Management of Salt Deposition in Gas Wells Guideline

Guidelines

October 2020

Executive Summary

This Guideline addresses salt management issues in Southern North Sea gas producing assets with the intention of capturing industry good practice on how adverse impacts of salt deposition in gas wells can be successfully mitigated and remediated.

The Guideline has been commissioned by the Oil & Gas Authority (OGA) and compiled by Lloyd's Register. A work group of Southern North Sea operators, co-ordinated by the East of England Energy Group (EEEGR), has contributed operational details and case studies, reflecting operator experience in managing the risk of salt deposition and associated issues in gas production. Significant technical input has been provided by Energie Beheer Nederland (EBN) and TNO – the Netherlands Organisation for Applied Scientific Research.

The Guideline is presented as a compilation of four underpinning parts, with supporting narrative drawn from case studies. The parts are set out in the following order:

a) Halite prediction guideline

b) Salt management guideline for field development and design factors

c) Salt management guideline for production operations

d) Salt management strategy guideline

It is the intention that the Guideline provides a general and easily accessible industry resource, built from up-to-date operator-focused insights. To support this objective, revisions will be made periodically to capture the latest developments in this fast-moving subject area.

Acknowledgments

In preparing and publishing this document, OGUK gratefully acknowledges the contribution of members of the work group, namely:

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• Eric Marston	Oil & Gas Authority
• David Roberts	Lloyds Register
• Eugenia Marinou	Lloyds Register
• Ricardo Gijbels	Energie Beheer Nederland (EBN)
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Within these guidelines the word 'shall' is only used when the instruction is explicit in legislation or physical laws. Otherwise the word 'should' indicates the Work Group's understanding of current good practice. “May” is used where there are alternatives available to the well-operator and either, or any one, of those alternatives is acceptable; in these instances, the well-operator will have to use its best technical judgement to decide which is preferable in the situation.

While the provision of data and information has been greatly appreciated, where reference is made to a particular organisation for the provision of data or information, this does not constitute an endorsement or recommendation of that organisation.

ISBN: 1 903 004 73 2
PUBLISHED BY OGUK

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Abbreviations	Definitions
bbl/d	Barrel per day
CAPEX	Capital expenditure
CBL	Cement bond log
CO_2	Carbon dioxide
CoP	Cessation of production
CRA	Corrosion resistant alloy
CT	Coiled tubing
(D)EGBE	(Di)ethylene glycol mono-n-butyl ether
EBN	Energie Beheer Nederland B.V.
EEEGr	East of England Energy Group
EFC	European Federation of Corrosion
FEED	Front end engineering design
FW	Formation water
FWGR	Formation water to gas ratio
GOR	Gas to oil (condensate) ratio
GWR	Gas to water ratio
HCO_3^-	Bicarbonate ion
HIIPS	High integrity pressure protection system
HUD	Hold-up depth
IPR	Inflow performance relationship
JT	Joule-Thomson
KCl	Potassium chloride
LR	Lloyd's Register
MEG	Monoethylene glycol
MMscf	Million standard cubic feet per day
$MMSm^3$	Million standard cubic metres
NaCl	Sodium chloride
NORSOK	Norsk Sokkels Konkurranseposisjon
NPV	Net present value
NUI	Normally unmanned installation
OGA	Oil and Gas Authority
OPEX	Operating expenditure
P_d	Dew point
pH	Acidity pH scale
PI	Productivity index
PLT	Production logging tool
ppm	Parts per million
P-T	Pressure-temperature (profile)
PVT	Pressure-volume-temperature
RO	Reverse osmosis
SI	Saturation index
SIG	Special Interest Group
Sm^3	m^3 at standard (gas measurement) conditions

Abbreviations	Definitions
SNS	Southern North Sea
SSSV	Subsurface safety valve
TDS	Total dissolved solids
TEG	Triethylene glycol
TNO	Nederlandse Organisatie voor Toegepast Natuurwetenschappelijk Onderzoek
UKCS	United Kingdom Continental Shelf (North Sea)
VLP	Vertical lift performance
WGR	Water to gas ratio

1 Introduction

The Oil and Gas Authority (OGA), together with Lloyd's Register (LR), EBN and TNO have undertaken a review with key operators to produce this industry good practice Guideline on the current state of salt (sodium chloride, halite) deposition risk management in offshore, NPNT southern North Sea (SNS) gas production assets.

SNS operators have identified that significant production losses can be incurred due to the formation of solid salt deposits (crystalline sodium chloride) at points in the production system ranging from reservoir/wellbore, wellhead, flowline and facilities [1, 2]. The salt risk is associated with the high salinity formation water common in SNS gas and gas/condensate reservoirs. SNS operators tend to approach the risk of salt precipitation in different ways - this guideline is to provide operators with industry recognised good practice for predicting the risk or mitigation of salt precipitation

In late 2018, following on from a publication by the OGA [1], representatives of the SNS operators formed an industry work group, supported by the OGA and co-ordinated by the East of England Energy Group (EEEGR), to share experience of managing the salt risk to production. A key element of the work group was to collate industry good practice on how salting is currently being managed into a single guideline document. The intention is that this document provides a general industry resource with input from SNS operators, but with application elsewhere. The guideline is hence intended to provide up-to-date operator-focused insights into how to address:

- Potential for salt precipitation in the well, flowline and facilities.
- Mitigation options implemented to prevent salt precipitation.
- Remedial actions undertaken to remove salt deposits.
- Operating and monitoring procedures.
- New field development and retrofit options for implementation during the development stage or during the field life.
- Building a fit-for-purpose salt management programme.
- Lessons learned and the shared experience.
- Potential for future advances and support for research.

Although the initial focus from a data gathering point-of-view has concentrated on offshore operations, where possible, experience from onshore assets in North-West Europe has been captured.

2 The Structure of this Guideline

Using the data gathered from SIG operators/members and experience from similar projects, the salt management guideline describes the practices that are or have been undertaken within the industry and captures operator perspectives on their management of salt-affected wells. The guideline is subdivided into four parts:

1. Halite prediction guideline
2. Salt management guideline for field development and design factors
3. Salt management guideline for production operations
4. Salt management strategy guideline

Each of these is accompanied by a supporting narrative drawn from case studies provided by SNS and land-based operators.

3 Salt Precipitation in Gas Wells

3.1 Context:

The aquifers supporting gas-bearing reservoirs of the southern North Sea contain formation water brines with a high dissolved salt content (up to a TDS of 320,000 mg/l). The brine composition is made up of a number of ion species, two examples are shown in Appendix A. As can be seen, the majority of the ionic mass is made up of sodium and chloride ions and this is a common feature of all oilfield formation brines. The overall salinity is often expressed as the total dissolved solids (TDS): a variation in the measured values of 10% as in this example, can be regarded as commonplace.

Under in situ reservoir conditions, the ion components of salts are in solution and chloride in equilibrium. Due to the production of hydrocarbons, the local equilibrium of the fluids in the reservoir changes; as a result, ions can become supersaturated in solution and this can lead to precipitation of solid mineral salt. Such salting has been observed in gas fields worldwide and is a feature of gas production across the UK and Dutch sectors of the SNS.

The term ‘salt’ is a generic chemical term usually meaning a solid that readily dissolves in water forming its constituent ions. The common salts that can form during oil and gas production are calcium carbonate, calcium sulphate, barium sulphate and strontium sulphate: within the industry these are loosely termed ‘scale’.

The primary concern for gas wells and the subject of this guideline is sodium chloride precipitation in the form of scale. This is referred to colloquially as ‘salt’ or halite (after the mineral) and for the purposes of this guideline the term ‘salt’ is used to refer to sodium chloride precipitation, as the solid. It should also be borne in mind that the other common scaling risks mentioned can and do occur in gas production systems: generally, the management of these scaling risks is well understood and for the reasons set out in this guideline can be considered secondary in southern North Sea operations, in comparison to that presented by salt precipitation.

Salt deposition occurs in mature, depleted gas fields, though can also occur in the early life of some wells. SNS operators have significant experience in defining the salt risk in gas and gas/condensate production and in recommending appropriate management strategies. This forms the basis of the technical information for this good practice guideline.

Most researchers in the area of salt precipitation in gas wells identify two primary mechanisms generally considered as the main triggers for salt deposition:

3.1.1 Gas stripping water from the produced formation water

The solubility of water in natural gas increases at lower pressures and gas can become under-saturated with respect to water as the pressure drops when gas flows into a well. In this case, salt deposition is experienced in gas wells with a low water to gas ratio (typically less than 5 bbl/MMscf). Water samples collected from surface facilities can be low in salinity (less than 10,000 mg/l total dissolved solids) due to dilution in the upper well trajectory by the condensed water from the produced gas. Salt deposition is most likely to occur near bottom-hole and at the reservoir interface.

3.1.2 Reduction of salt solubility at reduced pressure and/or temperature conditions

Salt deposition is experienced from gas wells with a high WGR (above 20 bbl/MMscf) where a substantial part of the produced water will be made up of highly saline formation water. Water samples collected from topside will show high salinity or be saturated with salt. Salt deposition is most likely to occur in the upper completion or at the surface facilities (Figure 1).

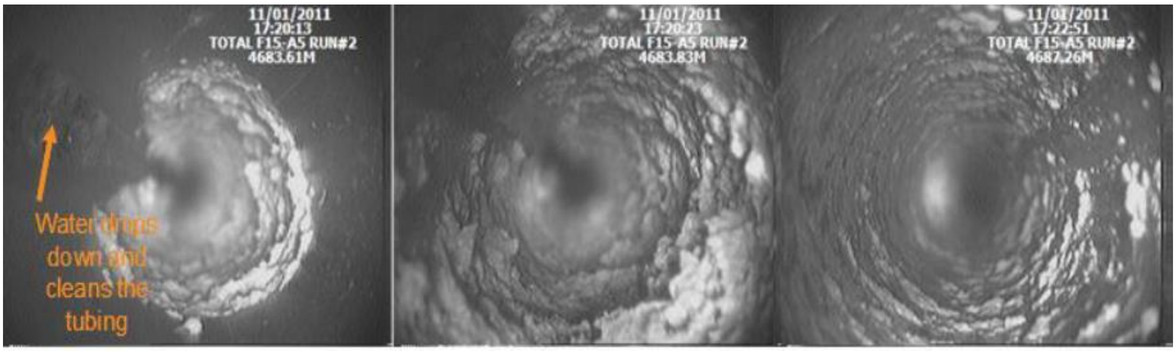

Figure 1: Photographs from a borehole camera run, showing salt deposits on the tubing wall (2)

Salt deposition mechanisms are supported by the wide-ranging studies completed in recent years [3-5] and provide a good theoretical basis on which to build understanding and establish reliable methods of treatment. The salt precipitation tendency can be defined in terms of the saturation index or saturation ratio and using industry-available software the salt risk envelope can be simulated for the anticipated production conditions. Published data use and regularly compare most scale prediction software packages currently available for salt deposition studies.

3.2 Impact of salt precipitation in gas wells

Salt deposition is relatively common in gas wells and is believed to be a problem for at least 20% of the SNS gas fields in the UKCS [1]. In the Netherlands offshore and land-based assets, 17% of gas fields are subject to salt precipitation issues [2]: in terms of wells, this represents 94 out of a total 855 gas wells. The total recoverable gas reserves affected has been estimated to be in excess of 5 billion Sm^3 [2]. Despite the prevalence of salting, there are significant gaps in the industry's ability to predict the propensity of salting and potential for formation damage.

Based on the OGA's 2016 UKCS Stewardship Survey, production efficiency for SNS operations was estimated at 64%. This is the lowest across the UKCS. The OGA estimated in 2018 daily production losses attributable to salt precipitation totalled 130 MMscf/d, equivalent to 20% of the UKCS total production losses [1]. Figure 2 shows the likely causes assigned to salt deposition events documented for UKCS wells in 2017.

The salt precipitation risk shows some dependence on reservoir pressure and drawdown. Reservoir pressure data indicates that the salt deposition risk is high for reservoirs with pressures lower than 100 to 150 bar, although exceptions are widespread: one SNS example cites a well lost to salt deposition with 300 bar reservoir pressure. Operators have adopted several mitigation and remediation measures to control salt precipitation risks or remove salt blockages from wells, including:

- Batch application of wash water, by bull-heading or tubing free-fall.
- Coiled tubing water wash.
- Continuous wash water into the well via capillary string.
- Setting a drawdown constraint.
- Intervention for reperforation, hydraulic fracturing or zonal isolation (water shut-off).
- Use of halite inhibitor.

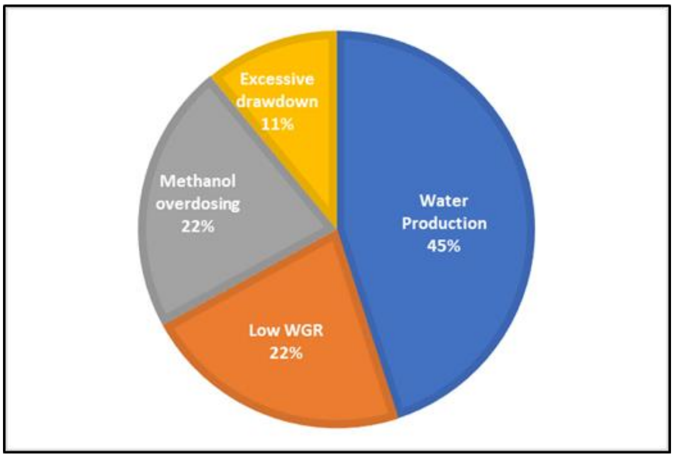

Figure 2: Causes of salt precipitation assigned to wells in UKCS fields (1)

From reported SNS operator experience, the relative success or failure rates of mitigation and remediation actions to control salt have been collated [2] and are shown in Figures 3 and 4.

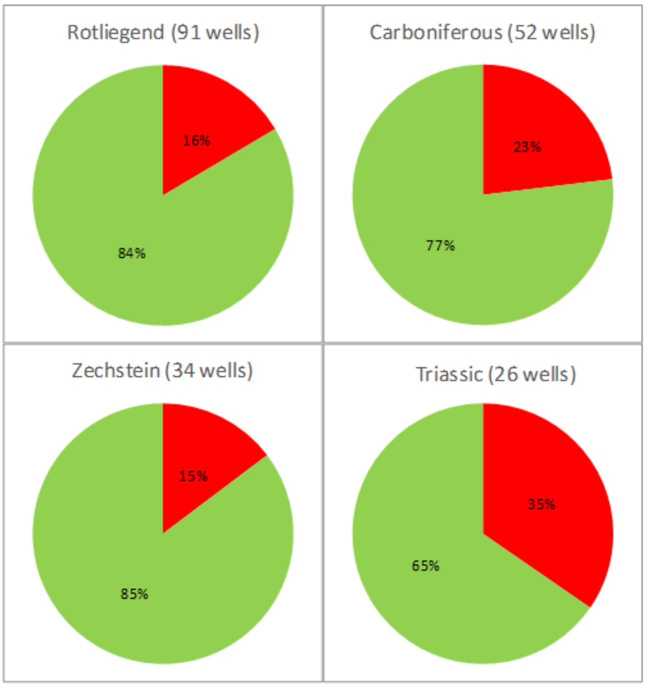

Figure 3: Well remedial activities for salt removal in 2017 in terms of successes (in Green), and failures (in red) (2)

