as summarized in Table A4.

TABLE A4

Example of Links between failure causes on the one hand (Cathodic Protection and Annular Fluid), and PAFM couples into Tables A2 and A3

CAUSE	Ailment and associated Failure Mode	Logic leading to weighting
CATHODIC PROTECTION	$PAFM_1$ to $PAFM_6$	No tie => $N_j^i = 0$
	$PAFM_7$ to $PAFM_{12}$	The cathodic protection must notify external corrosion problems.
ANNULAR FLUID	$PAFM_1$	The completion fluid has an influence on the internal corrosion. The nature and the specific gravity of the annular fluid can support the gas migration.
	$PAFM_2$ to $PAFM_3$	The completion fluid has an influence on internal corrosion.
	$PAFM_4$	The completion fluid has an influence on internal corrosion. Its composition can vary in the event of piercing to accelerate this corrosion.
	$PAFM_5$	The completion fluid has an influence on the internal corrosion. If passage occurs, the completion fluid can enter the formation and cause it to fracture. Therefore, this can only consist of heavily loaded mud.
	$PAFM_6$, $PAFM_8$ $PAFM_9$ and $PAFM_{12}$	No tie => $N_j^i = 0$
	$PAFM_7$	The completion fluid has no influence on external corrosion. But, in the event of piercing, the nature and the specific gravity of the annular fluid can support the gas migration.
	$PAFM_{10}$	The completion fluid has no influence on external corrosion. However, its composition can vary in the event of piercing to accelerate this corrosion.
	$PAFM_{11}$	The completion fluid has no influence on external corrosion. In the event of piercing, the completion fluid may enter the formation and cause it to fracture. Therefore, this can only be heavily loaded mud.

APPENDIX 2

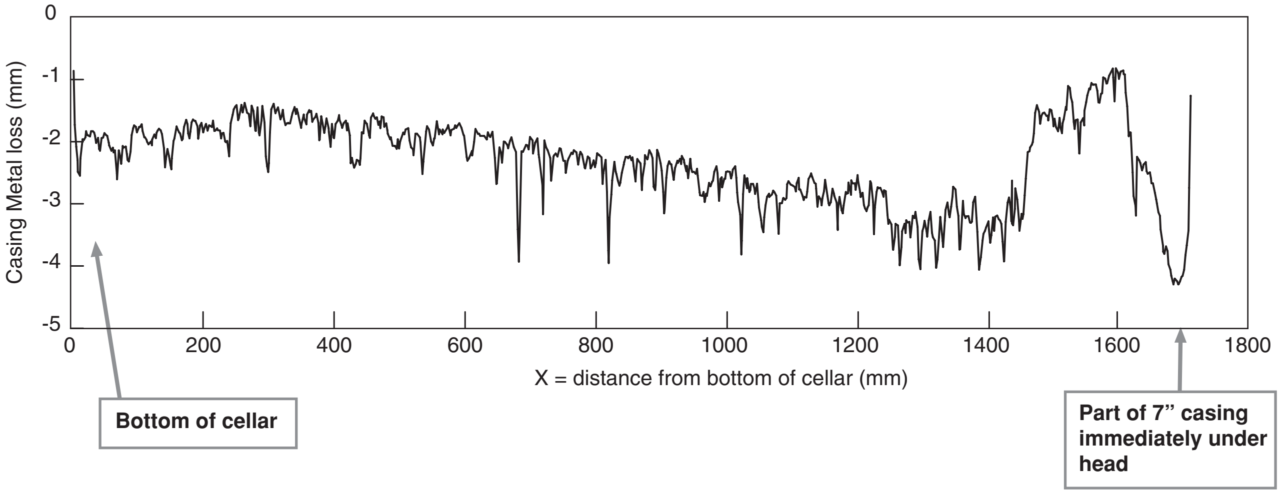

Figure A2

Metal loss measurements on peripheral test well Worst Case X profil.