

High-Pressure High-Temperature Wellhead Systems: Reliability, Integrity and Risk Management for Complex Upstream Operations

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Abstract: Wellhead systems functioning under high pressure and high temperature involve a situation in which pressure containment, thermal expansion, sealing performance, materials compatibility, and observance of operational procedures all become closely interrelated. This review has gathered the most up-to-date literature published between 2020 and 2025 on the reliability, integrity and risk management of wellheads and of the other pressure-control barriers used in complex upstream operations. It examines the load paths from the casing and tubing all the way to the casing heads, tubing heads, spools, connectors, valves, seals and the Christmas-tree assemblies; the various types of degradation caused by pressure-temperature cycling, corrosion, erosion, fatigue, wellhead movement and the deterioration of the seals; and the increasing significance of continuous surveillance, digital twins and risk-based maintenance. A structured integrative review method was used, with clear eligibility criteria and in accordance with the PRISMA 2020 reporting framework, since a meta-analysis was not carried out as the body of evidence includes experiments, numerical models, field case studies, standards and review articles. The synthesis demonstrates that the reliability of HPHT systems is not mainly a question of the rating of any one component but rather results from the way in which design margins, transient loads, material-environment compatibility, the quality of installation and aging over time interact. The paper suggests a lifecycle integrity framework which connects qualification, barrier verification, condition monitoring, anomaly diagnosis, risk ranking, intervention planning and feedback. It concludes that in the future HPHT assurance should focus on representative full-envelope qualification, coupled thermo-mechanical models, health indicators for seals and connections, validated digital-twin decision support, and risk controls which remain effective even in the presence of uncertainty.

Keywords: High-Pressure High-Temperature (HPHT); Wellhead Systems; Pressure Control; Well Integrity; Risk Management; Thermo-Mechanical Loading; Corrosion.

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1. INTRODUCTION

The existing upstream projects are now focusing on greater depths, higher pore pressures,

increased temperatures, sour fluids, longer tiebacks, high-rate production, multistage stimulation, and more frequent intervention operations. The wellhead

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is no longer only a simple assembly of pressure-containing components; it has instead become the structural and hydraulic interface via which the loads from the casing and tubing, the annulus pressures, the operation of the valves, the flow occurring during production, the loads from external equipment, and the operational transients are transmitted. As a result, the more recent literature on well integrity considers wellhead performance as part of a lifecycle barrier system rather than as a separate equipment issue (Alsubaih *et al.*, 2025; Anunciação Jaculli *et al.*, 2022). This change is especially important in the case of HPHT services since both high pressure and high temperature can act together to reduce the available material margin, accelerate chemical degradation, alter seal behaviour, increase thermal movement, and cause cyclic stresses—factors which are not taken into account in basic static design evaluations.

The design, materials, testing, inspection, welding, marking, handling and purchasing requirements and recommendations for wellhead and tree equipment as set out in ISO 10423:2022 cover all these aspects. Nevertheless, the fact that the equipment satisfies the requirements laid down for it does not in itself ensure that its integrity will be kept over the years as the loads vary. NORSOK D-010:2021 advocates a more rigorous barrier approach according to which well integrity must be maintained and verified at all the various stages of drilling, completion, production, intervention, suspension and abandonment. There is a basic difference between qualification and continued fitness for service in the case of HPHT assets. A component may pass a manufacturing acceptance test but can later be affected by a combination of annulus pressure, thermal growth, bending, vibration, corrosion, seal ageing and loss of connection preload, all of which can cause the entire assembled system to approach a failure boundary.

The reference literature presented here demonstrates this systems approach. Alsubaih *et al.*, (2025) cite wellhead leaks, sustained casing pressure, casing degradation and sealing failures as examples of recurring integrity threats and stress the significance of continuous monitoring together with the use of digital technologies. Yuan *et al.*, (2024) show that in the case of high-temperature and high-pressure safety valves, risk results from the interaction of material, corrosion, manufacturing, installation, operational and maintenance factors more than from a single main cause; since both types of systems involve safety-critical pressure barriers the failure of which could lead to a quick escalation of consequences, the application of FMECA and Bow-tie analysis to them is feasible.