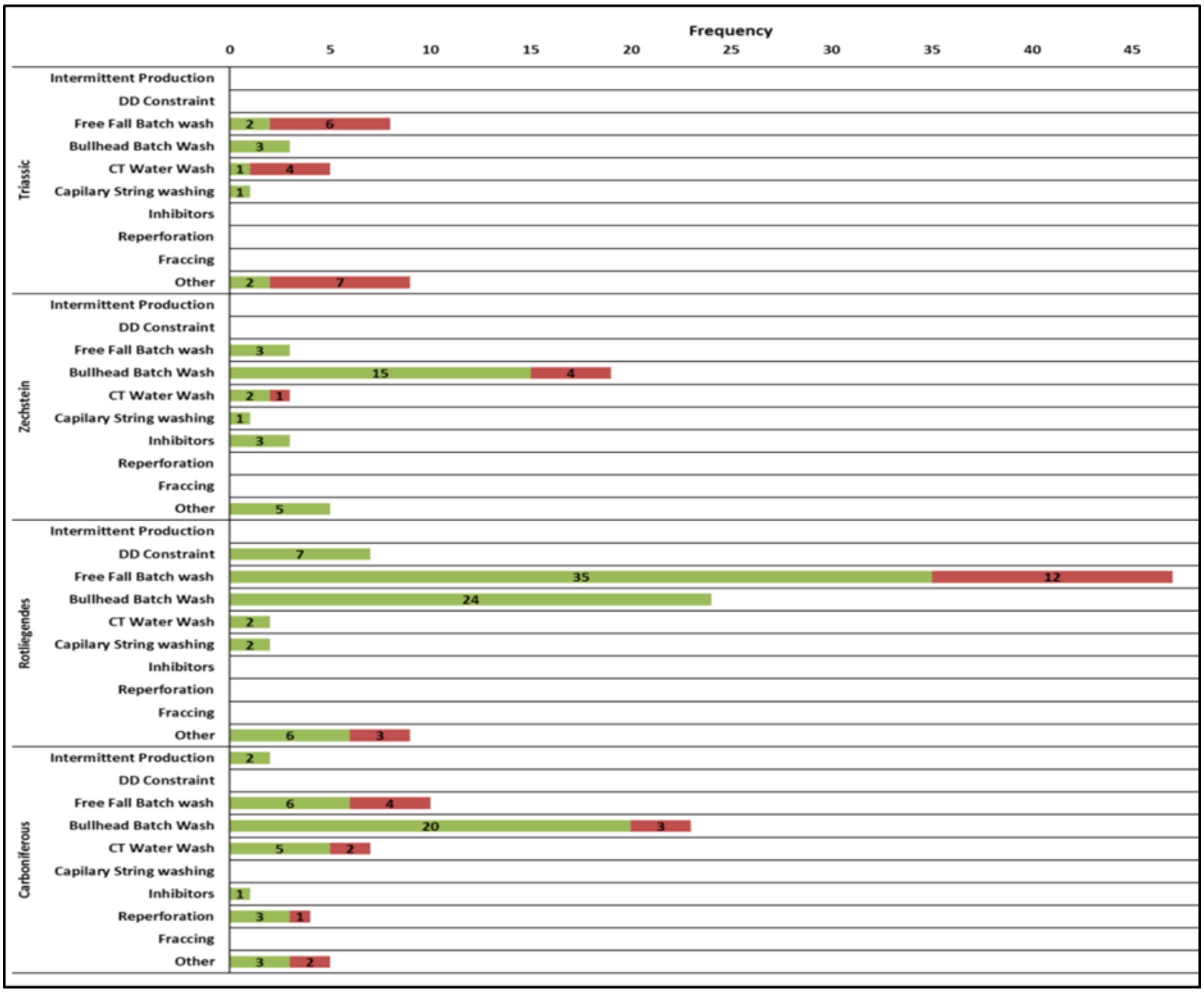

Figure 4: Well remedial activities for salt mitigation and removal in 2017 per type of operation (successes in green, failures in red) (2)

3.3 Capturing lessons learned and sharing operator experience

The statistics support the fact that the industry has made significant advances in recent years in managing the salt risk. However, it is important that case studies are documented and, where possible, made available in the public domain. There are opportunities for shared experiences to be discussed via special interest groups, for example, the annual focus group organised by EBN and the salt statistics collated by the OGA.

It is this intention that this document and its revisions will encourage ongoing improvements based on the dissemination of lessons learned.

4 Supporting Documentation and Guideline Updates

4.1 Data sources used in this guideline

4.1.1 Databases

The databases used for this guideline are:

- EBN Salt Forum database (2005 to 2018) [2].
- OGA database (2016) [1].
- EEEGR Special Interest Group survey (2019) conducted to inform this Guideline.

4.1.2 Survey (2019) questionnaire

A questionnaire was issued to the major SNS operators during early 2019 with a request to provide contextual experience for this study, bearing in mind limitations due to confidentiality, proprietary information, intellectual property or permission requirements to use the information and to quote analogue cases.

All available data have been compiled in a consistent order to reflect a common terminology and undertake a comparison of similar cases.

4.2 Document revision schedule and re-issue

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- Position your cursor where a landscape page is required and paste.
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5 The Salt Management Guideline

The guideline addresses salt (halite) management in southern North Sea gas producing assets and is presented as a compilation of four underpinning guidelines:

a) Halite prediction guideline.

b) Salt management guideline for new field development.

c) Salt management guideline for production operations.

d) Salt management strategy guideline.

1. The guideline is compiled based on published data, operator experience, laboratory studies and state-of-the-art modelling techniques in the public domain and undergoing implementation. Techniques considered at this time to be experimental or under trial are not part of the guideline but are referenced for future inclusion where appropriate.

2. Although it is recommended that all four parts of the guideline are followed, operators will select and prioritise their own approach to salt management as required.

3. Halite prediction studies provide the starting point for evaluating the salt deposition risk in the reservoir, gas well and production system (Guideline, Section 6).

4. Salt management options require addressing at the design stage of a new field and should form part of the structured design process from concept/select through FEED to detailed design (Guideline, Section 7).

5. New field development projects may include provisions for retro-fitted options to defer large CAPEX costs (Guideline, Section 7).

6. Salt management measures are an integral part of SNS production operations and require a systems-wide approach to ensure salt control procedures are properly understood and implemented in a cost-effective and safe manner (Guideline, Section 8).

7. The Salt Management Strategy addresses the factors that support a sound business case for setting out a proactive way to help secure the full value of the gas asset: the strategy can form part of the operator's Business Management System (Guideline, Section 10).

6 Halite Prediction Guideline

The halite prediction guideline recommends a procedure for assessing the risk presented to the gas production system by salt deposition either for new field developments at the design stage or for existing fields in production.

1. A fit-for-purpose halite prediction model should address the two dominant mechanisms responsible for halite precipitation in gas wells, namely:

   a) Downhole deposition caused by drawdown and evaporation of low-rate water in low WGR wells; this mechanism forms the majority of cases.

   b) Upper completion or surface deposition due to production of salt saturated water (in high WGR wells) and subsequent cooling along the pipeline, at surface.

   With salt-saturated produced water production, halite scale will potentially be observed at locations from near wellbore through to and including the surface facilities. Salt deposits seen at surface, in valves, chokes, etc., may be the result of downhole salt deposits carried in the produced fluids.

2. The principal input data for the model should be based as much as possible on measurable data from the field. This will include all or some of:

   a) Reservoir and production system pressure and temperature conditions.

   b) Reservoir hydrocarbon PVT properties.

   c) Reservoir formation water composition.

   d) Water gas ratio and gas dew point.

   e) Production rate.

   f) Identification of locations with the potential for significant pressure or temperature drops (for example: drawdown in the near-wellbore region, production chokes and safety valves).

   A robust model will include all measurables, (a) to (f), as inputs.

   The halite model will interface (manually or automatically) with the reservoir model, the lift (IPR/VLP) model, the flow assurance model (PIPESIM or OLGA), the process model (mass and energy balance, e.g., HYSYS) and the scale prediction model. Inputs and outputs from the halite model must be in general agreement with the other field models.

3. Output from the model should provide simulated values for:

   a) The point(s) in the production system most at risk of salt precipitation (scaling tendency).

   b) The mass of salt that may precipitate at key points in the system.

   c) The water injection rate for continuous water wash mitigation to avoid salt precipitation.

   d) The wash water volume required to dissolve a salt deposit (remedial batch water wash).

4. *Formation water chemistry and variation across SNS*: Where an exact, measured, formation water composition is not available, the typical basin reservoir formation water chemistry for carbonate and sandstone reservoirs should be used. North Sea formation water compositions are well-understood and documented in terms of the major ions in solution. Trended ion composition data from producing assets close to end-of-field life may provide accurate definition as analogues for new assets.

5. Model inputs should distinguish between commonly held definitions of water in the gas production system:

- Produced water: water separated from the hydrocarbon (gas) and collected at surface. In early field-life it may be largely condensed water and developing with increasing amounts of formation water as the field ages and the WGR increases (see salinity of produced water section).
- Formation water: water from the largely water-bearing zone underlying the hydrocarbon accumulation. Depending on water mobility and connectivity to the well, formation water may contribute to the water saturation of gas and to the produced water.
- Condensed water: water produced as water vapour together with gas, which subsequently condenses as liquid water when the necessary temperature and pressure conditions are met.
- Connate water: an immobile water layer in contact with the grains and particles of the reservoir rock and interfacing with the hydrocarbon in the pore space of the formation; contributes to and is in equilibrium with the water saturation of the gas in its natural state in the reservoir. Can be mobilised by evaporation effects due to dehydration in the near-wellbore region of the reservoir, leading to a theoretical contribution to the water saturation of gas.

6. The concepts of water saturation, super-saturation and under-saturation, with respect to the gas phase, should be defined by the model.

7. The model will interpret the extent of water saturation in terms of the level of evaporation and condensation in the production system and in relation to the pressure and temperature changes on production. Evaporation is defined as vaporisation of liquid water to an under-saturated gas; condensation is defined as condensed water dropping out from a super-saturated gas.

8. The model will account for *Joule-Thompson (JT) temperature changes*, typically encountered in relation to the pressure drop on drawdown and across chokes and valves.

9. *Water production over life of field*: The model is expected to predict the salt precipitation risk over life of field. This stresses the importance of robust production forecast and the reservoir model. There may be limitations associated with the reservoir model to predict water production especially during early production when most fields will be classed as ‘dry’ in terms of water production.

10. *Water composition data*: The methodology will provide for the validation of water composition data measured from water samples. Point of sampling (at downhole, wellhead, or separator) and the pressure and temperature conditions at the time of sampling can have profound effects on the measured water composition and its relation to the formation water composition. The impact of dilution by condensed water on surface water samples will be subject to the validation step. The aim is to correct the measured water composition data back to the best estimate of the in situ reservoir formation water composition.

11. The production system for modelling purposes should consist of (as a minimum) requirement reservoir, well, wellhead/flowline and separator and use as inputs the relevant flow rate, pressure, temperature and WGR at each of those nodes. Additional definition to cover locations with the potential for significant pressure or temperature drops (for example, drawdown in the near-wellbore region, production chokes, separator conditions) should be included as primary inputs or sensitivities.

12. The model will derive the hydrocarbon phase envelope and estimate the extent of water condensation or evaporation at the relevant pressure and temperature nodes in the process.

13. Limitations: it is necessary to stress the importance of *good quality input data* but within the confines of what is reasonably possible. Table 1 identifies the minimum data requirements for the pre-production new field design case and the late field life case where there is likely to be an established production history. Inherent to the dataset will be approximations and assumptions to fill data gaps, sensitivities to cover common areas of inaccuracy and uncertainty, and an appreciation of ways of improving input data accuracy and reliability. For the mature field, routine monitoring programmes can have the required depth of data analysis to directly influence the robustness of the prediction model and to inform decisions around ongoing field development and retrofitting equipment.

    It is important to identify any uncertainties or limitations associated with forecast production profiles. Production profiles are usually expected to be reliable in terms of hydrocarbon production over life of field but less reliable in terms of water production and specifically the fraction of formation water to condensed water that makes up the produced water. Production models are usually less stringent with respect to water, and carefully chosen approximations and assumptions need to be made in the salt risk assessment.

    The modelled halite risk assessment is only valid for the reservoir temperature, pressure and water composition used as input data: it is not possible to apply with confidence the outcomes from one model to an asset with a markedly different input data-set.

    Water production for a gas well is particularly challenging in early field life where the reservoir model often shows a dry (zero water) production. The accuracy of that prediction is fundamental to defining the salt risk and places additional emphasis on selecting reasonable scenarios including a developing WGR.

Table 1: Data reliability and uncertainty

Component	**Confidence level**		**Primary (default) data source**
	Early field life	*Late field life*	
Reservoir pressure	High	Low	Measured
Reservoir temperature	High	High	Measured
Formation water composition	Low	Low	Analogue data
Water production rate	Low	High	Modelled
GWR	Low	High	Modelled
Gas composition	High	High	Measured
Gas production profile	High	High	Modelled
Produced water composition	Low	High	Measured

Of the input data listed in Table 1 poor quality (or no) specific water data for the halite model, or a reliance on analogue data, will have the greatest bearing on the robustness of the model, potentially resulting in an over-conservative prediction. The water composition should be scrutinised and adjusted to provide a number of case-sensitivities for input to the model, with the aim of compensating for any contamination or loss of solids during sampling. Figure A1 in Appendix A shows indicative ranges of ion ratios for SNS formation waters that can help set up reasonable cases for the halite model [5].

14. Newer versions of the halite prediction model (see Section 11) aim to give the drawdown limit and the plan is for users to update the model every one-to-two years, using real production data.

15. Tools and software: Widely available tools and software to model all or part of the halite precipitation risk may find suitable application. Advantages and limits of commercialised halite prediction software packages are described in Section 11.4 together with a discussion of state-of-the-art approaches which are finding increased application. In general, the halite prediction software should be capable of addressing:

a) Halite solubility in water, simulated using geochemical thermodynamic scale algorithm (such as *OLI ScaleChem/Stream Analyser, Solmineq, ScaleSoftPitzer*).
b) Water content in the produced gas, simulated using the phase behaviour algorithm (e.g., *KBC Multiflash, Calsep's PVTsim*).
c) The impact of JT cooling at a given pressure drawdown, determined using the phase behaviour algorithm in (b) above.

6.1 Halite prediction – supporting narrative

Operating conditions that may encourage the precipitation of salt can be examined using halite precipitation models [5-6]. Halite modelling is highly sensitive to water composition and WGR and both are difficult to measure accurately with shared flowlines and production separators. Similarly, allocation of salt-related issues back to individual wells is a challenge with commingled production. It is important to stress once more the need for good quality input data; data gathering should be pursued at every opportunity.

The value of halite modelling at the design stage is often to express the salt risk in terms of uncertainties and to justify including mitigation options such as completions fitted with downhole capillary string injection to reservoir depth and topsides facilities with provision for wash water treatments.

For many operators, the halite envelope is derived during the design phase of the project. Very often, the initial reservoir model typically shows zero water and it is now becoming acceptable to reassess this to show a low but significant WGR.

The design-stage halite study also impacts downhole materials selection and halite modelling is instrumental in providing an informed worse-case for the chloride level in produced water, for the purpose of modelling the corrosion risk and laboratory testing as necessary.

Predictive model usage for performance diagnostics has progressed to the point now where confirmation of strategy can be derived from the simulation of halite envelopes [5, 7]. In one operator's example, the model explained why a well in an SNS asset responded poorly to shut-in/open-up procedures to control salt build-up and clearly indicated that if a capillary string could not be installed on an NPV cost basis, the well should be abandoned as the only viable alternative, which it subsequently was.

6.1.1 The halite deposition envelope

In contrast to the more familiar oilfield scales such as calcite and barite, there are multiple ways of expressing the salt risk envelope (examples are shown in Figure 5, Figure 6 and Figure 7) and this adds a level of complexity which can often discourage take-up of simulations and very often can limit the usefulness of the outcome. Note that the illustrated output is only valid for the reservoir temperature, pressure and water composition used as data in the halite model and the charts do not represent generic outcomes.

