

Guidelines for produced water injection

Report No. 2.80/302
January 2000



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Disposal of produced water by injection guidelines

Report No: 2.80/302

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These guidelines have been prepared for the OGP by the Environmental Quality Committee (EQC) working on the basis of a draft guideline prepared by an SPE Task Group.

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1 Introduction

Production of oil and gas is usually accompanied by the production of water. This produced water consists of formation water (the water present naturally in the reservoir), or flood water previously injected in to the formation. As exploited reservoirs mature, the quantity of water produced increases. Produced water is the largest single fluid stream in exploration and production operations. Consequently, the management of produced water requires a structured and integral approach and will consider a broad range of technologies and strategies, one of which is disposal. In turn, there are a number of options for disposal including direct discharge and injection.

A key aspect of produced water disposal is the management of its fate and effects in the receiving environment. Clearly, industry's produced water management practices should be of a standard that meets the requirements of the regulations to which it may be subjected. The determination and implementation of the most appropriate option in a particular situation will depend on applicable regulatory requirements, the environmental protectiveness of the various options and associated costs.

The OGP has published a number of reports relating to management of produced water. These reports are useful adjuncts to the considerations in this report and include:

“North Sea Produced Water: Fate and Effects in the Marine Environment”, report No 2.62/204, May 1994

“Produced Water Treatment: Current and Emerging Technologies”, report No 2.64/211, July 1994

“Technologies for Handling Produced Water in the Offshore Environment”, report No 2.71/247, September 1996

Onshore or in sensitive nearshore environments, injection is frequently the selected disposal option. Offshore, treatment to remove oil, followed by discharge to the sea is most common. When injection is chosen, confine-

ment of the injected produced water within the target strata is central to the environmental acceptability of the disposal process.

Since injection, either by matrix or fracture injection, is more operationally complex than other disposal options, a range of circumstances can occur that will interrupt injection. As for any waste management option, it is good practice to identify, as part of the planning process, acceptable alternative management methods to be used on a contingency basis. In areas where injection has been selected as the primary option, for operational, environmental or regulatory reasons, contingency options may in certain instances include, but are not limited to:

- use of alternative, or stand-by injection wells
- discharge to the sea, in compliance with relevant regulations
- discharge to the land surface, in compliance with relevant regulations
- discharge to fresh water bodies, in compliance with relevant regulations
- storage (lined impoundments or tankage)
- diversion to treatment systems (where applicable or feasible)
- well shut-in

In every case, the development of sound contingency plans that meet regulatory requirements is necessary and should be done in parallel with the development of the primary injection plans.

One management option for produced water is injection for the purpose of waterflooding, whereby produced water is injected into oil-bearing layers or pressure supporting aquifers of the reservoir to provide pressure support and sweep oil out of the pore space and into the production wells. *This practice does not constitute disposal and will not be further addressed in this guideline.*

For the purpose of this guideline the following key terms are defined:

Confinement

The process by which injected produced water is kept within specified horizons.

Confinement zone

The two layers immediately surrounding the containment layers and the geologic strata between them. The confinement zone comprises rock layers into which fracture propagation and migration of injectate is not allowed. Hence the purpose of the confinement layers is to prevent the migration of produced water or fractures outside the area they confine.

Containment layers

Rock layers just above or below the injection horizon that are not directly accessible from the well bore. The injected water may be allowed to enter, but not escape the containment layers.

Containment zone

A geological formation, group of formations, or part of a formation that is capable of limiting fluid movement above or below the injection zone. Fluid may enter the zone but will not move outside it.

Potable water aquifer

A geological formation or group of formations, or part of a formation that is capable of yielding a significant amount of potable water to surface.

Fracture propagation pressure

The fluid pressure which will cause an existing fracture to start extending in any direction.

Fracture closure pressure

The fluid pressure at which an existing fracture is no longer deemed open mechanically (at which the fracture surfaces touch).

Overburden stress

The stress that reflects the total weight of the overlying rock and fluid, if present, from the surface of the sea or land down to the depth at which the stress is defined.

Horizontal stress

The stress representing the horizontal forces within the porous saturated rock.

Fracture azimuth

The main direction of any hydraulically induced fracture. This direction is generally perpendicular to the direction of the minimum horizontal stress acting at the fracture depth.

Vertical conformance

The characteristic of the flow into the vertical cross section of the rock column in which injection is taking place and the extent to which such characteristic is consistent with the desired outcome of the injection process. Good conformance implies fluid flow rates into various layers are in agreement with injection plans.

Injectivity

The injection rate divided by the difference between the injection pressure and the reservoir pressure. A measure of the ability of the well and injection interval to take up injected fluids

2 Produced water injection data

This section identifies the data relevant to the selection and design of a produced water injection operation.

2.1 General information

- location of installation (onshore/offshore)
- if offshore, water depth
- proximity to other hydrocarbon producing wells or fields, potable, irrigation or industrial water producing wells .
- proximity to other disposal wells
- proximity to areas of particular environmental sensitivity

2.2 Applicable regulations, codes and standards

- regulatory bodies to be consulted
- regulatory restrictions and constraints
- internal company and industry guidelines

2.3 History and current status

- target injection formation discovery date
- injection formation drilling, circulation and fluid loss, and data acquisition histories
- future operating plans
- previous injection into or production from the target formation
- company and/or industry experience with similar injection sites

