Recommended practice for change of internal leak rate acceptance criteria

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FOREWORD

After discussion in the Well Integrity Forum (WIF), the decision was taken to establish a recommended practice for change of internal leak rate acceptance criteria.

The manager drilling is responsible for the practice.

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Contents

1 INTRODUCTION

For the Norwegian continental shelf (NCS) API RP 14 B is used as internal leak rate acceptance criteria through selected valves. For gas this is 15 scf/min (0,42 Sm3/d) and 0,4 l/min for liquid.

This acceptance criteria is widely used as an industry practice in Norway, historically developed to be used for DHSVs. The same criteria is also used on other well barrier elements such as ASV, XT/WH valves and completion string components like GLV regardless of knowing if this is the appropriate acceptance level. Same requirement is applied for all well types assets etc. without currently being supported by risk assessments, ref requirement in management regulation §5.

Relevant paragraphs in the PSA regulation referring to the use of this requirement is §48 in the facility regulation which refers to several paragraphs in NORSOK D-010.

But the framework regulation also refers to "§24 use of recognised standards" for fulfilling the regulation. This allows the responsible party to use other solutions to fulfil the regulatory intent of an acceptable safety level, but the alternate solution needs to be properly documented.

2 PURPOSE

This guideline will provide a methodology for evaluating and documenting a change of the internal leak acceptance criteria, instead of applying the API 14B criteria across all assets and well types. The main approach of the proposed methodology is to evaluate any significant change in consequence by changing the internal leak rate acceptance criterion. The assessment will ensure that the various well barrier elements will maintain their function to limit energy supply in an emergency shutdown incident e.g at loss of containment with leak from a well, while maintaining an acceptable state until repair. Significant changes in incident outcome for personnel, installation, environment and normalization due to a change in acceptable internal leak rate through valves is not acceptable, as this does not maintain the risk level prescribed in the regulatory requirements with references to various norms and standards.

This methodology does ***not*** challenge the 2-barrier principle. It gives the means to adjust the acceptable rate through an element while still maintaining the same barrier functionality as is currently accepted by the application of the API criteria.

Since the current regulatory regime accepts a certain rate past barrier elements, an essential premise is to assess any *change* in incident consequence due to *change* in criteria. Any change in the leak rate through the remaining barrier component should not affect the immediate consequences from an initial incident, nor should it lead to change in consequence in the state of well control constrained by the remaining barrier after the effects of an initial incident has passed. The consequence from any initial incidents should already be covered in the installation risk assessment, but applying this method will help in bridging the gap between disciplines when it comes to assessing acceptable vs. unacceptable leak rates.

3 METHODOLOGY STEP BY STEP

3.1 Initial scope of work

To begin the work in assessing a new criterion for selected components, the current background data needs to be evaluated and assessed to ensure enough quality in any changed criteria. Involvement from all relevant stakeholders is therefore important so no element is overlooked.

3.1.1 Establish multidisciplinary team

It is vital for the success of a project like this that a multidisciplinary team is established. Project team may include relevant personnel from e.g.:

- Technical Safety
- Risk Management
- Well Integrity
- Asset/operation Integrity
- Production Engineer
- Drilling and well/ interventions
- Offshore Installation Manager
- Operations Representative
- Union Representative

Other resources as appropriate.

3.1.2 Gather asset information

To ensure quality in subsequent assessments it is important to gather information regarding current safety levels on the installation, to be able to use these for comparison when later looking at any changes in the leak rates. Limits for unacceptable environmental release, topside ESD/PSD acceptance criteria etc. should be collected and used as reference when doing adjustments to the proposed leak criteria for the valves. Information about well types reservoirs, process system etc. Should also be gathered for easy reference at later stages if needed.