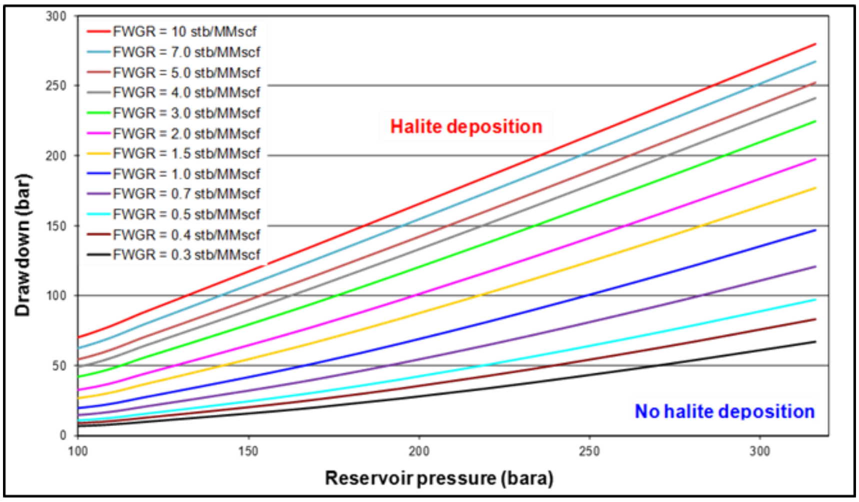

Figure 5: Example of a salt risk envelope defined in terms of drawdown with FWGR sensitivities (5)

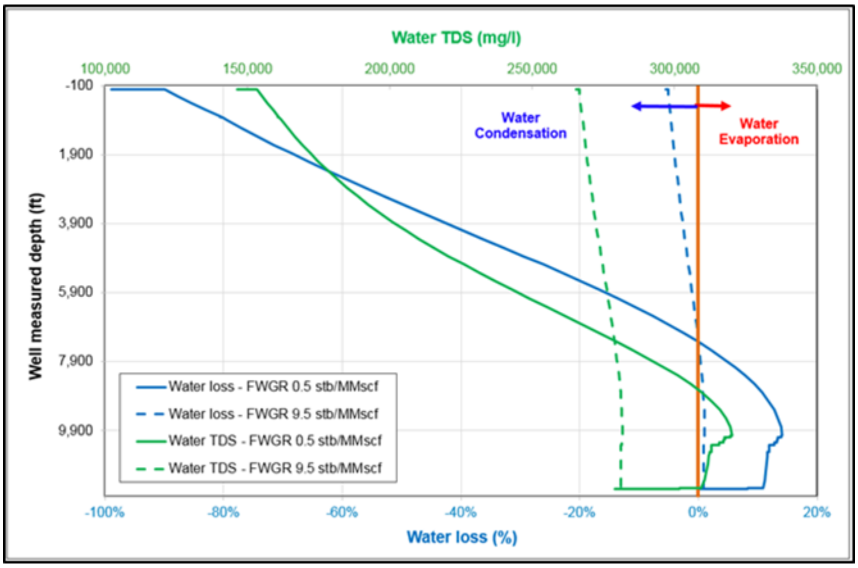

Figure 6: Example of a salt risk in terms of simulated water condensation and evaporation in the well (simulations by Lloyd's Register)

Recently, operators have been engaged in better defining fit-for-purpose ways of representing the salt risk envelope and to relate the outcomes to easily measurable data that can be added into routine process monitoring programmes for offshore. Empirically derived operating envelopes of the type shown in Figure 7 have been collated for some individual gas producing assets.

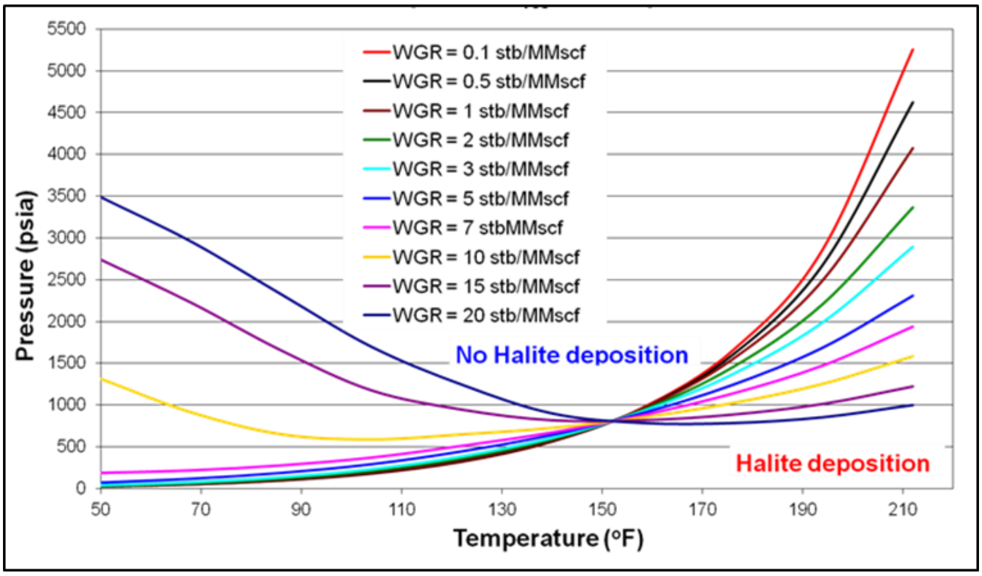

Figure 7: Example of salt risk expressed in terms of the calculated water loss due to evaporation and for various WGR's, at a constant reservoir pressure

6.1.2 Outline of modelling procedures

Ultimately the challenge for the halite prediction model is to be directly relevant to the requirements of field development or well operations. In this respect, the most relevant outputs from halite prediction modelling will be the predicted mass of the salt deposit that can potentially form, and the wash water volume required to dissolve it. A typical procedure will involve several steps:

- Calculate the water evaporation/condensation at a given reservoir temperature, pressure, drawdown and water to gas ratio, as shown in Figure 6. The water content in the produced gas can be simulated using phase behaviour software (e.g., KBC's Multiflash or Calsep's PVTsim), or nomographs of the type shown in Appendix B.
- Determine the salt solubility in water and the tendency to precipitate using geochemical scale risk software (further details in Section 11.4).
- Use inflow and well performance relationships (for example, Petroleum Experts' Prosper software), to define pressure and temperature gradients in the flowing well and to identify liquid loading conditions.
- Determine the volume of fresh water needed to compensate for the water evaporation (or KCl wash water, if applicable) using scale prediction software. Calculate the amount of salt mass that can dissolve into the water volume. This indicates the minimum wash water volume to dissolve the salt mass under the operating conditions selected.

It is important to appreciate that the halite prediction model is not a single case model for all wells and for life of field. To be fully robust, the model should be revisited to reflect the development of a new field through the design stages and into production when new data is available. Figure 8 shows schematically how the review and refine cycle can be set up.

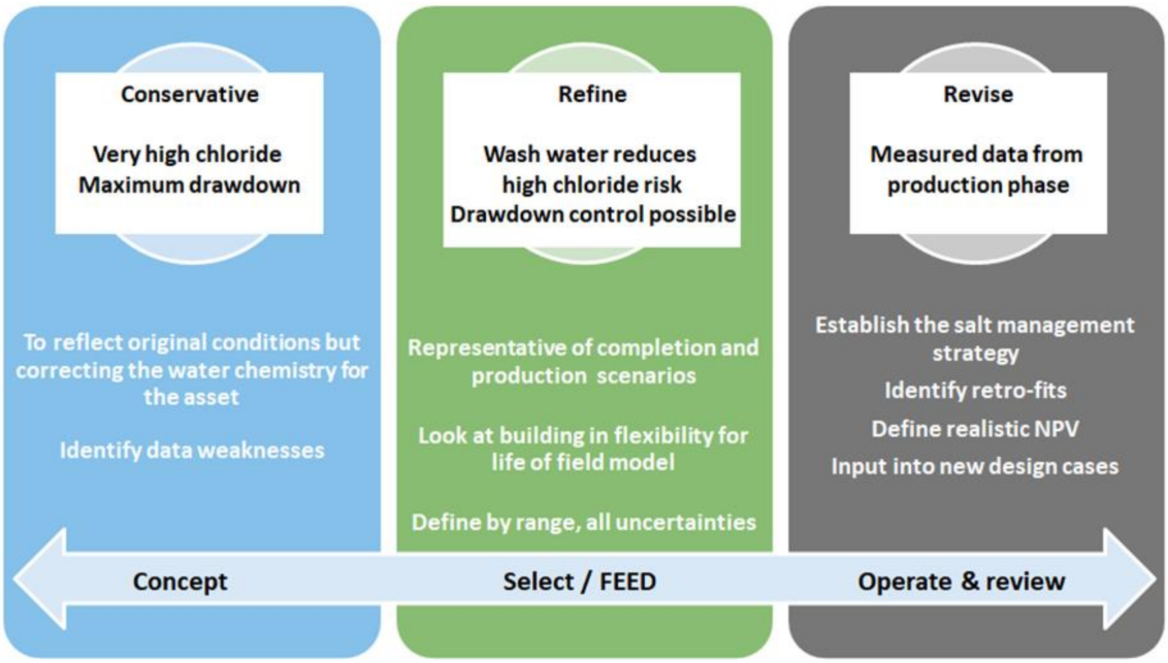

Figure 8: The halite model simulation cycle

A full halite diagnostic procedure will use multiple modelling steps iteratively and updated regularly, when new data are available. For example, a typical procedure can be:

- Perform the IPR/VLP correlation for the well to establish the Turner critical rate for liquid loading, using Petroleum Experts' Prosper (or equivalent) model.
- Run the halite prediction model.
- Identify the salt precipitation condition in the Prosper model.
- Perform life of field simulation for forecast decline rate, NPV, ultimate recovery and cessation of production.
- Examine OPEX and CAPEX options in the simulation, e.g., well entries, recompletions, water wash operations.

6.1.3 Software availability and usage

Commercially available software for halite prediction modelling is discussed in Section 11.4. Current operator preference for halite prediction software is *OLI's ScaleChem with Stream Analyser* from *OLI Systems*. Output from the model allows the setting of drawdown limits. One SNS operator, over a period of several years, has matched the model to existing salt producers and found better than 95% agreement. Alternatives are available, including TNO's Saltmux, Expro Petrotech's Multiscale [20], Scale Consult HalOpt and LR's Solmineq.

Depending on the availability of new data, updating the model every one-to-two years should in many cases be possible. This is helped by a commitment to run wireline hold-up depth (HUD) and bailer when wells are entered for suspected salt blockage.

The main limitation of halite predictive software is that significant experience in its use is required to prepare input data and interpret outcomes. However, despite the software's specialist nature, SNS experience suggests that a multi-disciplinary team is able to use the model with appropriate discretion, all aware of the limits of application and the need to test model sensitivity to uncertain data.

TNO's latest halite prediction model [6] is undergoing field trials (in 2019) with real well data. The main advantage of the TNO model is that it predicts the amount of salt deposited and, therefore, the volume of wash water to dissolve the mass as well as the optimum timing of the water wash. It is anticipated that the new model will provide a more proactive means of addressing salt problems.

<u>Model sensitivities</u>: the robustness of inputs should be tested in the model to examine the impact of inaccurate data. This is particularly important for the water composition and the salt saturation level. It is also necessary to interrogate the reservoir model thoroughly to achieve an appropriate level of confidence in the water production forecast; predictions of an initial "zero produced water" should be examined carefully.

6.1.4 Model benchmarking

Laboratory-based studies have been used to define the salt deposition risk and test mitigations and remedial measures [5, 8-10]. Detailed research and field trials address:

- Threshold halite scaling conditions.

- Halite inhibitor test-work and treatment optimisation.
- Effect of water soak volume and frequency on the well.
- Salt deposition in the reservoir: Laboratory core studies have been undertaken in core plugs to quantify the impact of salt deposition on the extent and speed of performance loss.

The above are still active areas of research and field investigation with outcomes immediately feeding into enhancement and calibration of the halite prediction models.

It is important that this work continues and receives operator support: wherever commerciality considerations can be set aside, a commitment to publish field trials and laboratory research will enhance industry confidence in improved halite risk predictions and the ability to fully exploit asset value.

6.1.5 Horizontal intervals

Horizontal well sections present a challenge for predictive modelling, from an inflow point of view. In some cases, observations suggest that the well trajectory in the horizontal section can show low points that could initially be water-filled, giving an anomalous WGR. In general terms, well interventions allow opportunities for camera and bailer runs and production logging in the horizontal section will provide inflow data, all of which assist in interpretation and refinement of the models. Similarly, the response of a horizontal interval to a remedial water wash can be aligned with predicted model outputs, and input parameters can then be adjusted to improve the robustness of the model.

7 Salt Management Guideline: New Field Developments

The guideline addresses new field developments and the challenge presented to the design team to evaluate the key implications stemming from the perceived salt precipitation risk. The available data is in many cases limited in scope and quality: for example, the data-set for the reservoir fluids might comprise a PVT hydrocarbon analysis with an unreliable formation water composition. There is a cost vs. benefit association for additional data gathering at the development stage: in general, in the absence of specific test data, the use of analogue data (e.g., formation water composition, near field production history, offset wells, etc.), proves to be a robust way forward for a mature basin such as the Southern North Sea. This suggests there is as great a requirement as ever for operators to share, exchange and document common experiences. It should also be recognised that key design inputs for addressing salt risks are not all engineering-based and specialist chemistry expertise is required at the earliest stages.

7.1 Design stage infrastructure considerations

7.1.1 Subsea tie-back development option

Subsea tie-backs have reduced accessibility compared to installation-based wellheads. Consideration should be given early in the design process to how water wash capability can be built in, even if this is to be deferred as a retro-fit option. Subsea developments are often capital-constrained and tie-backs present a cost-effective option for smaller assets.

The engineering options for salt mitigation in new subsea developments will usually include:

- *Equipping each well with a capillary string for continuous wash water injection*: Delivery could be via umbilical from the host facility, assuming wash-water is available at the host and if pump pressure and injection rate requirements can be met. This might be a significant part of the capital outlay per well.
- *Designing for periodic bull-heading of wash-water*: This could be from a support intervention vessel, where multiple wells are treated as part of a campaign and the primary requirement would be for ROV access at the subsea trees. The intervention vessel would be expected to supply wash-water and could also accommodate clean-up of the well after treatment. Various subsea infrastructure options, for example, daisy-chain vs. manifold choices, can also determine how much flexibility there is for treating individual wells by bull-heading. There could be an option for a coiled tubing intervention if later experience from bull-heading showed improved diversion in the well would be advantageous.
- *Monitoring capabilities*: Individual well telemetry with downhole as well as surface gauges will be important, and some built-in redundancy will be advantageous. Wells that are forecast to cut formation water at different periods may require individual well control and monitoring capabilities.
- *Access to methanol for hydrate inhibition is likely to be required on a well-by-well basis to avoid hydrate risks when back-producing saline water from a water wash*: If a shared, inter-asset, methanol capability is part of the design it should be confirmed that the shared facility is able to accommodate sufficient flexibility to cover hydrate inhibition and provide a turn-down option to avoid salting risks after bull-heading wash-water.

Ultimately at the design stage it is a question of how the perceived salt precipitation risk is balanced against either the cost of mitigation or periodic remedial treatments. Part of the risk will be related to the level of confidence in the reservoir model, particularly concerning water production and this should be appropriately scrutinised by the development team early in the design process. Some of the risk will have to be carried through the design stages because of poor quality (or no) water data for the halite model and the implications of a potentially over-conservative prediction need to be fully understood and factored into concept selection.

7.1.2 Platform and NUI development options

There are advantages in producing to platform facilities compared with NUIs when implementing a salt management strategy. Platforms offer increased flexibility to address salt management with improved accessibility and the potential for optimum treatment, maximising production. Similarly, shared hub facilities, such as wash water and shared chemical treatments could limit flexibility.

7.1.3 Water-cut development and life-of-field requirements

In most cases the rising water table or channelling via natural or hydraulically induced fractures means that wells originally considered to be producing at zero WGR or too low to measure, start producing formation water. Life-of-field considerations need to address salt management requirements over a wide range of production scenarios, commencing with early onset issues characterised by very low WGR to production of high salinity formation water.

Water-cut development: for many new field cases initial WGR is modelled as zero, as any water that may be produced will be small volumes of condensed water. It is recommended that the design assumes an initial water salinity and the risk of water breakthrough is assessed, through an understanding of:

- Vertical stand-off and lateral stand-off from water gas contact.
- Formation homogeneity.
- Fractures (e.g., Zechstein and Carboniferous production in Germany and in some North Sea examples [9]).

Provisions for mid-to-late field life need to consider declining reservoir pressure due to depletion and increasing formation water production:

- Salt deposition risk increases with depletion.
- Liquid loading risk increases with depletion.

Increased formation water production will increase the risk of:

- Salt deposition.
- Other scales (typically co-precipitated) which may also need mitigation.
- Liquid loading.
- Sand/fines production.
- Increased corrosion risk and heavy metal scale.

7.1.4 Design basis

It should be assumed in the Basis of Design of green field developments that water injection using wash water into the gas production well or production flowline will be required at some point in the field life.