2.4 Specific information

- produced water volume and rate
- geology
- hydrology
- geochemistry of injected produced water and its compatibility with connate and/or other water(s) within the injection horizon
- injection and confinement zone geohydrological properties
- injection and confinement zone geomechanical properties
- in-situ stress profile in the various layers
- location, age, depth, and condition of nearby water, oil and gas, injection, or other wells, whether active, inactive or abandoned
- location, orientation and properties of nearby faults or fractures.
- if existing well is to be converted for injection :
 - well age
 - construction details (dimensions and location of casing, cement, perfs, *etc*)
 - well history (*eg* pressure data, logs, squeezes, work-overs, *etc*)

3 Produced water quality in relation to injectivity & operations

3.1 Geochemical and physical properties of injected produced water and its compatibility with connate waters

The following data are used to define/predict the potential for scale formation and to assess the potential permeability degradation that may result from an incompatibility among the injected produced water, connate water and injection/confinement zone lithology (*eg* adverse rock/fluid interactions). Such permeability degradation can plug the formation around the injection well and reduce the effectiveness of injection operations.

- compatibility of the injected produced water and injection horizon formation fluids
- compatibility of the injected produced water with the lithology of the injection and confining zones
- heat capacity of injected produced water

The concentration and particle size distribution of dispersed hydrocarbons and suspended solids are important characteristics that bear upon both water treatment and injectivity. In addition, produced water contains a wide range of dissolved and suspended materials that may affect injectivity. These substances include:

- major cations (Na^+ , K^+ , NH_4^+ , Ca^{2+} , Mg^{2+} , Ba^{2+} , Sr^{2+} , Fe^{2+})
- major anions (Cl^- , Br^- , SO_4^{2-} , HCO_3^- , CO_3^{2-} , BO_2^- , NO_3^- , OH^- , PO_4^{3-})
- fatty acids (formic, acetic, propionic, butyric, valeric)
- dissolved gases (CO_2 , H_2S , O_2)
- temperature
- pH
- hydrocarbons (dispersed and dissolved)
- total and oil-free suspended solids

Other produced water properties relevant to injectivity include:

- particle size distribution
- filterability or injectivity (membrane and/or core-flood tests)

In some regulatory frameworks there may also be a requirement for information on other naturally-occurring substances, or production/work-over chemicals. These data may also be important in securing agreement on contingency plans to be invoked if injection fails.

To address issues related to facilities design, collection of any or all of the following data may be relevant depending upon the objectives of the produced water injection programme. Target areas for consideration include treatment process selection, corrosion management and future injection well interventions (*eg* stimulation):

- specific gravity of produced water
- specific gravity of produced hydrocarbon fluids
- total dissolved solids
- water corrosivity
- water conductivity
- rheological properties of separable (from produced water) oil
- microscopic analysis of separable solids
- chemical analysis of separable solids
- water treatability characteristics (*eg* settling, flotation, hydrocyclones, *etc*)

3.2 Produced water treatment

Generally, produced water may be injected with minimal treatment when injected under fracturing conditions or into (thermally) fractured formations. Water quality requirements for sustained matrix rate (sub-fracturing) injection are typically much more stringent than for fracturing injection. If the injected water contains solids large enough to plug the formation (a fraction of the median pore size), injectivity will decline. The rate of loss of injectivity will depend on the surface area of the completion. Unlike in fracturing injection, the surface area exposed in a completion operated at matrix rates does not increase. A cased and perforated completion typically exposes a small amount of formation and may be particularly sensitive to suspended solids. Open hole and proppant-fractured completions are expected to be less sensitive (although by no means insensitive) to suspended solids, provided the solids are not large enough to plug completion components (*eg* sand screens or proppant).

Downhole solids contributing to plugging may include not only the solids escaping filtration, but solids generated after water treatment (*eg* corrosion, scale, and

bacterial products). Consequently, stringent corrosion inhibition, scale inhibition and bacterial control, as well as filtration, may be required for matrix rate injection.

The content of suspended oil in the injected water may also impair a sub-fracturing injector. After suspended solids have formed a filter cake on the exposed formation, even a small amount of oil can reduce the permeability of this filter cake to water. Larger quantities of suspended oil may impair injectivity by reducing the permeability of the formation to water, especially in injection zones that initially have less than the mobile oil saturation. Typical oil separation techniques can be used to reduce suspended oil to acceptable levels.

A determination of the degree and type of treatment required to maintain injectivity is typically based on an analysis of all available produced water characterization and injection formation data, including water quality data, core data, and well test results. The costs of treatment and well workovers for matrix injection should be weighed against the higher capital costs but lower operating costs for injection under fracturing conditions.

4 Well design and construction

The design and construction of an injection well are key factors in achieving the produced water injection objective. The well design and construction account for operating conditions (pressure, fluid composition, duration, *etc*) and address identified potential well failure scenarios.

4.1 Design conditions

The packer, tubing and wellhead design can be checked against the loads anticipated during injection, including later in the well's life when corrosion and erosion may have degraded the well's integrity. These loads can be established and defined by considering:

- maximum anticipated injection pressures
- maximum injection rates
- injection fluid temperature
- composition and properties of the injection fluid
- injection volumes

4.2 Tubing axial loading, burst and collapse

Once the design loads have been defined, they can be checked against the tubular ratings to ensure that adequate safety factors are maintained. Load cases to be considered would include:

- tubular axial loading (compressive and tensile), burst and collapse, incorporating rating reduction due to:
 - drilling wear;
 - erosional wear;
 - corrosion by injection fluid or static annular fluids;
 - biaxial and triaxial considerations of collapse reduction due to tension and compression.
- effects of expansion and contraction of the tubing due to thermal cycling involving connection efficiency and connection seal efficiency.