3.1.3 Fluid composition and reservoir conditions

Reservoir conditions, reservoir qualities and the actual fluid composition of the medium that would be leaking, needs mapping for later reference as this will impact any consequence of a leak at a certain rate. This should include current reservoir pressures, SIWHP, pressure buildups, future assessments of reservoir pressure etc. Not including application specific information would be misleading, as there is e.g. a clear difference in topside consequence for a leak at a certain rate of gas/oil vs. fluids with high water content, or that depleted reservoirs carry a different risk profile then HPHT reservoirs. So this information should be included and accounted for in the assessment.

3.1.4 Establish new criteria range

Some new proposed criteria should be established, which will then subsequently be used in further assessment. These new proposed criteria should have some relation to current acceptable criteria, to anchor the new values to some current known values. Either as multiples of the API-criteria, and also referencing other criteria obtained in step 2. (e.g. 0, 15, 30, 60, 120 scf/min or 0.1, 0.4, 1, 4, 10 l/min etc).

3.1.5 Leak Scenarios

It will be important to understand the leak paths from the source to external environment or connected systems. This can be done by creating drawings to visualize the well and the various well barrier elements, or by the use of fault tree modelling illustrating the different leak paths. A multidisciplinary team consists of personnel with different knowledge and in the early phase of the project all the team members should, as appropriate, be “educated” in well design and well barriers. Identifying external and internal leak paths from a well will ensure that the team members have a common understanding of the agreed project scope.