The capacity to bullhead wash water from the facility down each well should be viewed as a minimum requirement. Appropriate provision for this service should be carried through at all design stages with the challenge to rule out rather than rule in. CAPEX costs associated with salt management are unlikely to be prohibitive in terms of progressing a project through design gates. There can be a synergy with the material selection considerations for well tubulars and pipelines: installing wash water facilities for salt control may also be effective in reducing chloride levels potentially favouring lower metallurgy options.

7.1.5 Well targets

New well designs should avoid completing close to the gas water contact or in poorly homogeneous or fractured formations.

7.1.6 Retrofit capability built into design

In general, uncertainties around forecasting the onset of water production and the accuracy of the formation water composition data mean that careful consideration should be given to the following options:

- *Build in salt management capability for field start up*: advantages include preparedness to cover uncertainties and; disadvantages include up-front CAPEX that affects NPV and the need to maintain mothballed equipment.
- *Defer salt management capability for retro-fitting later*: advantages include knowledge gained form early production will inform the choice of mitigation; disadvantages include lead-time and time to build which will incur production losses.

Retrofitting a capillary string in the well completion is an option taken up by some SNS operators and new technology using the wet-connect system through the SSSV should allow retro fit. This will require a well intervention: platform and NUI facilities will need provision (deck space, hoist capacity) for conducting well interventions. As a minimum requirement, preparatory design at the outset should include provision for tie-in points and spools for connecting future wash water facilities and assigning tank and pump space on deck.

Certain strategies for pre-empting future mitigation options should only be proposed with caution at the design stage because of limited success or field experience. These include:

- Water shut-off in gas wells: evidence of activities to set bridge plugs and straddles to control water influx into the well suggests a high risk of failure.
- Use of a stand-alone halite inhibitor deployed via umbilical: halite inhibitors are still largely under field trial and current chemicals are not yet proven in terms of effectiveness as the sole method of prevention.

7.1.7 Production profiles and forecasts

Production profiles are usually expected to be reliable in terms of hydrocarbon production over life of field but less reliable in terms of water production – and specifically the fraction of formation water to condensed water that makes up the produced water. Production models are usually less stringent with respect to water and carefully chosen approximations and assumptions need to be made in the halite risk assessment.

As stated in Section 7.1.3, this is particularly challenging for modelling early field life where the reservoir model often shows a dry (zero water) production. The accuracy of that prediction is fundamental to defining what can be a serious salt risk and places additional emphasis on selecting reasonable scenarios including a developing WGR. It is a difficult compromise to address over-conservative margins that may disfavour and even halt a new development without taking on too much risk in terms of not having the necessary provisions in place when the field is brought into production.

7.1.8 Completion design

- *Philosophy*: The completion philosophy should aim to facilitate water washes below the packer and down to reservoir depth. Remedial deep downhole water washes can be achieved by bull-heading wash water or with the use of coiled tubing. However, recent operator evidence indicates it is expedient to install a deep-set capillary string as part of the completion to provide a continuous mitigation option.

  Wells completed with capillary string above packer will not be as effective at maintaining salt control as completions with the capillary string run through packer to reservoir depth. Capillary strings run to below the packer will enable wash water treatments down to the reservoir formation depth. However, access is currently restricted to well designs based on vertical or deviated completions.

  For deep downhole capillary strings, packer by-pass systems can be utilised (similar to the connector systems for intelligent well operation). Multiple penetrations for more than one capillary string are possible, but the tolerance in the liner needs to be considered. Capillary strings can be ¼ inch or ½ inch diameter; running two or three capillaries in the same well increases the wash water delivery (3 x ¼ inch gives approximately 8 bbl/day wash-water injection). Downhole capillary to reservoir depth can be run behind sand screens with Schlumberger's *Wet-Connect (Wet-Mate);* note that there were failures in running the capillary, roughly 1 in 4, but considered as an essential part of the completion.

  For long horizontal producing intervals, deep capillary strings can be run below packer to the heel of the horizontal section. The horizontal section is likely to remain unprotected from salt risk, therefore full consideration has to be given to the value in running the capillary strings as the horizontal section will probably respond better to water-washes.

- *Fouling of the capillary line [2] has been observed*: Boroscope camera investigation has shown microbial growth in the tubing probably associated with continuous water injection. Use of a suitable biocide additive in the wash water may be required.

- *Sensors*: Completions ideally should be fitted with permanent downhole inflow sensors for temperature and pressure measurements across the lower completion. Wellheads/trees should be individually fitted with permanent temperature and pressure sensors; the requirement also extends to platform (dry) trees.
- *Cement bond log*: Where possible at the completion stage a CBL should be run to confirm the quality of the cementation behind production casing and liner; this is fundamental for informing future water-shut off choices.

7.1.9 Wash water supply

The selection of the optimum water supply for wash water injection should address the following:

- The ideal wash-water salinity, bearing in mind the risk of clay swelling in water-sensitive formations. There may be a need to differentiate between tubing-only treatment (for example, capillary string continuous water injection) and wellbore/reservoir washes where contact with the reservoir might be either inevitable or desired. Addition of KCl or commercial clay stabilisers to fresh water is an option used by operators.
- Seawater may be a possible alternative, but weight-for-weight has less salt dissolving power than low salinity or fresh water.
- A reverse osmosis (RO) package can be used for obtaining a low salinity or fresh water from seawater.
- Corrosion control will be required, by removal of oxygen (down to a target of 10 ppb) by deaeration and injection of oxygen scavenger.
- Fouling of the capillary string: might require capacity to add biocide or inject a batch biocide treatment into string.
- Hydrate inhibition, some inhibitor content will be required for back production of wash water (see Section 9.3).
- Foam water treatments: addition of a foaming agent improves lift.
- Water delivery pumps – for multiple capillary strings ideally independent pumps should be in place, dedicated to each capillary string as this ensures delivery and covers maintenance requirements.

7.1.10 Impact on material selection

Material selection for well completions and pipelines requires careful consideration of produced water salinity and pH. These factors will be addressed by the relevant disciplines in the project team, but it is necessary to acknowledge and work with the common ground between corrosion and halite studies.

It is understood that produced water composition has a major impact on materials selection for well tubulars and flowline and the acid corrosion rate is determined largely by water pH, which is related to acid gas solubility in saline water. The worst case for corrosion is presented by condensed water (because of maximum CO_2 solubility and minimum pH); whereas there would be a reduced risk in formation water brine. In addition, high salinity brines on the other hand, may be prone to inducing chloride stress corrosion cracking especially in combination with poorly deoxygenated wash water.

Therefore, salinity and pH are fundamental requirements for materials selection at the design stage and for corrosion monitoring and mitigation. Measured values of the salinity of produced water in surface samples may be inaccurate. The requirement here is to understand how the produced water composition can be related back to a likely ratio of formation water and condensed water. This is important for existing production where water composition data may exist but require a robust interpretation. It is interesting to note that for corrosion studies, the European Federation of Corrosion, [17], provides a definition of condensed water as one containing up to 1,000 mg/l NaCl (or 600 mg/l chloride ion concentration).

Oxygen control is also an essential requirement for injected wash water and this will have impacts on selection of well completion materials.

7.1.11 Summary of challenges and impacts

A summary of the corresponding design challenges and impacts when it comes to producing fields prone to salt deposition is given graphically in Figure 9.

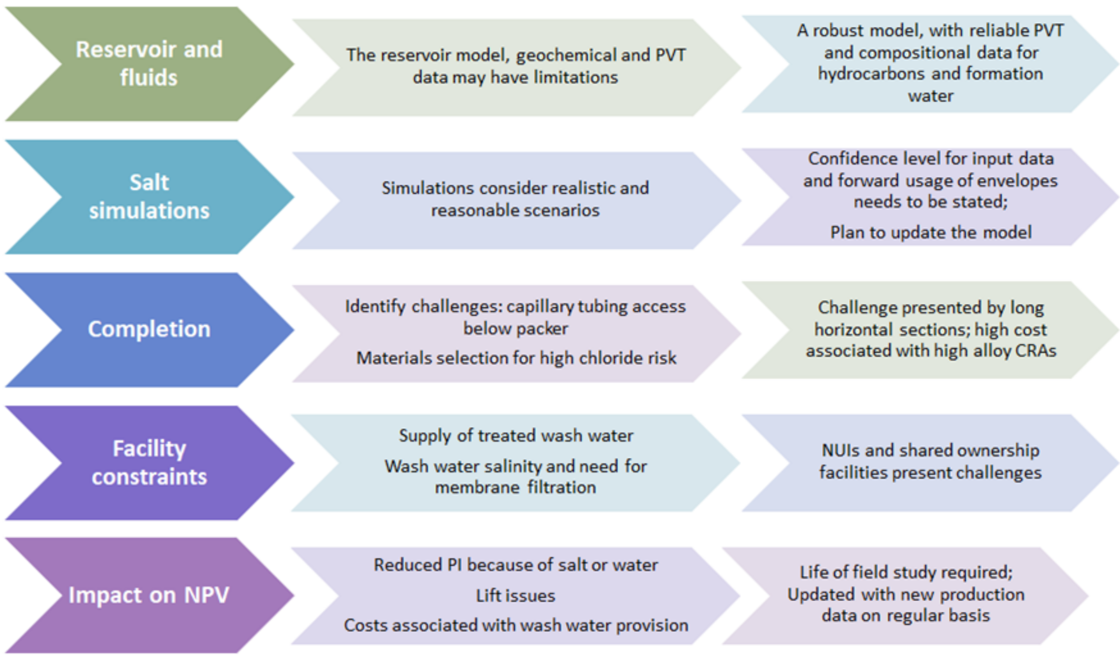

Figure 8: Summary of challenges and impacts associated with the production of fields prone to salt formation and deposition

7.2 Salt management for new developments – supporting narrative

For SNS operators, surveys show that sufficient knowledge of the salt deposition risk is present in the company which enables development teams to be proactive at the design stage of a new field development. This is in contrast to recent history when the factors leading to salt deposition in gas wells were poorly understood and very often the design basis that was carried forward adopted a wait-and-see approach.

Now companies are prepared to work with risk-levels to define future salt mitigation/remedial options, in the same way as the other mineral scaling risks are handled. There is an acknowledgement that new developments in the SNS will likely take place in areas with a high probability of salt problems and it is increasingly recognised that the key design inputs for salt control require specialist chemistry expertise at the earliest stages.

A large part of the growing confidence in managing salt problems is due to the rapidly developing knowledge base and modelling capability. Measured data and rigorous testing has underpinned the effort: one operator can report that where there is confidence in the water chemistry and production forecast not much guess-work is involved.

Salt management concepts are increasingly integral to the reservoir assessment, modelling and well plans and operators are drawing on shared and in-house experience strongly supported by evidence.

Typical design phase decisions involve selecting a host platform or dedicated NUI. New developments tend to start with two to three wells, mostly high angle, though horizontal wells are also a feature of SNS operations.

At the concept-select phase the potential impacts of a salt deposition risk are being increasingly addressed by SNS operators, and emphasis is given to:

- Completion design with capability to continuously inject water via a capillary string [11].
- Surface facilities design: water wash infrastructure or retro-fit capability as a minimum requirement.
- Completion away from water leg, though acknowledging that water-cut development will occur over life of field.
- Adopting well control measures with choked-back production (lost production) as an alternative (do-nothing) case.

In terms of economics, it is appreciated that any additional up-front CAPEX or life-of-field OPEX for mitigating salt will decrease the NPV of the project. But the challenge is increasingly focussing on comparing the risk-based associated costs with the consequences of not including the mitigation and the reduced gas recovery. Operators feel the current state of knowledge of salt deposition within the SNS operator community enables a proactive approach at the design stage of a new development. This facilitates working with risk-levels to define future salt mitigation/remedial options and where there is still guess-work it is better informed guess-work than it used to be.

The result is a balanced approach: applying fit-for-purpose mitigations and avoiding either the do-nothing case or an over-conservative adoption of salt management procedures, both of which ultimately threaten the viability of the project.

For example, one operator's new field design required inclusion of downhole chemical injection lines for water wash treatments. For their next, high profile development, careful analysis of the risk-levels indicated that a downhole chemical injection line is not required but there will be provision of space and the tie-in points for the installation of a package to allow fresh water flushing of the well to remediate salt deposition, in the event that this is eventually required.

It is now appreciated that salt management concepts at the design-stage will impact materials selection for the well completion. Initially this led to fears of corrosion risk assessments being much too conservative in accounting for the potential risk of saturated salt solutions and resulting in high cost alloys being proposed for completions and flowlines. One operator reports their access to high quality data and their growing salt management experience allowed the design team to challenge on a risk-basis the selection of a high grade CRA in favour of a lower grade – subsequently confirmed as the right choice by laboratory testing at the expected field conditions.

Planning for remote facilities for salt management (wash water bull-heading or continuous injection) plays an increasing part in setting CAPEX budgets for new developments.

Regular water washes of the tubing and lower wellbore have been successful in mitigating against salt deposition and it is known from experience that failure to wash routinely has resulted in the loss of production to a point where restoration is increasingly difficult. This experience has supported designing and installing remotely operable facilities to allow for more frequent washing at the optimum point in the well's production cycle.

In general, the perceived salt risk will have an influence on new development design factors as it will impact the NPV as a result of the CAPEX or OPEX incurred in mitigating or removing salt deposition, therefore, every case has to be thoroughly examined on its own merits. It is now possible to do that with increased confidence.

For new developments, sourcing wash water will be a major cost consideration, discussed further in Section 8. Options to consider include:

- Platform-built capability including options for deaeration towers and RO plant (small-scale deaeration units and gas stripping package).
- Access to shared potable water facilities.
- Bunkered potable water: logistics can be challenging in winter months to get water tanks on board.

8 Salt Management Guideline: Production Operations

Detailed information from SNS operators has been used to inform this section. Operations activities as part of a salt management strategy can be summarised by the objectives:

- Maintain preventative measures.
- Restore declining or lost production.
- Monitor production.
- Record and reappraise procedures.

8.1 Salt removal and mitigation operations

Managing the risk and eventual occurrence of salt deposition in the well or flowline is addressed by two approaches: (a) Mitigation options to prevent or reduce the risk of salt deposition; and (b) Remedial options to remove salt build-up.

The key considerations with regards to salt removal and mitigations are discussed next, while Table 2 summarises the risks and challenges presented by the currently favoured mitigation and remedial measures.

1. Water injection into the production well or production flowline to reduce the salinity of the produced water and/or to dissolve salt deposits (water wash) is the most favoured mitigation and remediation method to address salt deposition [1-2]. The guideline recommends the following techniques based on established track records and published case studies:
   a) Bullhead water-wash.
   b) Free-fall batch wash.
   c) Coiled tubing wash.
   d) Capillary string with continuous water injection.

   The water wash principle is based on the high solubility of sodium chloride salt in fresh water (approximately 350,000 mg/L at ambient conditions). Water washes are used to dissolve existing salt deposits in the well and as a mitigation activity by performing them at a regular interval when the well's production is in decline. Case studies confirm SNS operators are comfortable with water washes and these are executed as a matter of course where required.

Operator preferences to perform water washes include:

- Timing wash water treatments at the right point in the well's production decline profile.
- Regular wash water treatments at fixed intervals.
- Automated (from shore) and manual (on location) are both in practice.

Wash water can include *foaming agent* for improved lift or halite inhibitor for enhanced performance (subject to a positive outcome from a field trial).

Wash water squeeze: Over-displacement of wash water into the formation can be used to dissolve salt deposits in the near wellbore region of the reservoir.

Table 2: Factors influencing was water application

Water injection option	Mitigation or remediation	Equipment	Advantages	Risks and challenges
Bullhead	Remediation	High pump capacity required.	Relatively easy and effective if the offshore facility has the infrastructure in place. Reach reservoir, treat long horizontals and potentially squeeze the formation. Subsurface tie-backs can be treated by intervention vessel.	Over displacement, unintentionally, of water into the formation: potential for reservoir damage and liquid loading.
Free-fall batch wash	Remediation	High pump capacity not necessarily required.	Can reach reservoir depth. Useful if the offshore facility does not have the pump capacity to bullhead	Inefficient removal of salt, especially in long horizontals. Liquid loading.
Coiled tubing wash	Remediation	Support vessel or platform-based. Through-tubing access.	All wells. Subsurface tie-backs treated from intervention vessel. Can reach reservoir depth and long horizontals. Good for deep, salt blockages. Well intervention can be used for data gathering: PLT, boroscope to support diagnostics.	Well intervention is required. Cannot be remotely operated, requires a programmed operation. Platform access can be restricted by deck space and crane hoist limit.
Capillary string	Mitigation	Capillary string, run with the well completion. Facility for continuous low rate water injection.	Platform wells and subsurface tie-backs. Can reach reservoir depth if through-packer capability selected. Multiple cap strings per well may also be an option to increase water delivery or add built-in redundancy.	Water injection rate is limited: therefore, this is mitigation rather than remediation. Cap string can be damaged during completion.