4.3 Wellheads

Wellhead design will typically take account of projected:

- pressure
- corrosion due to injected and external fluids
- erosion
- temperature
- sealing integrity under thermal cycling
- seal compatibility with injected fluids

The wellhead valve configuration, control and operation should consider the erosion and corrosion effects of the injected fluid.

4.4 Well completion

The life cycle performance of an injection well can be affected by its completion in the injection zone. Selection of a completion configuration depends on the reservoir properties, quality and quantity of fluid injected and planned injection operations (continuous, intermittent, backflow, *etc*). Potential completion options include openhole or cased and perforated. Also, sand control may be required, ranging from a slotted liner to screens and gravel pack.

An openhole completion requires the least hardware and offers the lowest sandface pressure drop. However,

it can make subsequent workover treatment difficult. A cased and perforated completion offers flexibility and control over the injection zone. However, a cased and perforated completion exposes only a small formation surface area and can be expected to be prone to plugging if operated at sub-fracturing pressures. Sand control may be required if the injection zone is unconsolidated. Installing sand control helps ensure that the zone does not collapse into the wellbore or casing upon shut-in or backflow conditions.

4.5 Isolation of injected water at the well

Once the produced water has been injected into the well, it will be contained by both mechanical and geological barriers. The mechanical integrity is derived from:

- packer, tubular and wellhead design
- wellhead isolation valves
- cemented annuli

Each string of casing or tubing, along with the cement that seals its annulus against produced water injectate, represents a layer of protection that confines the injected fluid to its design pathway direct to the injection zone. Correspondingly, each continuous cement-filled annulus provides an additional protective layer. For example, the following can be considered layers of protection:

- surface casing cemented to surface (two layers of protection); where potable water aquifers are present, these would extend through the potable water zone
- each casing string and cement (having at least one string cemented to and across the disposal formation)
- tubing and packer (also allows tubing/casing annulus pressure monitoring)
- corrosion-inhibiting fluid in tubing/casing annulus

Redundant layers of protection provide improved isolation certainty, as, in that case, failure of one layer (due to cement channel or corrosion, for example), will not directly lead to loss of containment at the well.

Considerations in cementing design and implementation include:

- appropriate design of the compressive strength of the cement
- determining the theoretical and actual length of the cemented interval, including the height of the cement column
- casing shoe strength testing
- confirming the cement bond between casing and formation

The various techniques to confirm the cement bond between casing and formation have differing applicabilities and limitations, whether in interpretation or detection capacity, and include the following:

- cementing records (cement volume based on caliper log)
- cement bond or evaluation logs
- radioactive tracer survey
- temperature survey
- oxygen activation log

Where an existing producing well is to be converted to injection for disposal, casing and cement may not be designed to provide isolation of injected fluids. Modification of the well should be considered in such cases to provide the desired degree of isolation.

5 Containment and confinement

The aim of a produced water injection operation is to ensure the containment and confinement of the injected water within acceptable injection zones away from any underground source of usable water for drinking or irrigation. The need for reliable prediction of the fate of the injected water is tied closely to this objective. The conditions under which the confinement of the injected produced water and any consequent fractures are achieved should be understood. Figure 1 (opposite) illustrates the subsurface containment and confinement geology as defined in the Introduction to this document.

The sections below will address the concept of an area of review as an aspect of ensuring confinement, and present considerations for containment and confinement of fractures in a fracture injection programme.

5.1 Area of review

The area of review can be defined as an area that is assessed for the presence of possible conduits for injectate flow outside the confinement zone. Possible conduits could include active, inactive or plugged bores or transmissive faults or fractures that penetrate the confinement and injection zones. In some regulatory frameworks and, in particular where there may be adjacent water resources that need to be protected, the area of review may be defined in terms of an allowable radius of influence around the injection site. The size of the area of review can be based on calculations of the radius of injection pressure head build-up sufficient to move fluids above the confinement zone. This area is an appropriate area for which to establish a performance specification that constrains the movement of injected fluid into underground reservoirs of potable or irrigation water or up to the surface.

During the operational injection phase, the area of review is one within which the elevation of the initial piezometric surface (fluid level) for the formation fluid in the injection zone is predicted to rise such that it equals the piezometric surface of any potential overlying usable aquifer, plus an adequate pressure increment sufficient to move the injected produced water into the lowermost overlying usable aquifer.

5.2 Reservoir flow and fracture propagation prediction

Predictive modeling of produced water injection will include both flow (reservoir) simulation and injection well fracturing and fracture propagation. These will establish the fate of the injected produced water and provide the operator with an integrated knowledge suf-

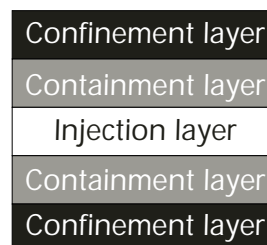


Figure 1: Schematic of geological structure of an injection zone

Some of the factors that will assist in the definition of the area of review include:

- regional and local geology
- regional stratigraphy
- regional structure
- seismic history
- injection, containment and confinement zone properties
- hydrology of underground sources of potable and/or irrigation water, if present
- geo-hydrological conditions
- flow properties of the injection layer
- determination of the vertical hydraulic gradient.

ficient to manage the injection process in an environmentally protective manner.

The modeling should provide predictions during the operational injection period and an assessment of the residual pressure fields after shut-in of the injection well.

The latter may be important if the injection process leaves the formation with higher pore pressure than that which existed before the start of produced water injection. Modeling studies will also take account of the uncertainties associated with such prediction and the understanding of the nature of the sub-surface horizons being studied.