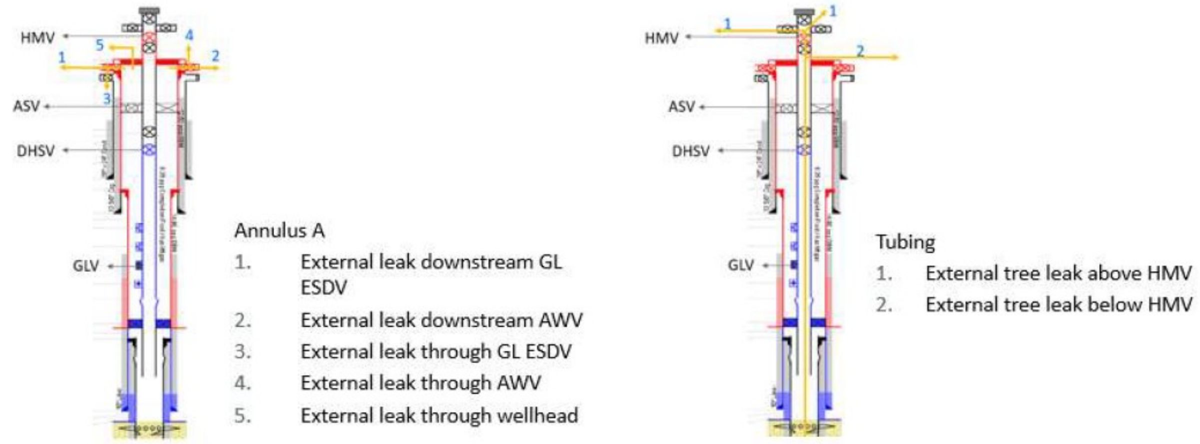

Figure 1 – External leak scenarios from annulus A and tubing

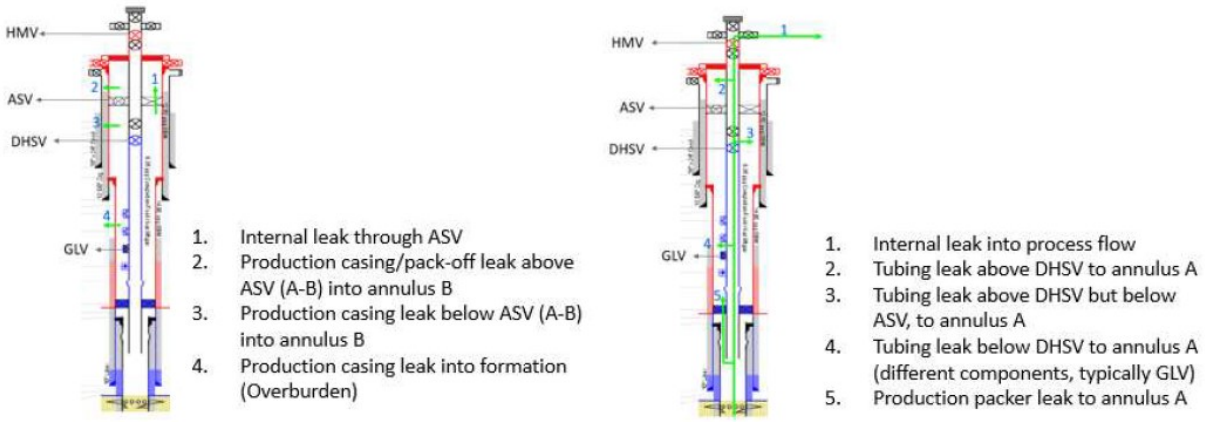

Figure 2 – Internal leak scenarios from annulus A and tubing

Depending on where e.g. an external leak occurs on the well, the volume released and the number of barriers to limit energy supply will change.

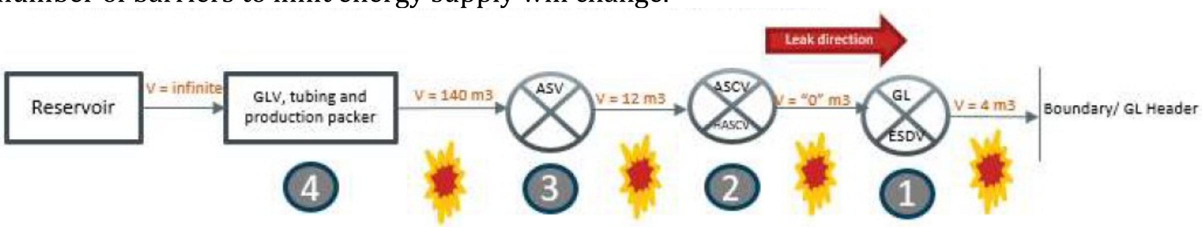

Figure 3 – E.g external leaks and volume between different segments on the annulus side (well barriers)

Based on the drawings created the team should define which well barrier valves that will be part of the work scope and which internal leak acceptance criteria that will be evaluated

3.1.6 Uncertainty evaluations

The Petroleum Safety Authorities Norway (PSA) defines risk as the consequences of the activities, with associated uncertainty.

Uncertainty means lack of knowledge. Throughout the project it is important to have attention to the unknown. One approach could be to use methodology from Flage and Aven* when performing uncertainty evaluations:

Guideline for evaluation of strength of knowledge
HIGH strength of knowledge – all the following conditions are met: • The phenomena involved are well understood; the models used are known to give predictions with the required accuracy • The assumptions made are seen as very reasonable • Much reliable data is available • There is broad agreement among experts
MEDIUM – Conditions between those used to define "high" and "low"
LOW strength of knowledge – one or several of the following conditions are met: • The phenomena involved are not well understood; models are non-existent or known/believed to give poor predictions • The assumptions made represent significant simplifications • Data are not available, or unreliable • There is lack of agreement/consensus among experts

Figure - 4 Strength of knowledge

The following sensitivity guideline is used to evaluate the parameters effect on the result:

Guideline for evaluation of sensitivity
HIGH: Relatively small changes in base case value may change conclusion
MEDIUM: Relatively large changes in base case values is necessary to change conclusion
LOW: Unrealistically large changes in base case values is necessary in order to change conclusion

Figure – 5 Sensitivity evaluations

Uncertainty evaluations should be performed for all parameters used in the internal leak acceptance criteria evaluations.

3.2 Assessment of affected factors

The following chapter contains the various elements that needs to be assessed for change in consequence, with the proposed change in acceptance criteria.