2. Other (non-water wash) techniques include:

a) Drawdown control.

b) Intermittent production (close in/open up well for cool-down/condensation).

c) Halite inhibitor usage.

d) Reperforation or hydraulic fracturing to bypass near wellbore impairment.

e) Water shut-off, zonal isolation.

3. Water injection into a gas well carries the risk of liquid loading and in tandem with the water wash activity is the requirement to understand the potential for liquid loading and for gas well deliquification (refer to Section 9.2). Wash water volumes in the well are often limited to 1 to 2 m3 to help with lifting the back-produced water and avoiding liquid loading. Use of foamer to aid lift is frequently implemented.

4. Wash water injection into a gas well/flowline requires wash water salinity and quality issues to be addressed. In principle, seawater with approximately 30,000 mg/L salt content can dissolve salt but the take-up will be limited to a relatively small percentage mass. Operators favour fresh water for increased dissolution power while using smaller water volumes. A low salinity option can be considered where there is provision for desalination of seawater, by, for example, reverse osmosis membrane technology.

5. *Wash water supply* for salt management may be drawn from various sources; this requires all or some of the following, together with a commitment for ongoing monitoring and maintenance:

   - A reverse osmosis package can be used for fresh (or low salinity) water from seawater.
   - Corrosion control through removal of oxygen (down to 10 ppb): options include vacuum deaeration or gas stripping. Injection of oxygen scavenger provides the additional means to achieve the target oxygen level. Oxygen scavenger is unlikely to be effective alone, without deaeration, on fully oxygenated source water.
   - Biocide treatment: periodic batch bmbiociding of the wash water system; fouling of the capillary string during continuous wash-water injection might require capacity to add biocide or inject a batch biocide treatment into the capillary string.
   - Hydrate inhibition: some methanol or MEG content most probably will be required (See Section 9.3).
   - Foam water treatments: addition of a foaming agent (surfactant) to improve lift.
   - Wash-water injection pumps: for bull-heading or multiple capillary strings ideally independent, dedicated pumps should be in place.

6. Requirements for oxygen removal: Large volumes of wash water frequently used, will introduce an additional corrosion risk associated with dissolved oxygen. Oxygen levels should be consistently brought down to an acceptable target: 10 ppb residual oxygen in water is usually cited as the maximum tolerated level for seawater injection systems with carbon steel vessels and piping). This is normally achieved with a combination of deaeration and addition of oxygen scavenger. Operator experience will be a key determining factor here as often the incremental corrosion risk can be offset by other factors such as the volume and frequency of wash water and by reducing the time-exposure of tubulars to the treatment. However, corrosion resistant alloys such at 13Cr steel can be prone to cracking and this is a catastrophic rather than an incremental failure: it is necessary to undertake a corrosion risk assessment before commencing routine water washes and, for new developments to follow stringent materials selection procedures.

   Routine wash water systems should be provided with an in-line oxygen monitor ('*Orbisphere'* or similar equipment) to provide a continuous assessment of wash water quality when the operation is underway.

7. *Formation damage induced by injected water*: Brine salinity can impact the stability of clays and silts within the formation [16]. For this reason, the selection of a low salinity (or potable) wash water may not be an option if water is to contact a water-sensitive formation. Core flood tests may be required before application, or prior knowledge may support adding KCl or commercial clay stabilisers to the wash water.

8. *Wash water treatment example*: An example of a programme for free-fall batch water-wash with fresh water is given here. The small volumes lend the procedure to remotely conducted water washes for pre-emptive treatment:

   - 400 litre batch free-fall wash.
   - 12-hour soak.
   - 4-hour flowback.
   - 400 litre batch free-fall wash.
   - 12-hour soak.
   - Bring well back online at small choke (40%) for one day.

9. *Water wash operations in long horizontal intervals:* Understanding the flow regime in long horizontal sections is necessary to improve the injection (diversion) of wash water along the full length of the interval and to avoid liquid loading. This presents a challenge in wash water treatments, similar to that presented by other well treatments in horizontal intervals, such as acid stimulations and scale squeezes:

   - Bull-heading at high rate may give improved diversion along the length of the interval (a rule of thumb suggests pump rates should be in excess of 3 bbl/min). Squeeze modelling software will help ascertain optimum pump rates.
   - Foamed fluids can help with diversion and lift. Use of foamer to help with lifting the well after treatment is becoming an integral part of wash water operations in SNS assets. Foamer is added to the wash water during bullheading.
   - Coiled tubing presents the surest way of contacting the full length of the horizontal interval. Coiled tubing units require space on deck and hoist lift unless operation is conducted from a support vessel.

10. Hydrate inhibition may be required during wash-water treatments or stepped up, if already in place. Caution is required here as methanol is known to trigger salt deposition from high salinity brines (see Section 9.3).

11. There may be a *diminishing impact* of successive water washes – cases are known where it became increasingly challenging to restore production when the salt plug extended over a significant part of the perforations.

12. *Well management and drawdown control*: In this context, drawdown control means choking back the well to reduce drawdown; the aim here is to bring the pressure drop from formation to wellbore to within the no-risk part of the halite envelope. This can be achieved by a downhole choke, if included in the completion, or by the production choke at the tree.

    Drawdown control can be considered a viable method of salt management if the halite model is robust, well flow rates are within the Turner limit to avoid liquid loading and the reduced gas delivery is acceptable. Operators may choose to operate outside the drawdown limit by implementing a water-wash programme.

    For older assets, reducing the pressure drop across the wellbore will not be an option where chokes are not in place or worn and no longer functioning.

13. *Halite inhibitor usage*: Options for halite inhibitor usage include:

    – Halite inhibitor added to wash water.
    – Halite inhibitor squeezes into the reservoir [10] with or without foamer.
    – Continuous halite inhibitor injection via capillary string.

    Most operator experience of inhibitor usage to date indicates a preference for adding halite inhibitor to wash water for either bullhead or continuous capillary string injection, as a means of enhancing the water wash. Injection of the chemical alone has not yet found common usage, but it continues to be an active area of laboratory research [8, 10, 12].

14. *Water shut-off and zonal isolation*: Water shut-off designs need to be supported by a reliable PLT survey and, for cased hole, a CBL showing good cement bond over a substantial length of casing/liner. Mechanical water shut-off options include: bridge plug, straddle. Success in reducing water influx is limited and short-lived. Chemical water shut-off, for example, using methods based on pumping silica solutions, is generally not successful in gas wells.

15. Other salt mitigation/remedial methods included here are:

    – Reperforation, to bypass blocked perforations or formation damage.
    – Hydraulic fracturing, to reduce drawdown.

    Major interventions of the type mentioned are performed by SNS operators but are not commonplace. Use of these methods should follow rigorous diagnostic and investigative attempts to identify the cause of poor well inflow and define a clear objective for the intervention: there may be other well performance issues to address other than the possibility of salt deposition. If salt is suspected, water wash options, including squeeze treatments, offer the potential of lower risk and better payback and should be considered first.

8.2 Production monitoring, surveillance and diagnostics

1. Relevant production monitoring activities for salt management should be fit-for-purpose and aim to address uncertainty. Data gathering is challenging bearing in mind the typical production constraints faced by SNS assets, including shared facilities, normally unmanned facilities, commingled production, low water-cut measurements, etc.

2. Routine *production monitoring* should aim to encompass:

   - Well production performance: wellhead temperature and pressure, flow rates.
   - Downhole conditions if bottom-hole gauges are in place.
   - WGR and water-cut.
   - Produced water salinity and trended ion ratios [5], (Figure A1, Appendix A).
   - Salinity of the recovered hydrate inhibitor (methanol or MEG) and TEG in the dehydration system.
   - Wash water and treatment chemicals quality and availability, for mitigation and remedial activities.

   Table 3 lists the ranges of WGR and reservoir pressure that are understood to influence whether the well will have a salt-related problem or not. The ranges quoted in the table are from shared SNS field experience and are indicative, providing only a broad estimate of where salt problems may occur. There are many recorded instances of wells outside of these ranges with salt problems.

Table 3: Impacts of WGR and reservoir pressure on the potential for salt precipitation

WGR or reservoir pressure	Range (Units 1)	Range (Units 2)	Salt-related problem
WGR	Above 50 m^3/ $MMSm^3$	Above 9 bbl/MMscf	Unlikely
WGR	30 to 50 m^3/ $MMSm^3$	5 to 9 bbl/MMscf	Possible
WGR	Below 30 m^3/ $MMSm^3$	Below 5 bbl/MMscf	Likely
Reservoir pressure	Below 150 bar	Below 2175 psi	Possible

3. *Non-routine surveillance* will include well intervention data gathering:

   - Wireline HUD and bailer runs to determine salt build-up and retrieve solids samples when the well requires entry.
   - Production logging (PLT) survey.
   - Downhole camera surveys.
   - Fluids (and solids) sampling and analysis.

4. Well production monitoring: Operators identify characteristics in the daily telemetry production profile as well performance declines; ultimately the decline can be accompanied

by with on/off periods lasting days. A common feature is the saw-tooth behaviour pattern indicating downhole salt precipitation (Figure 10). The decline curve can be used to indicate the optimum point to perform a water wash.

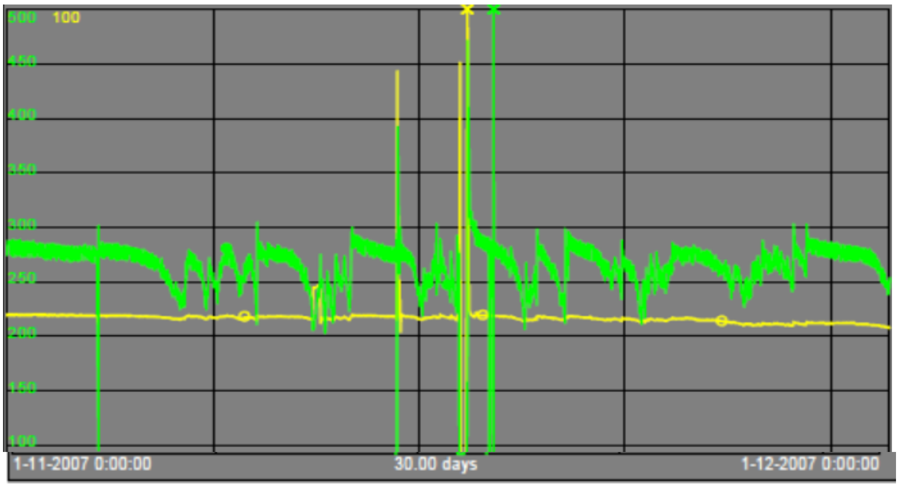

Figure 9: Typical saw-tooth production data indicative of downhole salt precipitation (2)

5. *Operators should endeavour to provide an estimate of the impact of salt deposition on a per well basis to support learnings*: Production loss can range from 5 to 50%. Where there is formation water breakthrough, it can reach 100%. Operators routinely factor in an estimated production deferment due to salt issues into monthly delivery volumes.

6. *Water-gas ratio*: Halite models are sensitive to small errors or changes in WGR, and this is difficult to measure accurately with shared flowlines and production separators; effort should be made to gather this data on a 'by difference' basis and supported by opportunities such a presented by staggered well start-ups after a shut-down. For land-based assets mobile test separators can be deployed.

7. *Produced water composition*: Fluid samples should be taken and laboratory-tested as part of routine production monitoring. Ion composition and ion ratio data should be trended. Key composition ion ratios can be identified for tracking [5] (see the indicative water composition examples in Figure A1, Appendix A). ion ratio trends can be timely indications of formation water influx and salt drop-out.

8. *Formation water breakthrough*: Some operators have reported that on sudden formation water influx, such as with water breakthrough via natural fractures or hydraulic fractures connecting with formation water, zonal isolation breaking down leads rapidly to a large salt plug in the lower section of the completion/well. This may not be an evaporation effect because the water content is too high. The temperature at the bottom of the well should be close to reservoir temperature so cooling would not be expected. A possible mechanism may involve cool-down in the wellbore when the well is liquid-loaded, which together with salt precipitation in the upper tubing closer to surface could result in salt solids falling back downhole when production ceases.

9. *TEG (glycol) contactor*: Carry-over of salt will impact the salinity of the glycol dehydration system. For at least one SNS operator, this has resulted in the need to change out glycol on a monthly basis.

10. *Well interventions*: Halite model updates are helped by a commitment to run wireline HUD and bailer when wells are entered. This should be built into every well entry programme. Apart from integrity issues, interventions usually target wells with declining production which could be salt-related.

11. *Cement bond log*: Where possible at the completion stage or during a well intervention, a CBL should be run to confirm the quality of the cementation behind production casing and liner; this is fundamental for informing future water-shut off choices.

12. *A PLT survey* should be considered when a well intervention opportunity permits, to show inflow especially in long horizontals and low points in the interval which may allow water to accumulate.

8.3 Salt management operations – supporting narrative

8.3.1 Preferred treatment

Most SNS operators have indicated that water washes are the preferred treatment for salt management and treatments are applied on a routine basis. As a result, water washes are common and an integral part of the operation of many SNS wells. In many cases, the operations are remotely controlled from the onshore control room; for others water washes are applied manually from platforms and NUIs. In new developments in the areas where salt problems are expected, water wash systems are built in at the design stage. In this way CAPEX and OPEX are well-defined from the outset and ongoing OPEX costs are thus considered to be effectively managed.

Since the 1990's, SNS operators have progressed along their own learning curves: early water washes took place with varying degrees of success, but now with water washes either manually or remotely pumped, the operation is considered routine. A successful water wash is expected to:

- Restore the gas production profile back to expected levels or ideally higher.
- Increase well uptime, reduce lost production days and where possible, extend the time between treatments.

Water washes may be used to dissolve existing salt deposits in the well or as a mitigation activity by performing the water wash at a regular interval when the well's production is in decline.

One large operator conducts approximately 600 water soak treatments on a yearly basis. Operations in the hundreds per year appear to be typical for the larger SNS operators.

Wash water treatments on the same well can take place at intervals of every few days to every few weeks depending on the severity of the problem. The timing of the washes is related to well performance (rate, wellhead – and downhole if available – pressure and temperature conditions).

Wash water operations are carried out by the asset operators themselves: there is seldom any third-party service provider involvement. This suggests the water washing is regarded as a low-resource, cost-effective operation that is built-in to routine operations.

Monitoring well performance for programming water washes is critical to success: failure to wash routinely at the optimum point in the cycle has resulted in the loss of production on a few occasions. For this reason, designing and installing remotely operable facilities has allowed for more frequent washing and improved performance.

For highly deviated/horizontal wells, bull-head or free-fall water washes will not effectively reach all perforations and coiled tubing would be an alternative. However, for many SNS operators, the justification and business case for a coiled tubing wash and considering the risks and uncertainties is challenging.

Managing key performance wells may result in a variety of mitigations. One operator reports that a high rate producer is being choked back to manage the salt risk. Pre-emptive water washes were undertaken on this well monthly aligned with platform manning dates to maintain deliverability. The confirmation that salt is the problem and that water washes provide the solution has led to the retro-fitting of a capillary string in the well for continuous injection.

1. Liquid loading risk

The liquid loading risk is managed by the application of foam in the wash water treatment recipe. In many cases, addressing liquid loading by installing velocity strings is too costly for offshore operations. Therefore, many operators inject foam to limit liquid loading problems. Foamer addition has also been shown to lift sand and solids out of the wells. For some cases, liquid loading concerns are addressed by optimising the volumes pumped based on bottom-hole pressures.