The review focuses on the HPHT wellhead and the pressure-control system located adjacent to it as part of the wider field of integrity studies. Its main point is that reliable HPHT performance can only be achieved by managing the interconnected mechanical, thermal, chemical, and organisational interactions throughout the entire lifecycle of the asset. Special emphasis is placed on the transfer of load from the casing to the wellhead, pressure-temperature cycling, the flanges and high-grade connections, elastomeric and metal-to-metal seals, corrosion and erosion, wellhead movement, the monitoring of the annulus, fatigue, digital monitoring, and risk-based maintenance. This thorough overview is aimed at engineers and asset-integrity specialists who need a technically solid basis on which to make defensible operating decisions based on design data and field observations. An additional complication is that HPHT wells generally pass through a number of different production phases rather than remaining in a single steady state. Procedures such as cleanup, ramp-up, changes to the choke, stimulation, shut-in, restart, workover, and late-life depletion can each result in different combinations of temperature gradient, pressure differential, vibration, and annular loading. Reliability assessments therefore have to take into account the operating sequences and the rates at which the transitions take place, since the most damaging event could be a transient that accounts for only a small part of the total service time.

2. Aim and Objectives

This review intends to provide a thorough understanding of the ways in which HPHT wellhead systems fail to stay reliable and to demonstrate how lifecycle risk controls can ensure pressure containment in complicated upstream operations. It is based on four objectives: to identify the main HPHT loading and degradation mechanisms that affect wellhead and tree assemblies; to assess the monitoring and diagnostic techniques which show the development of a loss of integrity; to compare the various risk-management approaches that link the different failure mechanisms with preventive and corrective actions; and to determine the design, maintenance, digitalisation, and research priorities that will enable integrity management to move from periodic verification to predictive assurance. Throughout the review, attention is paid to equipment qualification and the interactions between components, interfaces, operating envelopes, human actions, and data quality are stressed.

3. REVIEW METHODOLOGY

An integrative review using a structured method was chosen because the research question involves a wide range of types of evidence, such as peer-reviewed reviews, experimental studies, finite-

element and analytical models, field case histories, conference papers, digital-monitoring studies, and the current engineering standards. The report adheres to the PRISMA 2020 principles in terms of the transparent identification, eligibility, and synthesis of the studies, but it is not presented as a statistical meta-analysis since comparable effect sizes are generally not available among the studies that have been included (Page *et al.*, 2021). The publication window was limited to the period 2020–2025 in order to satisfy the requirement for up-to-date evidence.

The search terms were grouped into four categories on the basis of the search concepts: those relating to operating conditions, for example 'HPHT', 'high pressure', 'high temperature', and 'sour service'; those concerning equipment, such as 'wellhead', 'Christmas tree', 'casing head', 'tubing head', 'valve', 'seal', and 'connection'; terms associated with integrity, such as 'reliability', 'fatigue', 'corrosion', 'erosion', 'leak', 'wellhead movement', and 'sustained casing pressure'; and terms associated to management, for instance 'FMECA', 'Bow-tie', 'WIMS', 'risk-based inspection', 'digital twin', 'DAS', and 'predictive maintenance'. The papers were reviewed in order to ascertain if they addressed pressure containment, structural load transfer, sealing, monitoring, or decisions regarding integrity. Those studies which concentrated solely on reservoir performance and did not involve any barrier or equipment were excluded. Although older fundamental studies were referred to indirectly via recent reviews, they were not included as in-text evidence.