5.2.1 Flow (reservoir) simulation

This activity is conducted to predict to the overall areal and vertical extent of the reach of the injected water on a field scale. The process closely resembles the reservoir engineering simulation efforts routinely conducted by operators. In reservoir simulation the details of the near well-bore region are not as critical as the overall impact of the injected water volume on recovered hydrocarbons. However, correct prediction of vertical conformance of the injection profile and how much water is injected into each reservoir layer are important for management of injection operations.

5.2.2 Fracture propagation

The definition and prediction of the orientation and extent of fractures should ensure that both the injected produced water and the fractures remain in the containment zone. There are fracture propagation simulators specifically aimed at predicting the vertical and areal extent of the fracture as well as its geometry.

5.2.3 Injection and confinement zone geohydrological properties

Information on the following will be used to verify and calibrate the properties and pressure profile of the effective injection zone, containment strata, confinement zone and overlying formation(s):

- horizontal and vertical gas and liquid permeability and porosity of the injection, containment and confinement zones
- relative permeability curves to oil, water and gas
- connate water and (if applicable) residual oil saturation values
- injection and containment zone temperatures
- in the case of existing wells, well testing and drill stem tests including:
 - injection/fall-off tests
 - step-rate injection/fall-off tests
 - inter-well pulse testing.

This information may also be needed as input for flow simulation of the injected produced water.

Once the well is in operation, spinner surveys can be done to provide verifying information on the rates of produced water entering the injection layers.

5.2.4 Injection and confinement zone geomechanical properties

This information will be required to establish the input parameters for reservoir and fracture simulators and to assist in the determination of fracture geometry. It includes:

- presence and characteristics of natural formation fractures
- laboratory-determined properties:
 - compressive strength and fracture toughness
 - elastic moduli (Young's modulus and Poisson's ratio)
 - heat capacity of rock in injection and containment zones
 - poro- and thermo-elastic constants

5.2.5 In situ stress profile in the various layers

The definition of the state of stress in the injection region is needed to determine vertical fracture extent and height confinement. It will also define the direction of water breakthrough to nearby wells and the most likely direction of the areal hydraulic gradient. Techniques such as micro-fracturing, step-rate tests, hole break-out and stress profile data developed from geophysical logs may be utilised. Regional stress trends may also prove to be adequate for the definition of the stress regime in the injection site. The information will include:

- magnitude and azimuth of the minimum horizontal in situ stress (fracture gradient)
- overburden stress magnitude
- sedimentation history (overburden uplift)

6 Process monitoring and control

The extent to which regulatory authorities in different countries require monitoring and verification of control varies considerably. In any case, the operator should establish a monitoring programme designed to ensure that the injection process is proceeding as planned.

Based on the objectives of the injection project (*ie* to contain the injected fluid in the target formation), the

operator can define the range of conformance and failure scenarios. In conjunction with the engineering of the injection process, a suitable monitoring and testing programme can be designed. The programme should be able to identify failures in the injection process and form the basis of a data set for promulgation of the lessons learned from the operation.

6.1 Continuous pressure monitoring

A comparison between modelled and actual injection pressure is initially required for model validation and to set up an acceptable pressure monitoring programme. A very useful data representation is the Hall plot (Figure [2]) that shows pressure multiplied by duration of injection versus the injected volume. A straight

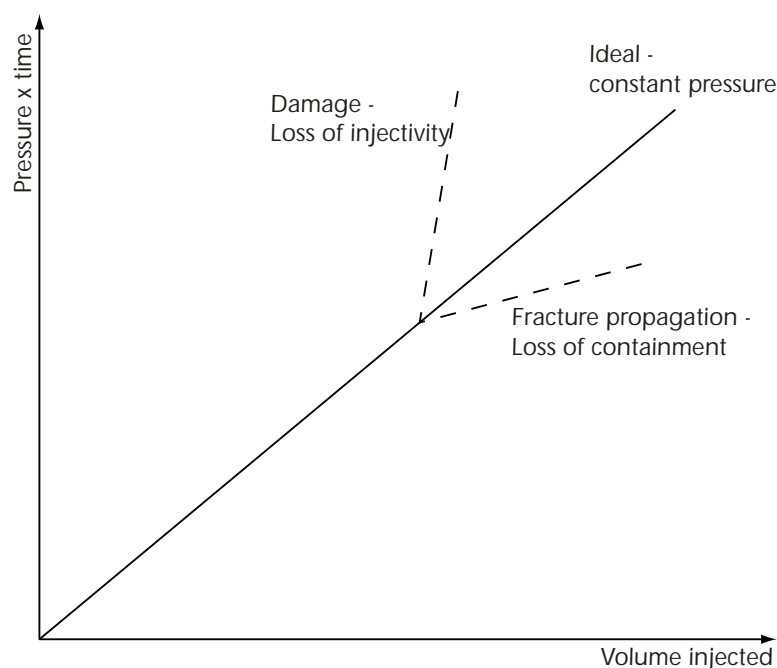
line is expected for constant injectivity and a curving upwards indicates loss of transmissivity which usually occurs over the lifetime of the project. Unwanted fracture propagation can be seen when the plot levels off.