2. Velocity strings

For improved lift of water-loaded wells, velocity strings should be an option when investigations indicate that salt problems are not the underlying cause of water loading. The velocity string enables liquid lift at lower drawdown.

3. Drawdown control

For many operations with older assets and facilities, the only mitigation option other than water washing, is to reduce drawdown by choking back wells to operate at higher WHPs. There is no CAPEX associated with this, but it results in deferred production where productivity indices (PI) suggest wells can produce at higher rates.

4. Water shut-off

Water shut-off by mechanical means (such as setting bridge plugs or straddles) has been tried but the success rate is low; SNS experience suggests any benefit of low water-cut is limited to no more than one year.

8.3.2 Wash water operations

Generally, operators have been successful in managing salt problems by water washes. As such most lost production is related to not being able to reinstate wells in late field life and around the liquid unloading rate being compromised. Some reported fields have suffered severely from salt deposition that without water washes, wells would have ceased to produce within one to two years after start-up.

For some wells a misdiagnosis of liquid loading has been tested by bull-heading wash water into the formation. Wells responded positively with sustained production over a longer uptime period. In these cases, salt deposition in the near wellbore region of the formation reduced the PI below the Turner critical rate contributing to liquid loading; removal of the salt deposit restored the full PI and allowed the well to lift.

1. **Chemical additives for wash water**

   Wash water treatments have shown improved performance and success with the inclusion of all or some of:

- Oxygen scavenger and ascorbic acid to complex iron.
- Foaming agent.
- Biocide.
- Hydrate inhibitor (methanol or MEG).
- Halite inhibitor.

Oxygen control (see Section 8.1) is important for minimising corrosion risks, biocide to prevent fouling and methanol or MEG to avoid hydrate formation. Trialling of foamer and halite inhibitor to enhance wash water performance should use any relevant laboratory test data and be approached initially on a well-by-well basis to determine what works. Inclusion of a film-forming corrosion inhibitor in the wash water (for carbon steel completions) may not be appropriate if the wash water is likely to enter the formation, as film-forming corrosion inhibitors may adversely affect rock wettability. There is also the potential for negative effects if corrosion inhibitor contacts a salt plug in the wellbore where the chemical can separate out onto the surface of the salt, forming a protective layer that is resistant to water. One operator tried to address this with mutual solvent pre-flushes ahead of the wash water but with little benefit.

2. **Halite inhibitor**

Shell has reported testing of halite inhibitor products that inhibit crystal structure growth. Tests required the application of several thousand ppm of the inhibitor in 2.5 m3 wash water; the result was reported to give a less erratic post-wash production performance [10]. Precipitation inhibitors, which require pumping the treatment fluid into the near-wellbore region of the reservoir, enable the halite inhibitor to adsorb, which should offer the prospect of longevity of treatment.

For bull-heading operations, some operators are routinely adding halite inhibitor to the wash water mix because of growing evidence that the inhibitor enhances the treatment.

8.3.3 Wash water composition, volume and frequency

Operator experience notes a seemingly wide variety of wash water treatment procedures but there is an underlying commonality in the way problem wells are addressed, as shown in the following four examples:

- *Operator 1*: Water washes of 1-3 m^3, every 3 to 4 days.
- *Operator 2:* Wash water applied on average every six days to problem wells, using 4 m^3 water, soak for 1 hour then produce on low choke for 30 minutes.
- *Operator 3:* Daily water washes of 1 m^3 over a period of 5 days. Wash water volumes are kept conservatively low to ensure lift. In some cases, it was advantageous to allow water to trickle down the low side of the tubing.
- *Operator 4:* Periodic wash water squeezes for fractured reservoirs: treatment comprising 5 m^3 to 10 m^3 foamed wash water over-displaced into the fractures.

A typical wash water composition tends to include the following:

- Fresh water with added 2-7% KCl to minimise the risk of clay swelling in the formation.
- Foamer surfactant: 5,000 to 25,000 ppm, depending on the chemistry of the surfactant.
- Iron complexing agent: 500 ppm ascorbic acid before pumping (for iron complexing, pH adjusted to about 4.5, also has oxygen scavenging action).
- Scale inhibitor or dilute acid: option for wells at risk of carbonate or sulphate scale (if there is sulphate in the system).
- Additional additives: such as mutual solvent (EGBE or DEGBE), clay stabiliser, depending on results of laboratory tests or reservoir formation requirements.
- Gas: optional, for establishing foaming in the tubing.

Water wash frequency

Current practice for deciding when to perform a bull-head water wash is reliant on well production monitoring and the type of telemetry data shown in Figure 10. Here the decision on when in the cycle to start a water wash is largely ‘trial and error’ but close monitoring of the well’s response provides immediate feedback and allows for optimisation of the timing and confidence in the outcome to the point that with the right infrastructure in place the water wash can be automated.

Further refinements are underway: for example, TNO are developing their halite model (Section 11.4) to include a water-wash optimisation module, undergoing field trials in 2019 with selected North Sea operators.

8.3.4 Continuous water injection via capillary string

For continuous water injection via capillary string directly into the well, a typical wash water composition can be:

- Source water: treated potable water.
- 2 to 10% foamer.

- Additional ppm corrosion inhibitor for carbon steel completions: added as top-up, subject to oxygen control requirements and on the understanding the wash water will not contact the formation or a salt blockage.

The use of capillary strings for continuous downhole injection of wash water is a relatively recent development that shows promise [11, 19]; it is too early to conclude on the medium to long-term benefit and whether sufficient water can be injected on a continuous basis to be effective at later stages in the asset lifecycle without the need to revert to bullhead water washes.

8.4 Production monitoring – supporting narrative

Relevant production data and monitoring techniques that provide an indication of a salt problem are:

- Production decline.
- WGR increasing.
- Water composition data from samples, showing changing ionic content.
- Failure of valves to function-test.
- Intermittent production (can be indication of salt bridge).

The WGR is critical to understanding and predicting the onset of salt problems: it is a primary input into the halite model. WGR is difficult to measure accurately in early field life when water-cuts are very low, and this becomes more complicated with shared flowlines and shared production separators. Additional test separators are usually difficult to justify. There should be access to mobile test separators for land-based assets. It is a common observation that although no water production is measured in the production system, severe salt problems can still occur.

For shared facilities without a test separator, a minimum requirement will be for the total field water production volume and water salinity to be recorded continuously where volumes allow and allocated to the wells.

Some operators monitor by difference when flow-testing individual wells and this incurs errors in individual well production data that in many cases have to be tolerated. For most SNS wells there are no continuous bottom-hole data, and for many older wells no wellhead data, therefore, salt management interventions are triggered usually after the event when the loss of production from one well can be seen in the total production.

In spite of challenges, there are many examples of improvements in good practice; for example, having the capability to test wells on at least a quarterly basis and sampling well fluids on a six-monthly basis or if there is a significant change in well performance.

For one operator on a relatively new asset, a key high-rate producer had to be choked back as mitigation. A programme of pre-emptive water washes was undertaken on the well monthly aligned with platform manning dates to maintain deliverability. Because of the high status of this well the operator decided to install a capillary string in the well for continuous wash water injection.

Most commonly, the pressure vs. rate (or tubing head temperature) trend is the indicator of performance loss and potential salt problems. Likewise, an increase in pressure drop over the choke (at same settings) is an indicator. Salt problems are sometimes also identified by irregular well performance, for example an irregular rate with fixed settings – even minor irregularities can be indicative. Observations are supported when performance is reinstated after water washes.

For some operations, downhole temperature sensors are installed in key wells: often this comes with mixed results, as the output can be difficult to interpret in terms of showing changes due to water flow and the effect of JT cooling.

Production monitoring and halite model updates are supported by a commitment to run wireline HUD and bailer when wells are entered (built into every well entry programme). Apart from integrity issues, interventions usually target declining production which could be due to salt or liquid loading or both and where foam lift might not help; in this case the reward could be restored production.

In view of the fact that most production monitoring will have to work with inaccurate measurables, a range of water composition data and a risk-based approach, the satisfactory outcome will usually be to adopt a conservative margin when applying salt management. For example, wash water injection requirements might aim to cover a range between 10 to 20 bbl per well and pump capacities, piping and chemicals will need to reflect this.

9 Salt Deposition Effects and Impacts: Case Studies

Most salt deposition events in SNS gas wells occur downhole and the impact is a steady decline in production. In some cases, salt solids are carried to surface (via mechanisms discussed in Section 11) and salt blockages are found in SSSVs, chokes, HIPPS and instrumental devices. As mentioned earlier, carry-over of salt can affect the salinity of the glycol dehydration system. For one location, this has resulted in the need to change out glycol monthly.

Field evidence and shared anecdotal experience suggest that wells that are vulnerable for salt deposition can be identified by all or some of the following:

- Low WGRs (less than 30 m^3/million Sm^3).
- Wells with low reservoir pressure (below 100 bar).
- Wells operating at high drawdown.
- Produced water composition showing a trend towards high, saturated, TDS or changing trend in salinity over a relatively short period (weeks).
- Wells on intermittent production (recovery of production after a short shut-in).
- Reduced gas export.
- Sub-surface safety valves failing function-tests.
- Wells exhibiting slugging.

Figure 11 summarises water wash success factors according to treatment method. This is a snapshot, current up to 2018 and based on operator's data submitted to the EBN and OGA databases.

Success Factors by Treatment Method

• *Batch water-wash, by bull-heading*	*90%*
• *Batch water-wash, by free-fall*	*68%*
• *Coiled tubing water wash*	*59%*

Figure 10: Reported success factors for water washing depending on treatment method (2)

Production losses can range from 5 to 50%, with complete well failure a possibility on formation water breakthrough. The number of wells affected varies between 5 to 25% of an asset's well stock. There are cases where initial production suffered severely from salt that without water washes, the field would have ceased to produce within one to two years from start-up.

SNS operators tend to agree that assets are now reasonably successful in managing salt problems, largely by water washes. The critical period tends to be early field life, where salt-sensitive parameters are not well-defined.

Salt management requires significant chemistry input within the operations team. Many operators use a multi-disciplinary approach supporting the chemistry effort with subsurface, production and process expertise.

The over-arching philosophy for many companies is that the Southern North Sea basin is best characterised as late-life field management and the aim is to keep wells on production for as much as possible with full attention paid to operating costs. In this respect activities have been successful, with some operators reporting up to 90% recovery.

9.1 Operational constraints and resourcing

The salt risk is now considered to be a known problem for SNS operations, therefore remedial action is expected and factored into OPEX costs. Typical production constraints and challenges that impact salt management in gas assets are often associated with normally unmanned facilities, commingled production, low water-cut measurements, shared facilities such as flowlines, pipelines and service lines. (e.g., inhibitor, wash water).

Offshore SNS activities are constrained by access to NUIs, due largely to limited working hours and no allowed overnight stays and the availability of intervention vessels. Difficulties are associated with conducting manual water washes or coiled tubing treatments at the required time in the well cycle, due to the lack of availability of an intervention vessel or fitting in with the schedule for visiting the NUI. At least one operator has secured access to an intervention vessel to ensure the optimum programme of water wash treatments across multiple assets can be undertaken.

Access to NUIs and platforms is also subject to the availability of the helicopter support services. Services can be changed depending on the provider’s business case: one operator reports helicopter landings being drastically reduced preventing them from visiting platforms as often as might be wished.

Shared facilities also mean that identification of problematic wells at risk of salt deposition is made more difficult due to commingled production in flowlines and topsides facilities. For example, the WGR is critical parameter in modelling the halite risk and monitoring the onset of a problem – but this is difficult to measure accurately with shared flowlines and production separators. Generally additional test separator provision is difficult to justify for existing facilities.

The evidence suggests that within a short time and because of a strong commitment to cooperate with other companies and share experience, the operator can define resource requirements for remedial water wash treatments with confidence, and washes can be planned on a routine basis inclusive of manpower and accessibility constraints.

Activities can be scheduled around NUI visits or aligned with manning rotas on a monthly basis, either for manually washing a well or to bunker water to allow remote facilities to continue functioning.

In contrast, land-based operations have less limitation in terms of accessibility for conducting remedial treatments. It is also possible to have use of mobile test separators: for this reason, well data on salt management from land-based operations is proving to be a good source for testing new models and optimising treatments.

9.2 Liquid loading and gas well deliquification

Thirty percent of gas fields in the Netherlands have some form of gas well deliquification measure in place [2]. Liquid loading issues are known to increase with depletion as water-cut increases and reservoir pressure declines and are not necessarily related to salt precipitation.

The mechanisms that are likely to lead to depletion-induced liquid loading are (Figure 12):

- Formation water breakthrough due to encroaching gas-water contact.
- Formation water transport to the near wellbore, via fractures or coning.
- Condensed water backflow down the production tubing.
- Water block near the wellbore following well shut-in.

Typical mitigation options are listed in Figure 12. In terms of diagnostics, the starting point is to evaluate the IPR/VLP correlation for liquid loading, using Prosper (or equivalent) vertical lift models to establish the Turner critical rate.

Liquid Loading Mitigation Options

- *Foam treatment: by continuous foamer injection or batch injection*
- *Velocity string or tail-pipe extension*
- *Other completion:*
  - *Eductor*
  - *Reperforation*
  - *Water shut-off*

Gas well deliquification measures are 70% successful

Figure 11: Liquid loading mitigation measures (2)

Distinguishing between liquid loading due to downhole salt deposition and liquid loading due to the mechanisms listed above, without a well entry, is seen as a challenge due mostly to the capacity to obtain and trend reliable production data. SNS operators are increasingly aware of the need to differentiate between liquid loading and salt deposition, and the monitoring procedures outlined in Section 8 provide a starting point.

In summary, the key differentiators are:

- Pressure behaviour on shut-in: for example, updating an IPR/VLP model (such as Prosper) might show the presence of 'skin' at the formation face or alternatively the Turner critical velocity condition is no longer being met.
- Downhole temperature changes (if downhole gauges are in place).
- Gas production rate showing the saw-tooth pattern and cyclic behaviour, indicating salt build-up.
- Changes in ion ratios in produced water [5]: if produced water ion data has been trended over time to provide a baseline then a drop in sodium ion with respect to other ions will indicate precipitation of salt at some point upstream.

9.3 Hydrate inhibition and impact on salt precipitation

Methanol, used as hydrate inhibitor, can trigger the deposition of salt and this is particularly a risk at subsea trees and in flowlines [13-15]. Figure 13 shows the effect on the halite prediction model of methanol triggering the precipitation of salt.

For SNS operators, shared provision of hydrate inhibitor between multiple assets will mean that an asset with a potential salt risk may not have the flexibility to avoid or reduce methanol injection when wells start producing highly saline formation water.

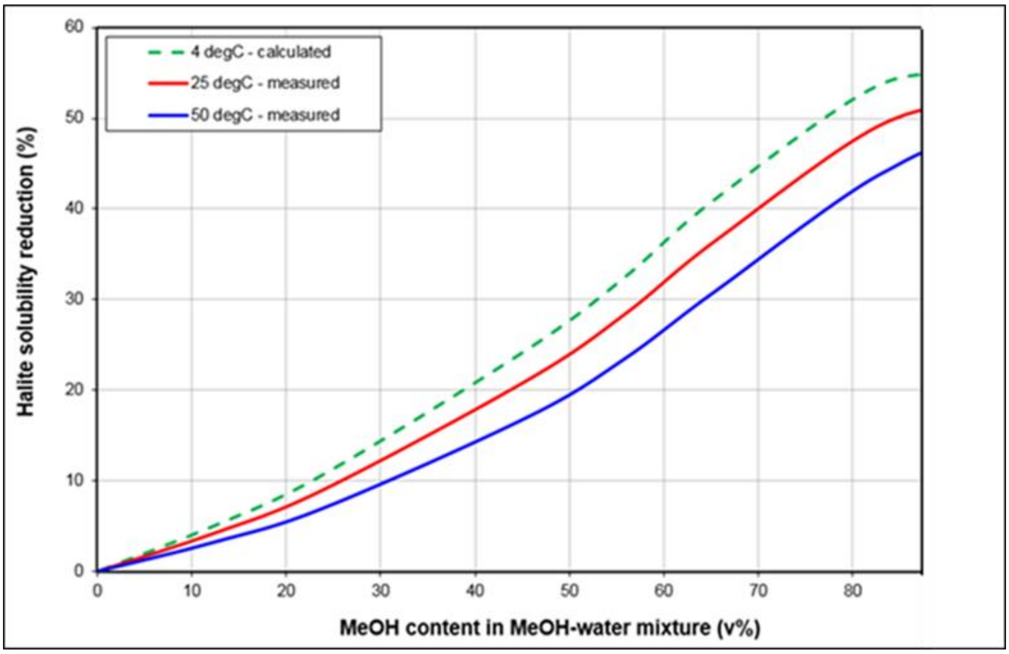

Figure 12: Impact of methanol on salt solubility in water at different temperatures (simulations by Lloyd's Register)

9.4 Other inorganic scale risks

Under certain conditions salt can co-precipitate with or be triggered by other inorganic scales such as calcite. For example, North Sea cases have been reported by Equinor (previously Statoil) [7, 9] in which wells experienced calcite scaling at bottom-hole conditions on water breakthrough, due to high drawdown and high temperature.