3.2.1 Change in consequence of initial release – Leak rate simulations

The PSA reporting requirements for incidents with external hydrocarbon loss of containment without personal injury or asset damage is > 0.1 kg/s. It is therefore reasonable to evaluate if the new defined internal leak rates (e.g. 0, 15, 30, 60, 120 scf/min etc.) will prolong the initial hydrocarbon release > 0.1 kg/s over a time period that is not considered acceptable. This is most likely only relevant to perform for applications which contain a large HC volume directly behind the barrier bordering to the environment. The large initial release of these volumes is "accepted" from a topside perspective initially, but with a change in leak rate of the remaining barrier, this total release volume will be increased, which might affect the topside risk elements in a negative way (escape routes, main safety functions, FAR values etc.). The various leak points from the XT/WH should be defined and looked at with regards to the duration of the initial leak (e.g. 5 7/8", 2", 1", ½", ¼" etc.). Hole sizes could typically be outlets from the well or hoses connected to the well. Smaller hole sizes could be test ports connected to the well. Once leak points and initial duration of any well release is established, any prolonged effect of the initial release by the change of acceptance criteria of the remaining barrier must be accounted for. It is important to look at different hole sizes and the time it takes to bleed down initial event to evaluate risk for personnel e.g escape route availability.

3.2.2 Asset integrity – Flowline breach

The number of wells connected to a production manifold should also be included in the assessment, as any flowline breach downstream the wells will potentially be "fed" by the sum of leak past barrier elements into the breached flow line. This total release should not exceed any unacceptable continuous topside rate as this will be a potentially prolonged leak at that rate.

3.2.3 Change in Fire /explosions evaluations – Escalation

Heat loads from the new proposed internal leak rates (e.g. 0, 15, 30, 60, 120 scf/min etc.) should be evaluated. Fire/explosions evaluation is an important parameter for platform wells. A fire originating from a leaking well could affect various equipment in the wellhead area e.g neighboring wells, process equipment, installation structure etc. The potential effect on this from the initial leak should be assessed in step 1 but it also needs to be assessed once the initial release has passed. Neighboring equipment should not be negatively affected by exposure of heat loads from an ignited leak from the affected well. Well and process equipment is typically fire tested according to API 6FA/B/C and heat loads should not exceed these requirements.

API 6FA states the following in chapter 1 "Scope":

"The purpose of this standard is to establish the requirements for testing and evaluating the pressure-containing performance of API 6A and API 6D valves when exposed to fire. The performance requirements of this standard establish qualification criteria for all sizes and pressure ratings. This standard establishes acceptable levels for leakage through the test valve and external leakage after exposure to a fire for a 30-minute time period. The fire exposure test period has been established on the basis that it represents the maximum time required to extinguish most fires. Fires of greater duration are considered to be of a major magnitude, with consequences greater than those anticipated in this test."

3.2.4 Gas dispersion and ignition risk evaluations

Gas dispersion simulations should be performed to understand gas plume propagation and the ignitable area of the gas plume for the defined internal leak rates.

Gas plume should not:

- Engulf the entire installation
- Extend into escape ways outside the relevant module
- Prevent possibility of helicopter landing

Input data for gas dispersion simulations:

- Pressure
- Temperature
- Density/composition of gas
- Wind
- Physical restrictions
- Ventilation in area

The explosion risk with associated pressure loads and narcotic effect of gas for the defined internal leak rates should be evaluated.

3.2.5 Escalation potential – Internal

Any continued degradation of the barrier element with a changed criterion should be assessed. The change in criteria should not lead to a higher risk of e.g erosion or mechanical wear due to the increased accepted rate past the component. Any changed rate should be sufficiently conservative to ensure that the new rate is in fact the rate that will be present also after a period of time while work for securing the well is underway. This is an essential premise to qualify a component to a certain rate. If this rate changes over time due to exposure of maximum differential pressure over time, it cannot be considered a qualified barrier.