Initial engineering studies will give the necessary surface pressures for reliable operations, whether dictated

by tubular/wellhead limitations or fracture pressures. From the initial studies a monitoring programme may be set up to include:

- initial shut-in wellhead pressure
- wellhead injection pressure versus pump rate
- pressure fall-off over shut-in periods
- annuli pressures of injectors and neighbouring wells

Figure 2: Hall plot



6.2 Injectivity and fall-off testing

Field measurements provide data for the modelling of the fluid front movement and for establishing an appropriate injection pressure. Care should be taken to interpret the test results, since an appropriate operation pressure may deviate from the initial fracture propagation pressure. Disposal of relatively warm fluid into a shallow injection horizon will increase the pressure required to propagate a fracture over that initially required. The reverse will happen upon injection of relatively cool fluid. The objectives of injectivity and fall-off tests are to:

- measure reservoir pressure, fracture propagation pressure, closure pressure
- determine the development of formation transmissivity (*ie* horizontal permeability and fracture dimensions)
- confirm the size of the flow unit into which injection takes place

A more detailed description of injectivity and fall off testing is given in Appendix 1.

6.3 Observation wells

If observation wells are available, passive acoustic (micro-seismic) monitoring and downhole tiltmeters may yield information about fracture growth. Pressure and fluid samples may give information about fluid flows.

6.4 Injection fluid

As explained in the section on water quality (see section 2), the quality of the injection fluid is important for maintaining injectivity. A regular description of fluid composition should provide valuable information in the event that decline of injectivity is observed. Routinely monitored injection fluid properties may include:

- temperature
- pH
- solids Content
- dispersed and dissolved hydrocarbon content
- salinity

It is advisable to monitor any changes in produced hydrocarbon fluids processing conditions which may affect the produced water quality, treatment and injectivity. Such changes should be identified and their impact assessed.

6.5 Mechanical components

Monitoring the mechanical integrity of the injection well or annulus is integral to proper operation of produced water injection. Methods applicable to the evaluation of mechanical integrity (*ie* absence of leaks in tubing, casing, or packer and absence of flow behind casing) include the following:

- annulus pressure monitoring
- pressure testing
- temperature logging
- noise logging
- pipe analysis survey
- electromagnetic thickness survey
- caliper logging
- borehole televising
- flowmeter survey
- radioactive tracer survey
- oxygen activation logging
- cement bond logging

As a routine matter, monitoring the injection pressure and rate, and the tubing by production casing annulus pressure, can provide indicators of the status of the mechanical integrity of the injection well without interrupting injection operations. The wellhead and casing and tubing can also be monitored for signs of erosion or corrosion, but this may require suspending injection operations while a survey is run.

If a leak is suspected, shutting in the injection and performing a simple pressure integrity test on the annulus may confirm the problem. Then running the logs and surveys listed above may be considered. Of these techniques, the noise and temperature logs and radioactive tracer survey have the capability to detect leaks in tubing, casing, or packer as well as fluid movement behind casing.

7 Operational issues

Contingency planning is an integral part of preparing a produced water injection operation. Potential failure modes should be evaluated at the planning stage along with the necessary remedial actions that might be taken. The following sections set out some examples of potential failures.

7.1 Pressure build-up

There are two distinct cases: a rapid and sudden pressure build-up or a slowly increasing injection pressure as a result of decreasing injectivity. Pressure can be monitored to ensure it does not exceed the maximum allowable injection pressure.

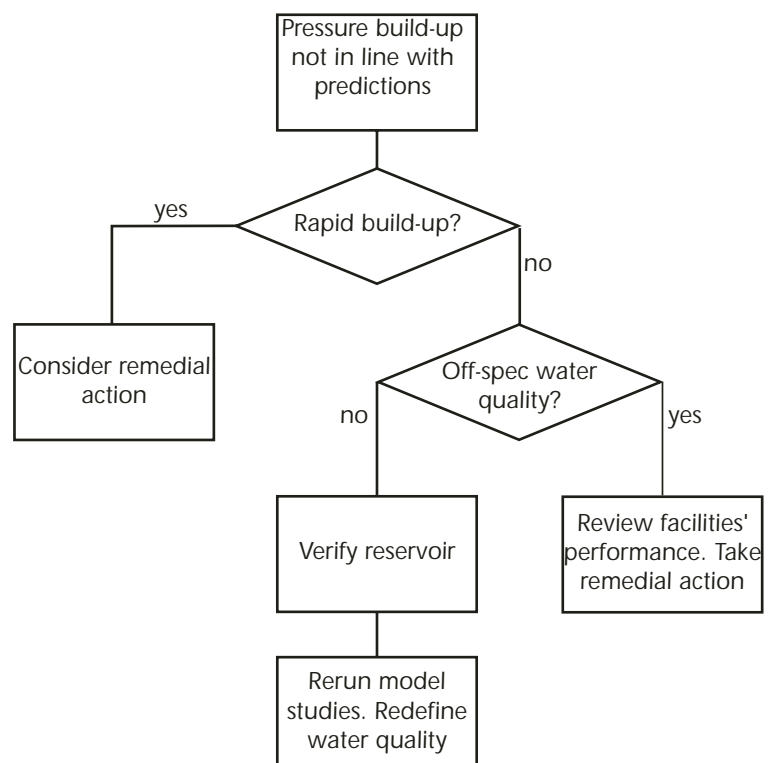
A rapid pressure build-up will generally be the result of blockage of the inflow area caused by either water containing a lot of unexpected and unwanted materials (*eg* solids, emulsions) or by an unexpected injection/formation water compatibility problem. Loss of injectivity during produced water injection due to plugging has been shown in some fields to be reversible, *ie* an improvement in injection water quality leads to a direct improvement in injection well performance. This implies that, in some cases, waterflood/disposal performance can be improved by upgrading produced water treatment or by cycling wells between produced water injection and injection of another type of available (and compatible) water without having to resort to workovers. In the event this approach proves unsuccessful (*eg* in the event of scaling-induced loss of injectivity) or not feasible (*eg* no alternative source of injection water available), the cause of the plugging problem has to be determined and remedied to continue use of the well. Then the well's injectivity can be restored by back flowing, conventional stimulation (matrix treatment) or through hydraulic fracturing. A slow pres-

sure build-up which is not in line with (predictive) model studies, is either caused by different reservoir characteristics than assumed (and hence possible incorrectly set) water quality specifications or by off-specification water quality. In the former case, reservoir characteristics can be verified and if found to be deviating from the original assumptions, model studies rerun and water quality specifications redefined. In the latter case, surface facilities' performance will need to be reviewed/investigated and remedial actions taken where necessary.