Figure 14 shows the simulated saturation indices for inorganic scales including salt (halite) for a North Sea formation water. The salt or scale risk is present at conditions below the relevant curve in the chart. This example suggests that calcite and barite precipitation may present as equivalent a downhole risk as halite. Here, the consequences of barite deposition in the well would be significantly greater than halite and water washing alone would not be enough.

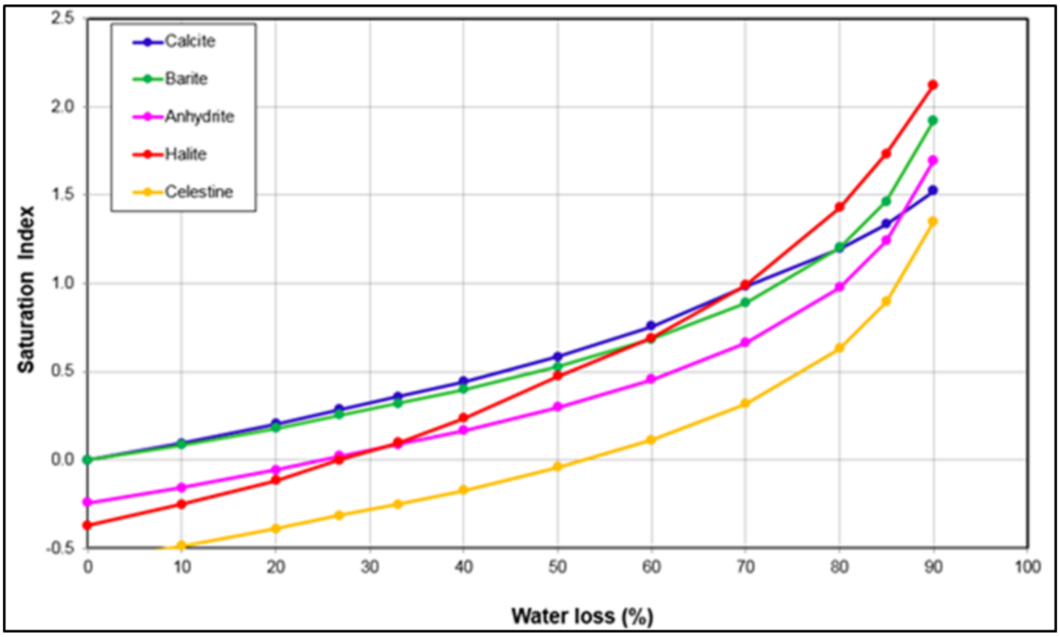

Figure 13: Salt risk envelope described in terms of saturation index and showing other scale risks (simulations by Lloyd's Register)

9.5 Condensate banking

Treatments to mitigate against salt deposition in the reservoir may create conditions favourable to condensate formation in the reservoir. Operator experience is based largely on defining the reservoir model to identify conditions that may promote condensate banking.

Except in late field life cases where the reservoir has dropped below the dewpoint, condensate dropout occurs in the near wellbore region of producing wells. The liquid hydrocarbon components condense in the near wellbore region and reduce gas permeability. Initially, liquid condensate forms as microscopic droplets in the smallest formation capillaries and will be held immobile by capillary forces. This initial condensate volume has little impact on gas permeability, since the capillaries have negligible influence on reservoir permeability. As pressure decreases liquid condensate volume may continue to increase and may reach a critical condensate saturation. Critical condensate (or oil) saturation occurs when the smallest capillaries have been fully saturated, and any additional liquid condensate begins to form and coalesce in the mid to large capillaries, important in permeability. Liquid saturation becomes mobile and further reduces gas permeability due to relative permeability effects (mutual inhibition). Mobile condensate is known as condensate banking.

Since the liquid volume is largely pressure dependent and the observed reservoir pressure varies as a function of distance from the wellbore, the liquid condensate volume varies with distance from the wellbore. Three zones may be established in such a scenario (depicted in Figure 15).

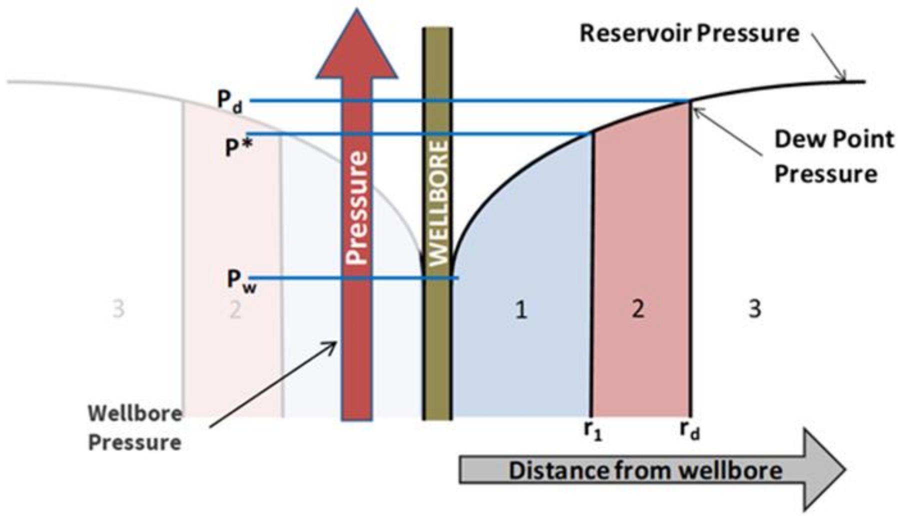

Figure 14: Schematic representation of condensate banking in the near wellbore region (diagram by Lloyd's Register)

- Zone 3 – deep reservoir, above the dewpoint (P_d) – single gas phase system.
- Zone 2 – below P_d but also below critical saturation with minimal impact on gas permeability.
- Zone 1 – below P_d and above critical saturation varying impact as a function of reservoir pressure (distance from wellbore).

Remediation of condensate banking (if possible) is very dependent upon the fluid phase behaviour, formation properties and fluid pressure. The majority of approaches attempt to limit drawdown pressure by some form of pressure support. This postpones the time for the reservoir to fall below the dewpoint (dependent on age of production and drawdown requirements).

Some alternative approaches include: re-pressurising the reservoir with water and/or gas injection, vaporising gas drive EOR, huff-and-puff (cyclic) production, use of methanol (or other chemical injection) to absorb water and condensate build-up around the wellbore. This latter case would have a negative impact on salt solubility leading to salt deposition in the near wellbore region.

10 The Salt Management Strategy Guideline

The Salt Management Strategy addresses the factors that support a sound business case for setting out a proactive way to help secure the full value of the gas asset; the strategy can form part of the Operator's Business Management System.

In line with the company's operational plans and procedures, a salt management strategy is expected to include:

- Strategy definition and execution plan.
- Allocation of resources.
- Monitoring and data analysis requirements.
- Mitigation and remediation provisions and actions.
- Assessment of success (cost, payback) and improvement.

An assessment of outcomes at the end of an initial production period would be useful to capture feedback on how production operations are working with the perceived or actual salting challenges, compared to the way the risk was estimated during the design stages of the new development.

It is important that case studies are documented and, where possible, made available in the public domain. There are opportunities for shared experiences to be discussed locally via special interest groups, for example, the focus groups moderated by EBN and OGA. Figure 16 gives an outline of the requirements of a successful salt management strategy. Neptune's Cygnus asset has been well-reported and provides an example of a good salt management strategy [19].

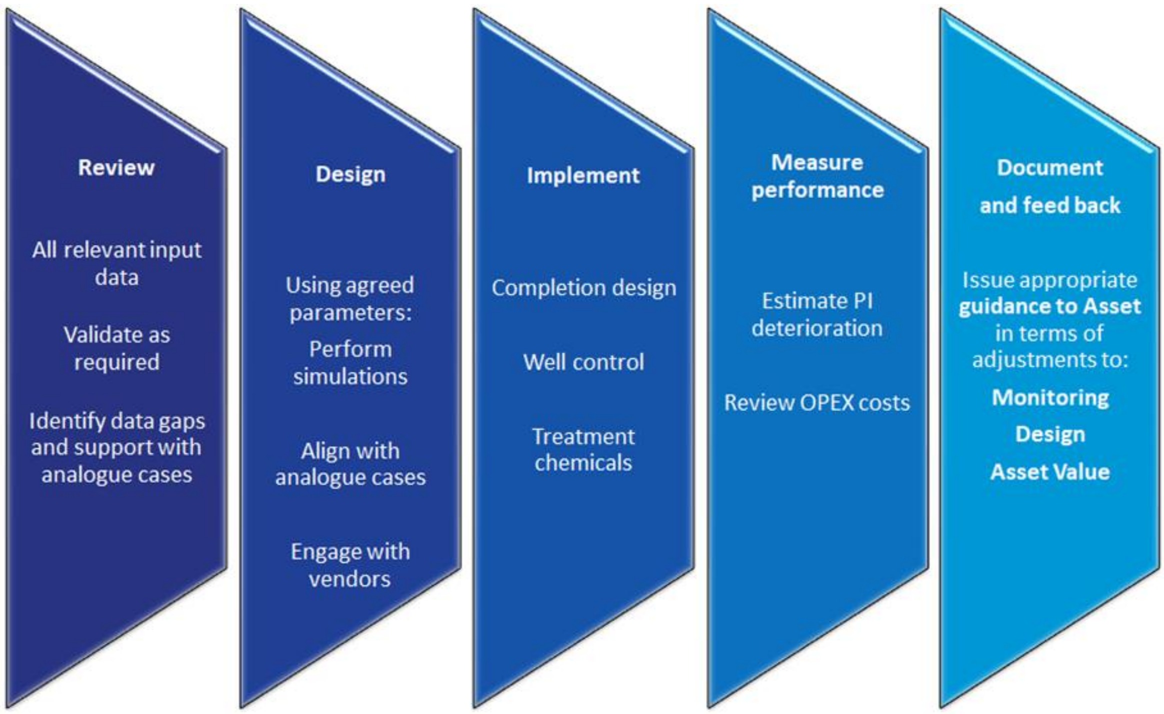

Figure 15: Component parts of a salt management strategy

11 The Physico-Chemical Aspects of Salt Precipitation

In the reservoir, gas will be saturated or nearly saturated with water vapour, when in contact with water at the gas-water contact. The saturation water vapour content is a function of pressure, temperature and salinity of the water. The temperature of the reservoir is approximately constant, as it represents a large thermal mass.

Figure 17 shows diagrammatically the salting mechanism. Near the wellbore a large pressure drop is present. The gas expands: at lower pressures, the gas now can in principle contain more water vapour. Due to the water vapour pressure difference between liquid water and gas stream, water starts evaporating. This leads to increased salt concentrations in the liquid. When a certain salt saturation level is exceeded, salt precipitation occurs. For NaCl this saturation level is slightly temperature and pressure-dependent. Salt precipitation leads to a reduced porosity and permeability of the matrix formation and hence gas production decreases.

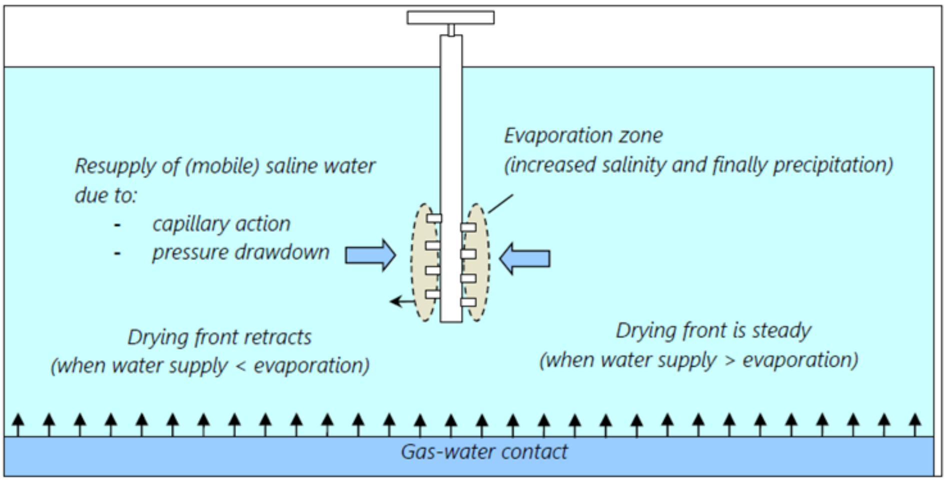

Figure 16: Salting mechanism in the reservoir/near wellbore region (diagram by TNO)

Water is replenished to the site of evaporation, mainly by two mechanisms: pressure drawdown and/or capillary action. The newly arriving saline water evaporates again, resulting in accumulated salt precipitation over time. Note that the transport of liquid water assumes mobile water being present. In contrast to liquid water, transport of water vapour via the condensation/evaporation mechanism is relatively slow and assumed negligible.

Salt precipitation can be described by the concept of a drying and transport balance. At the location of salt precipitation, the two process are equally strong [6]. Simulations show that this location is very sensitive to certain reservoir properties which makes accurate prediction difficult.

When the amount of evaporation is larger than the amount water transported to the evaporation site, a drying front retracts into the reservoir, leaving behind a moving front of precipitated salt.

When the evaporation rate is smaller than the amount water transported to the evaporation site, (saline) liquid water is produced at the perforations. Water produced at the perforations dries even more (with the risk of salt precipitation) and/or is transported downstream by the high velocity gas, along walls or lifted in the gas stream.

The mechanism of capillary action works in the following way: when water evaporates, a spatial gradient in liquid water content will build-up. By capillary action a transport of liquid water and of water vapour will start in the direction of flow of the water content. As the transport of water vapour is relatively slow, predominantly transport of liquid water takes place. Note that salt cannot be transported in the vapour phase (except when lifted in the form of salt particles/saline liquid particles) in the gas stream.

11.1 Impact of injecting water

When low salinity water is injected into the well, salt is – at least partly – dissolved and production can be reinstated at almost the same rate as before, depending on the extent of the water wash and circumstances. The water wash leads to a near-wellbore region impregnated with saline water (as a small 'water block'). This water – in principle – has to be displaced first, before gas production can restart. Hence, during fresh water injection, a part of the reservoir is subjected to water with a certain low, and by approximation constant salt concentration (at a certain pressure).

11.2 Long-term behaviour

Looking at larger time scales, the reservoir pressure drops slowly in time with production. As a result, the surrounding gas can contain more water vapour. Consequently, immobile (connate) water left behind and occupying a small fraction of the reservoir pore volume, will dry. Salt precipitation can take place in the smallest pores. As the amounts are small, the effect is limited in size, 'arrested' in place, and restricted to the smallest pores and not affecting large pores. The consequences for the near-wellbore by this mechanism will be marginal.

The implication is that impairment in the near-wellbore region, if it does occur, must be by some other mechanism. Possible explanations include:

1. The pressure-drop over time mobilises some previously immobile or connate water (i.e., water is pushed out of dead-end pores): this can be a source of saline water that can be transported towards the near wellbore.

2. Occasional transport of mobile water facilitates the alternating cycle of drying and wetting and exchange of mass, leading to an increase of salt concentration in the connate water volume and increased salinity of the mobile water.