3.2.6 Search and Rescue (SAR) phase

Conditions for search and rescue may be important, hence an evaluation for the defined internal leak rates should be performed. These evaluations could typically be qualitative.

3.2.7 Normalization/Well control phase

The effect of the defined internal leak rates for normalization / well control phase should be evaluated. There should not be any difference in the normalization work based on the change in leak criteria. Here the access to the well should be part of the evaluation (platform vs. subsea), and whether or not any ongoing leak with a changed rate will cause any more difficulties for normalization operations than a well leaking with the current criteria.

3.2.8 Environmental impact

The change in criteria might change the influence the environmental impact. Any change in the acceptance criteria should not lead to any change in the subsequent environmental impact based on a continued leak after initial release.

3.2.9 Installation risk – Other

Will any of the other main safety functions on the installation be affected by the change in rate? These are typically any other topside factors reflected in the QRA that are not included in the previous steps.

3.2.10 Reputation

With change in criteria a divergence from recognized standards is performed. The assessment should be thorough enough to ensure no reputational damage due to poor assessments or erroneous choices.

3.3 Heat Map Matrix

To understand the effect of the defined internal leak rates, the consequences of loss of containment from a well have been evaluated for point 1 to 10 above. To summarize the evaluations a heat map matrix could be used, one column for each internal leak rate and one line for each of the points 1 to 10. These evaluations should be risk assessed, color coded and plotted into the heat map matrix. The color-coding used will be a reflection of the individual operator risk system, where green is "acceptable", and yellow indicates a change in consequence for that particular parameter.

Heat Map Matrix – Well Barrier Internal Leak Rate					
Consequence with leak rate	0 scf/min or 0 l/min	15 scf/min or 0,4 l/min	30 scf/min or 1 l/min	60 scf/min or 4 l/min	120 scf/min or 10 l/min
Change in initial release					
Asset integrity flowline breach					
Fire & Explosion - Escalation					
Gas dispersion and ignition risk					
Escalation potential - Internal					
Search & Rescue					
Normalization / Well Control					
Environmental impact					
Other installation risk					
Reputation					

Table 1: Example of heat map matrix representation of various assessment elements

Based on the resulting heat map matrix it should be easy to identify the limiting evaluation parameter(s) (e.g. gas dispersion and ignition risk for a topside well) and the increasing risk for the corresponding internal leak rate is also easily displayed.

For all practical purposes an internal leak rate should not be zero, hence any defined internal leak rate has an associated risk. As the internal leak rate increases the associated risk increases. It is the individual operating company that will decide the maximum allowable internal leak rate through a well barrier element. NORSOK D-010 is today referring to API RP 14 B with regards to internal leak rate through well barriers (e.g DHSV), hence this is commonly used as internal leak rate acceptance criteria in the industry today. Therefore, the baseline in the heat map matrix would be the application of the API criteria. Since the same criteria are today used for both platform wells and subsea wells, the heat map matrix illustrates that not all factors will be relevant for a subsea well. By looking at the heat map matrix it could be argued that fire, gas leak duration, dispersion and ignition risk and search & rescue is less critical for a subsea well versus a platform well.

3.4 Conclude, Document & Implement

Based on the heat map matrix a new internal leak rate criterion could be set. This criterion could be permanent or temporary (deviation). Prior to finally conclude it could be useful to ask some controlling questions:

- Is it feasible to test new criterion?
- Is there any limit for how many wells new criterion can be utilized?
- What is the total acceptable rate into the production system or to the wellhead area.
- Any degradational factors related to new criterion such as corrosion, erosion, mechanical wear etc. that has not been accounted for?
- Could new criterion cause escalation to other equipment/utility systems/modules which is exposed to loads which they are not qualified/tested for e.g. API 6FA/B/C fire requirements?

The project work and evaluations should be documented in a report which is stored for future reference. Change should be documented in a MoC, which is signed by relevant stakeholders prior to implementation and reference be made to the new criteria in the plant specific performance standard for the component(s) with altered criteria.