In the event of unsuccessful prevention or remediation of the pressure build-up, injection can be continued as long as the agreed maximum injection pressure is not overstepped. In some cases, such a situation becomes progressively more difficult to remedy and the well has to be (prematurely) abandoned.

The following flow chart (Figure 3) summarises the actions to be taken in the event of unexpected pressure build-up:

Figure 3

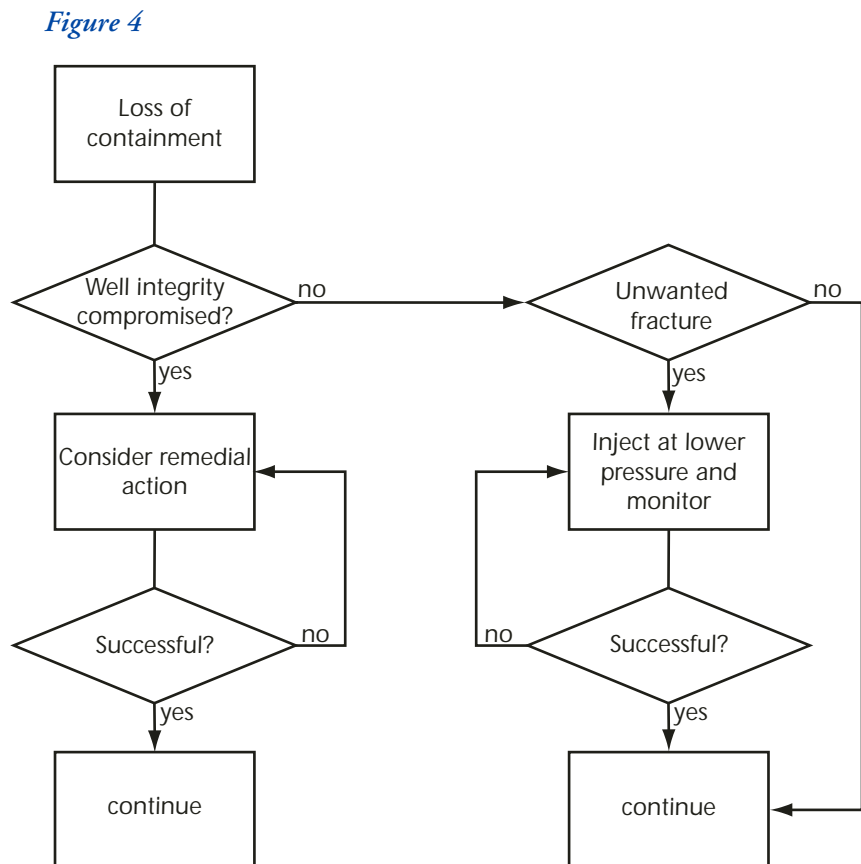


7.2 Confinement problems

For injection programmes where injection by fracturing has been analysed and confinement of the fracture zone and injected fluids confirmed, loss of injectivity can be mitigated by increasing injection pressures, thereby allowing initiation and/or propagation of fractures and exposure of clean rock faces. From predictive models, the operator will have gained insight into the degree that vertical conformance can be maintained and fracture growth contained. Notwithstanding, inadvertent (*ie* unplanned) confinement problems may occur. Indications of confinement problems may manifest themselves through pressure perturbations and/or transient effects. Problems which may arise are:

- breach to outer annulus
- breach to inner annulus

A breach of confinement is an indicator to consider remedial action. Possible actions include remedial cementation, closing off the injection horizon and re-perforating on another horizon either through deepening the well or side-tracking it, *etc.* If the well can no longer be used for further produced water injection, remedial alternatives will include abandonment. Figure 4 summarises the actions to be taken in the event of confinement problems:



7.3 Mechanical complications

Due to mechanical (corrosion and/or erosion) failures of the wellhead, packers, tubing or casing, unwanted leakages may result. If either wellhead or casing is damaged and/or not able to contain pressure, repairs can be carried out (workover). If the tubing integrity has been

compromised, either repairs or recompletion of the well may be considered depending on the evaluated consequences of the particular failure and/or the probability of recurrence when injection is resumed.

7.4 Alternative strategies

Under certain circumstances, it may be necessary to suspend injection for extended periods or even to terminate the injection operation. Plans will need to be in place to implement alternative produced water manage-

ment strategies. It is advisable to have any such strategies agreed beforehand with appropriate regulatory agencies so that unnecessary disruptions to production are avoided.

8 Injection well abandonment

Abandonment of a well is a succession of operations to restore the isolation of all permeable levels crossed by an injection well. The isolation will block communication between the reservoir and the surface and ensure there is no cross flow between reservoirs or into usable aquifers. In essence, the procedures for abandonment of a produced water injection well are not significantly different from those employed in abandoning other sorts of wells.