11.3 Wellbore impacts

At the perforations and in the wellbore and production tubing an additional pressure drop takes place. Gas velocities are high enough to lift and fragment salt particles and liquid droplets produced at the perforations or drag them along the tubing wall. Part of the water will adhere to the walls. The produced water will dry further (at the wall or even in the gas stream), as the gas can contain more water vapour. Depending on circumstances this can lead to an accumulation of salt precipitation at, and in the neighbourhood of the perforations. Salt particles lifted in the gas stream or droplets of saline water will be transported further into the well and on their way can attach to surfaces. This is especially so in 'stagnant' zones, with low gas velocities (near walls, gas flowing from perforations into well), or where velocities change – particles can collect. Gravity forces become important in stagnant zones and due to the drying action, subsequent salt precipitation can take place

Higher up in the well, gas temperature and pressure fall. Water starts condensing from the gas stream (here the temperature effect on saturation is dominant). The condensed water is released in the form of salt-free droplets. The droplets mix with saline water/salt particles carried in the gas stream, and collect at tubing and pipe walls, where further mixing occurs with salt particles present on the wall.

Condensed water transported downwards by gravity from the top of the well, is subjected to a drying environment again and can be transported up again as water vapour in a cycle. It is also possible that some condensed water transported downwards can accumulate downhole.

Hence the transport/accumulation process of (saline) water, water vapour and salt in the well is quite different from that in the reservoir. To model this, it is possible to identify two sub-models (that in principle are coupled):

- Reservoir, near-wellbore and to the perforation interface.
- Perforation interface to well bottom-hole and to surface.

Additional description of the salting mechanism is available in published literature [4], [6].

11.4 Software commercial availability

There are several geochemical and chemical thermodynamic software packages currently available which calculate the scaling potential of minerals, under different conditions. These programmes usually calculate the equilibrium condition of the mineral from its ion composition. Some of them also include the reservoir properties. As the models are thermodynamic, the kinetics of precipitation and deposition are not accounted for and, for the well, the time scale and duration at a particular temperature-pressure point can often be so short that generally the equilibrium condition will not always be met.

Halite precipitation modelling requires close working with standard oil industry software simulators. For the estimation of reservoir pressure and temperatures and fluid conditions, industry standard simulators ECLIPSE, MoReS or OPM are used. Steady state and transient multi-phase flow simulators such as PIPESIM, OLGA or Ledaflow are used for establishing flow conditions in the well and pipeline.

Specialist geochemical packages with a published track record in modelling halite are available: these include:

- OLI ScaleChem with Stream Analyser: from *OLI Systems Inc*. (see www.olisystems.com).
- TNO Dumux, Saltmux: TNO's advanced models for halite precipitation under flow conditions.
- Solmineq: developed by Lloyd's Register, originating from University of Calgary in the 1990s.

- TOUGHREACT and EWASG module: originally developed by Lawrence Berkeley Laboratory in the 1980s (see www.tough.lbl.gov).

Saltmux is a software tool developed by TNO with the support of multiple oil industry operators through joint industry projects during 2013 to 2019. The software tool simulates the salt precipitation and deposition in the near-well bore region of gas wells. It is built on the open source software DuMu^x from the University of Stuttgard (a description of the DuMu^x application is provided on the website, www.dumux.org).

Further to the multi-phase flow in porous media, additional functionality has been developed such as:

- Brine-methane fluid system.
- Vapour pressure reduction due to salt content.
- Allowing tabular data representation for material laws.
- Allowing film flow below the apparent irreducible liquid saturation.
- Capillary pressure regularisation below the irreducible liquid saturation.
- Capillary pressure correction.

The model has been validated with production data and used in optimisation studies [6].

11.5 The halite precipitation envelope

Geochemical software packages, as mentioned, calculate the scaling potential of each mineral likely to be relevant to formation water chemistry. The simulation derives the thermodynamic equilibrium condition of the mineral at a defined pressure and temperature operating point with respect to its ions in aqueous solution.

Geochemical models are widely used to compute the thermodynamic scaling tendency in terms of the saturation index (SI), which, using calcite ($CaCO_3$) as an example, is defined as follows:

$$SI = \log\left(\frac{a_{Ca^{2+}} a_{CO_3^{2-}}}{K_{sp\,(CaCO\,3)}}\right)$$

where $a_{Ca^{2+}}$ and $a_{CO_3^{2-}}$ are the activity coefficients of Ca^{2+} and CO_3^{2-} ions and K_{sp} is the solubility product of calcium carbonate. Similar indices are derived for sulphate scales.

If SI > 0, water is supersaturated with scaling ions and hence scaling is thermodynamically possible; however, if SI $\leqslant$ 0, water is at or below saturation with respect to a given scale and scaling cannot occur. In reality, the scale may not form even though the saturation index is positive. Additional energy is required to form scale nuclei and to transfer the scale forming ions from the bulk solution to tubing or pipeline surfaces; this is represented by the *critical saturation index* which is specific to each scale type. If the saturation index of the scale examined is above a critical value, then scale deposition would be expected.

Key input data for evaluating the risk of scaling are:

- Formation water or produced water composition.

- Reservoir temperature and pressure.
- Hydrocarbon fluid composition and bubble point pressure.
- CO_2 concentration in reservoir gas (and lift gas if applicable).
- Gas to oil ratio.
- Water-cut (and injection water composition if applicable).
- Identification of system nodes with significant pressure, temperature or pH changes.

The salt solubility in water at a given temperature and pressure is calculated using the geochemical model software. The tendency for the produced fluids to experience water evaporation (or water loss) and condensation (water gain) during production is determined from the change in water content in the gas and the WGR. The following equations [5] are used to determine water loss: a positive water loss (WL) indicates water evaporation and negative one, water condensation.

$$WL\ (v\%) = \frac{W_{P_iT_i} - W_{P_rT_r}}{FWGR.F_W} \times 100 \qquad (2)$$

$$F_W = d\text{-}TDS/1000000 \qquad (3)$$

where W_{PT} is water content in gas at a selected PT condition, FWGR is the formation water to gas ratio, FW is the pure water fraction in formation water, d is water density in g/cm^3, while the subscripts *i* and *r* denote any given location and the reservoir, respectively. The same unit should be used for the calculated water content in the gas and FWGR, e.g., stb/MMscf. Therefore, a conversion factor, F_W, is included in Equation 2.

Two types of salt risk envelopes can be generated:

- A series of envelopes at a fixed temperature, showing the maximum pressure drawdown for different reservoir pressures and FWGRs;
- A series of pressure-temperature curves at a fixed reservoir pressure, for different temperatures and WGRs.

Each set of envelopes can be applied to wells with a similar reservoir temperature, gas and formation water compositions. If an operating condition is inside the envelope, salt deposition is expected. The further a pressure-temperature point is from the envelope boundary, the higher the driving force to deposit salt.

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Appendices

A Formation Water Composition from SNS Basin

The principal producing reservoirs in the Southern North Sea basin are:

- Rotliegend
- Carboniferous
- Zechstein
- Bunter
- Platten

Typical formation water compositions from the basin are shown in Table A.1:

Table A.1: Examples of southern North Sea formation water compositions (indicative data by Lloyd's Register).

Ion / property	Formation water composition (mg/l)	
	Example 1	*Example 2*
Sodium Na^{+}	76,442	68,495
Potassium K^{+}	1,234	1,231
Magnesium Mg^{2+}	3,900	3,594
Calcium Ca^{2+}	23,288	20,700
Strontium Sr^{2+}	949	907
Barium Ba^{2+}	12	13
Dissolved iron Fe^{2+}	204	206
Chloride Cl^{-}	172,243	154,477
Bromide Br^{-}	0	0
Sulphate SO_4^{2-}	162	155
Bicarbonate HCO_3^{-}	438	456
Volatile fatty acids (as acetate)	23	23

Ion / property	Formation water composition (mg/l)	
	Example 1	*Example 2*
Boron B^{3+}	38	38
Total dissolved solids (TDS)	278,955	250,317
TDS (ppm)	*234,038*	*213,542*
Density (g/cm^3)	*1.19*	*1.17*

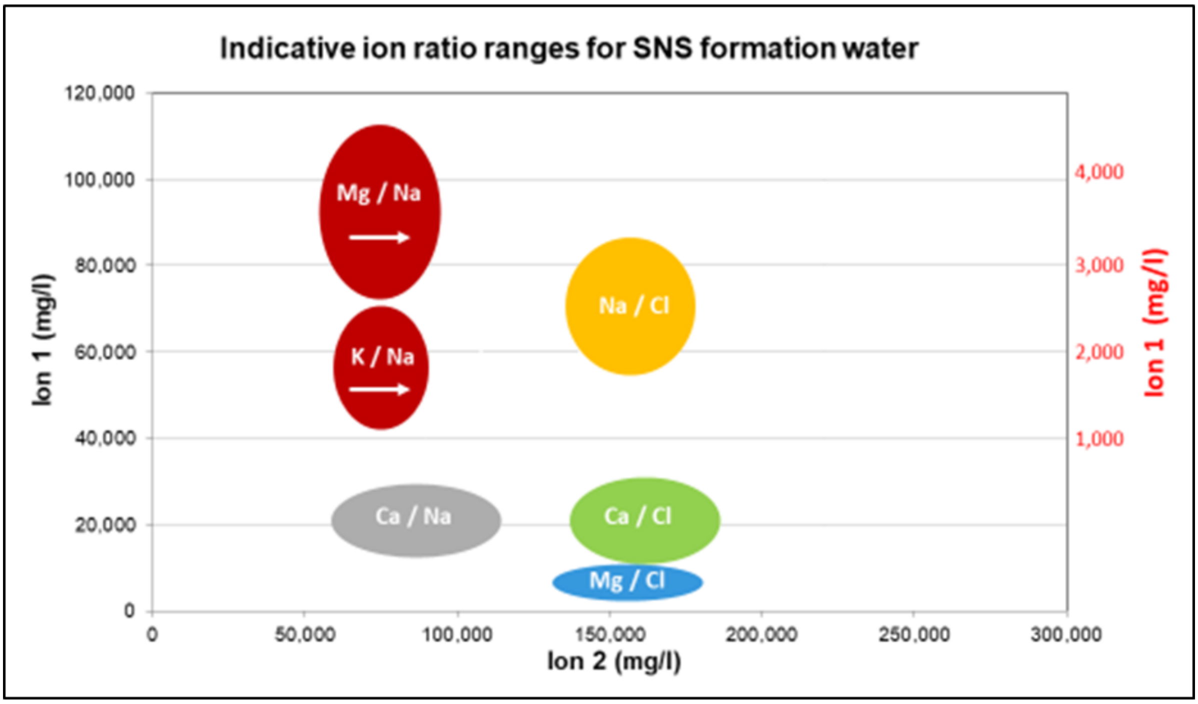

Figure A1: Indicative ion ratio ranges of Southern North Sea formation water compositions (compiled by Lloyd's Register).

(Arrow refers to right-axis, otherwise read from left-axis).

B Water Saturation of Methane

The maximum (saturated) water vapour content of methane (or natural gas) is dependent on pressure, temperature and the salt content of the water in contact with the gas, according to the following:

- *Increasing pressure*: the amount of water in the gas decreases.

- *Increasing temperature*: the amount of water in the gas increases.
- *Increasing salt concentration*: the amount of water in the gas decreases (due to vapour pressure lowering).

During gas production, the reservoir temperature can be relatively constant, but the pressure drop will have a significant effect on the water content in the gas. The impact is largest in the near-wellbore region where pressure drop is highest. Temperature changes have a major effect on water content during production of gas through the well and surface flowline.

The chart shown in Figure B.1 is a useful nomograph for estimating the water content of sweet natural gas saturated with water vapour [18]. The chart is not applicable to sour gas. The main chart is for a relatively low gravity gas (0.6 kg/m^3). Plotted on this graph is also an equilibrium curve of hydrate formation, which is a function of gas composition. Determination of water content by this chart produces an error not exceeding 4%, which is acceptable for engineering purposes.

Figure B.1 is useful as it is illustrative of the physico-chemical trends: the water content of a natural gas increases with the increase in temperature and decreases with increase in pressure. Moreover, the water content of natural gases drops with an increase in their molecular weight and with an increase in the water salinity.

As a field ages and reservoir pressure declines, the gas can contain more water vapour. The highest pressure-drop will be at the interface of the reservoir and the wellbore. Here is the greatest risk that water will evaporate, and salt deposited.

Commercially available software, such as *KBC's Multiflash, Calsep's PVTsim or Petroleum Experts' PVTp*, is widely used to calculate the water content of produced gas and to show if the wellbore is under conditions of water evaporation or condensation.

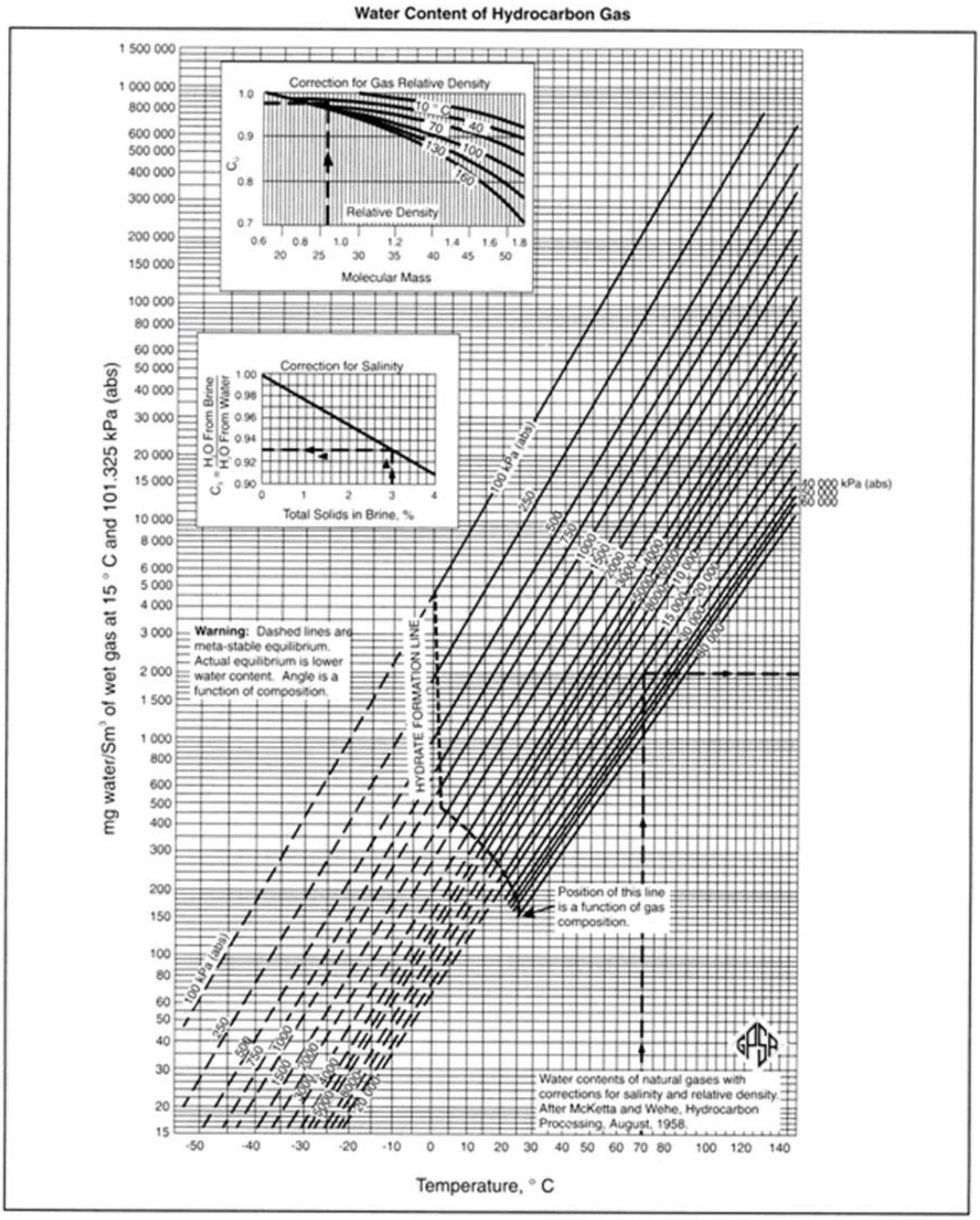

Figure B.1: Nomograph for estimating the water content of natural gas saturated with water vapour [18].

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