8.1 Plugging Strategies

A well plugging generally makes use of three different types of barriers. These are:

- Liquid plug - a column of liquid from the surface to the top of the reservoir with sufficient density to balance the pressure of the reservoir.
- Mechanical plug - a system (bridge plug, cement retainer, packer) set in a section of the well of known dimensions. This barrier is often consid-

ered temporary and is used to precisely position a cement plug to avoid slippage and potential contamination of the cement plug during curing.

- Cement plug - cement positioned by circulation in an open hole, casing or annulus. Positioning of the cement plug is achieved by pumping for a predetermined duration and cement volume that is calculated individually for each well to be plugged.

8.2 Plugging Implementation

The design of a well abandonment depends on several factors including the number of zones that have to be isolated. Isolation is achieved for each zone by

- positioning a cement plug on top of the zone
- an adequate fluid column above each plug to balance the maximum pore pressure within the zone
- placement of one or more cement plugs (depending on depth) between the upper permeable zone and the surface

The following guidelines may be useful for the design of well plugs:

- The open hole is plugged or perforations squeezed off. In unfavourable open hole cases, (eg high deviation, caving or sloughing), longer plugs may be needed to ensure shear strength of the plug and integrity of cement (freedom from contamination that may occur on both ends of the plug). The plug may be tested by applying weight using the work string.
- The plug placed at the top of an open hole section, at the top of a production liner, or above perforations, is the primary barrier isolating the injection zone. This important plug is typically significantly longer than other plugs in the well, and typically extends a significant length into the casing above the open hole or perforated interval. This plug may be tested by applying weight using the work string and by closing off the annulus and pumping in fluid under pressure. Each cement plug is separated by fluid (mud, brine or water) that may be treated with

corrosion inhibitor that is environmentally safe for this use.

- The cement plug can be placed by circulation or squeeze (injection without returns).
- In order to effect a cement seal from the inside of the wellbore to the formation wall, open annuli between casing strings are perforated and squeezed/circulated with cement. Alternatively, casing can be cut/retrieved and a cement plug can then be placed across the entire wellbore diameter.
- For each well, laboratory tests can be performed to determine cement composition, specific gravity, and pumping time.

At the end of an abandonment operation, it may be useful to document the following:

- the initial abandonment plan
- the abandonment operations conducted in the field, along with changes to plans necessitated by field conditions
- the configuration and lengths of casing and tubing remaining in the well
- the location and length of plugs, including pumping duration and cement volumes as applicable
- test reports for each plug

In order to allow easy intervention during abandonment, if necessary, the well head should not be cut until the stability of each annulus has been determined. Thereafter, the well head can be cut just below the ground or mud line.

9 References

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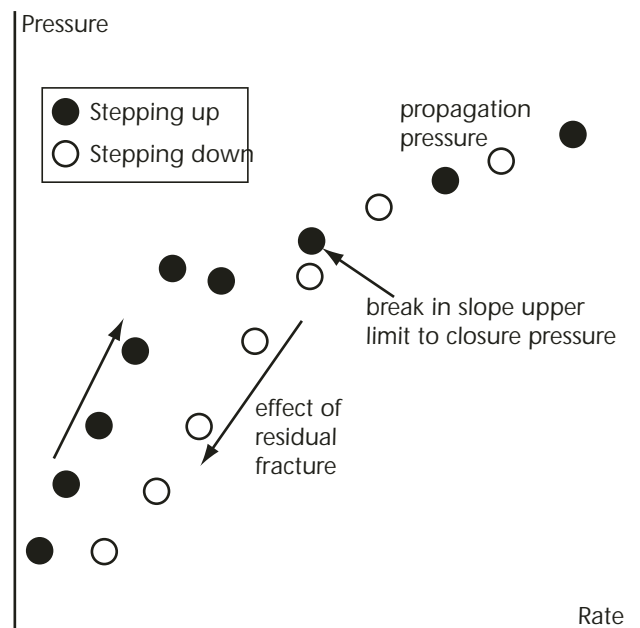
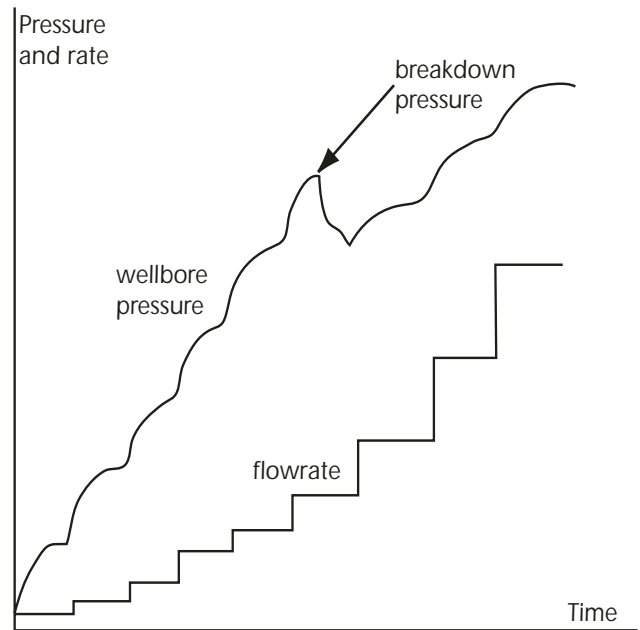
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Appendix 1 - Detailed description of injectivity and fall-off testing

In the following we assume that a pilot well is used for start-up and initial testing. For a new well, an appropriate completion must be selected. In particular, competent perforating procedures are important, paying attention to multiple layers. Care should be taken to ensure that the perforations are open. Sufficient flow rate is needed to clean up the perforations, since perforation debris that is left in the perforation tunnels may form an external filter cake upon injection and seriously hamper the well's injectivity. Also, one should avoid injecting below fracture pressure with water that contains contaminants that could plug the reservoir. Here, it is assumed that the permeability is not extremely high. Very permeable formations will accept any conceivable injection rate and fracture pressure may not be reached early in the project depending on the formation depth. Plugging may still occur and in the course of several years, the pressure may reach the fracture pressure. Also, it will be important to design appropriate procedures for strongly deviated or horizontal wells, where the fracture orientation with respect to the well becomes an issue. For disposal under normal conditions, the following test procedure may be followed:

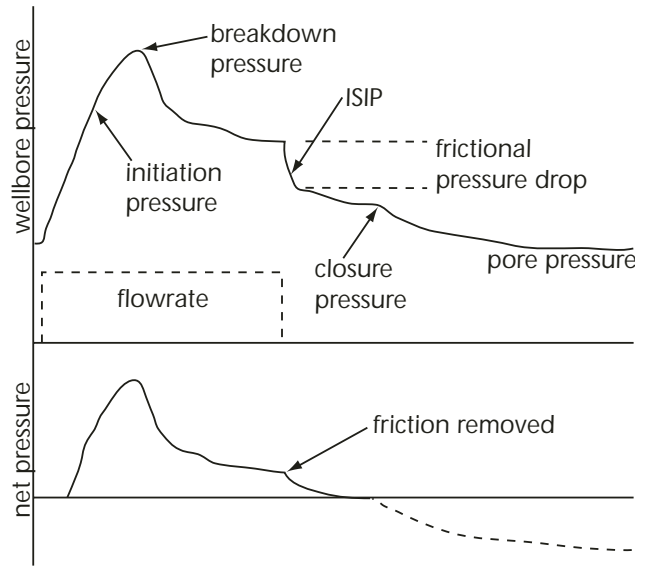
- 1 Clean-up the well and produce the well for some time. A subsequent pressure build-up can be used for determining the base transmissivity.
- 2 Perform a variable rate injectivity test by stepping up until the desired injection rate is reached. In the matrix flow regime, it is often easier to control pressure than flow rate. Once fracture is being propagated, the pressure is nearly flat with increasing rate and it becomes easier to control the rate. Often, the breakdown is not observed, but only the increase in injectivity after fracture opening is seen. The water should have the quality and temperature that it should have in the full scale produced water injection project.
- 3 Step down the injection rate to determine the fracture closure pressure
- 4 Inject for 2 to 3 days to establish steady-state conditions (of course, the required time depends on reservoir permeability). Shut the well in and observe the pressure fall-off (PFO) to determine the fracture closure pressure

Figure 5: Ideal behaviour during step-rate test



- 5 Run a spinner survey along with a temperature survey under steady state conditions, to determine the injection profile.
- 6 As a pilot test one could continue injection under fracturing conditions for two to six weeks to determine the trend in fracture propagation pressure.
- 7 Several fall-off tests may be carried out during this period in order to determine the change in fracture length and, possibly, the change in horizontal rock stress with time

Figure 6: Pressure response during an injection / shut-in test



The pressure fall-off can be analysed to determine the dimensions of the induced fracture. If the actual closing of the fracture is observed on a logarithmic pressure-derivative plot, the horizontal reservoir rock stress can be determined. A comparison with the initial stress as determined in the micro-fracture test then indicates possible poro- and thermo-elastic changes.

If the formation transmissivity has significantly increased compared to the reference fall-off case, the fracture has most likely propagated into another permeable zone.

If from the results of the in-situ stress measurements there appears to be a chance that, during the injectivity test, the fracture will propagate extensively into overburden and underburden, an attempt to monitor vertical fracture growth may be considered. Possible methods include:

- high resolution temperature logging
- gamma-ray logging
- hydraulic Impedance Testing
- acoustic (microseismic) monitoring

For all methods, reference logs should be run before fracturing. During the test the logging may be repeated at regular intervals.

A likely cause of increasing annulus pressure during the test may be leaking packers or temperature changes.

Conclusions on fracture height growth from annulus pressure observations would require a perfect seal of the tubing from the annulus. Careful analysis, using several measurements, is needed to establish a unique interpretation.

Hydraulic Impedance Testing can be used to estimate directly fracture dimensions. This technique involves generating a quick pressure pulse at the wellhead (by releasing a volume of about a litre). The reflection of the pressure pulse from the bottom of the well shows first of all the presence of an open fracture. Moreover, the character of the reflection can be used for estimating fracture size. The latter application is only feasible for simple completions, since the reflections can be severely disturbed by diameter changes in the tubulars. In any case the technique yields an accurate measurement of the fracture closure pressure, which is an important anchor point in the interpretation of pressure fall-off tests. In water injectors, changes in reservoir pressure and temperature can strongly influence the closure stress and it is very important to obtain additional data to constrain the interpretation of the fall off test.

The advantages of monitoring the vertical fracture growth and fracture dimensions are twofold. Firstly, it may be possible to terminate the test before unwanted communication with other reservoirs is established and secondly the maximum injection pressure may be established for which no such communication will occur.

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The International Association of Oil & Gas Producers encompasses the world's leading private and state-owned oil & gas companies, their national and regional associations, and major upstream contractors and suppliers.

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Mission

- To represent the interests of the upstream industry to international regulatory and legislative bodies.
- To achieve continuous improvement in safety, health and environmental performance and in the engineering and operation of upstream ventures.
- To promote awareness of Corporate Social Responsibility issues within the industry and among stakeholders.

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