The synthesis of the data that has been compiled includes thirty sources covering the period from 2020 to 2025, comprising two existing standards together with the model papers attached to this document. The evidence has been grouped into five themes: design and qualification; mechanical and thermal reliability; chemical and tribological degradation; monitoring and diagnostics; and risk-informed operations. The findings were compared according to the mechanism rather than by location or operator. In the case of evidence relating to downhole safety valves, casing-cement systems, geothermal or storage wells, it was only included if the particular physical mechanism in question could be applied to HPHT wellhead service. This method permits triangulation without suggesting that all types of equipment have the same geometry or operating requirements. As a result, the review amounts to an engineering synthesis in that it identifies the mechanisms which are repeatedly observed, shows where field evidence supports numerical predictions, and points out the areas in

which qualification data or validated prognostics are still missing.

4. HPHT Operating Context and Wellhead Architecture

The system used at the wellhead under HPHT conditions has to ensure containment even though it is subjected to loads that are much greater than those experienced by the visible part of the surface assembly. Pressure acts internally on the bores, cavities, valves, seals, and the annuli, while the casing and tubing strings carry the axial force caused by weight, pressure end effects, thermal expansion, the restrictions imposed by the packer, and wellbore friction. When the system is being used offshore, movement of the riser and environmental loads can cause bending and fatigue; on the other hand, onshore systems may be influenced by foundation settlement, subsidence, thermal growth, or intervention loads. Jaculli *et al.*, (2020) regard wellhead integrity as a structural issue that encompasses the entire lifecycle of the system, and subsequent reviews stress that these load paths should be analysed as a single group rather than being treated as separate checks (Anunção Jaculli *et al.*, 2022; Alsubaih *et al.*, 2025).

A typical functional stack consists of casing heads, casing spools, tubing heads or spools, hangers, annular seals, connectors, master and wing valves, swab valves, chokes, flanges, studs, gaskets, and instrumentation. Even if each of the components has an adequate nominal pressure rating, the reliability of the system is determined by the interfaces; thermal expansion in long strings may cause the axial load to be transferred to the hangers and to the bodies; pressure cycling can change the contact stress at the sealing surfaces; bending can affect the way the load is distributed on the flanges; and repeated make-up or intervention can lead to damage of the threads or seal pockets. Although ISO 10423:2022 lays down the design and performance requirements for wellhead and tree equipment, specific asset load envelopes are still required since the combinations used in the field cannot be described by a single pressure-temperature point.

The HPHT qualification must therefore be regarded as one concerned with an envelope problem. In order to illustrate this way of thinking as it applies to high-temperature and high-pressure downhole safety valves, Yuan *et al.*, (2023) have worked out the performance-envelope boundaries on the basis of the mechanical failure criteria. Similarly, the same line of reasoning applies at the wellhead: safe operation depends on combinations of pressure, temperature, axial force, bending moment, cycles, environment, and time. If the operating point changes, the limiting failure mode can move from

yielding to seal extrusion, fatigue, connection leakage, or material wear. Figure 1 displays these coupled pathways.

It is likewise necessary to examine the interaction between the casing and the cement at the surface, as changes in temperature and pressure may cause debonding at the interface, result in a free casing length, and lead to either an upward or downward displacement of the wellhead. As Zhou *et al.*, (2024) note, when modelling wellhead movement the effect of debonding at the casing-cement interface is taken into account, which is the reason why surface displacement can be due to a loss of restraint in the subsurface and not simply to elastic expansion. Other studies have shown that pressure cycles can cause interface cracks to open or to extend and can also alter the stress state of the casing (Wang *et al.*, 2021; Alberdi-Pagola and Fischer, 2024). The practical

consequence is that wellhead displacement, annulus pressure, strain, and seal condition all have to be considered together. A stable pressure reading does not mean that no undetected structural movement has occurred, and a movement alarm should not be diagnosed unless the temperature record, the cement restraint, and the string configuration have first been understood. Similarly, barrier hierarchy is just as important. Primary flow containment can be achieved through the tubing and the production valves, while secondary containment depends on the annular seals, the casing, the wellhead bodies, and the ability to close independently. Under high-pressure and high-temperature (HPHT) conditions, it is essential to make sure that any apparent redundancy is in fact independent; if two barriers are subjected to the same thermal movement, corrosive medium, installation error, or structural load, they could have a common-cause vulnerability.

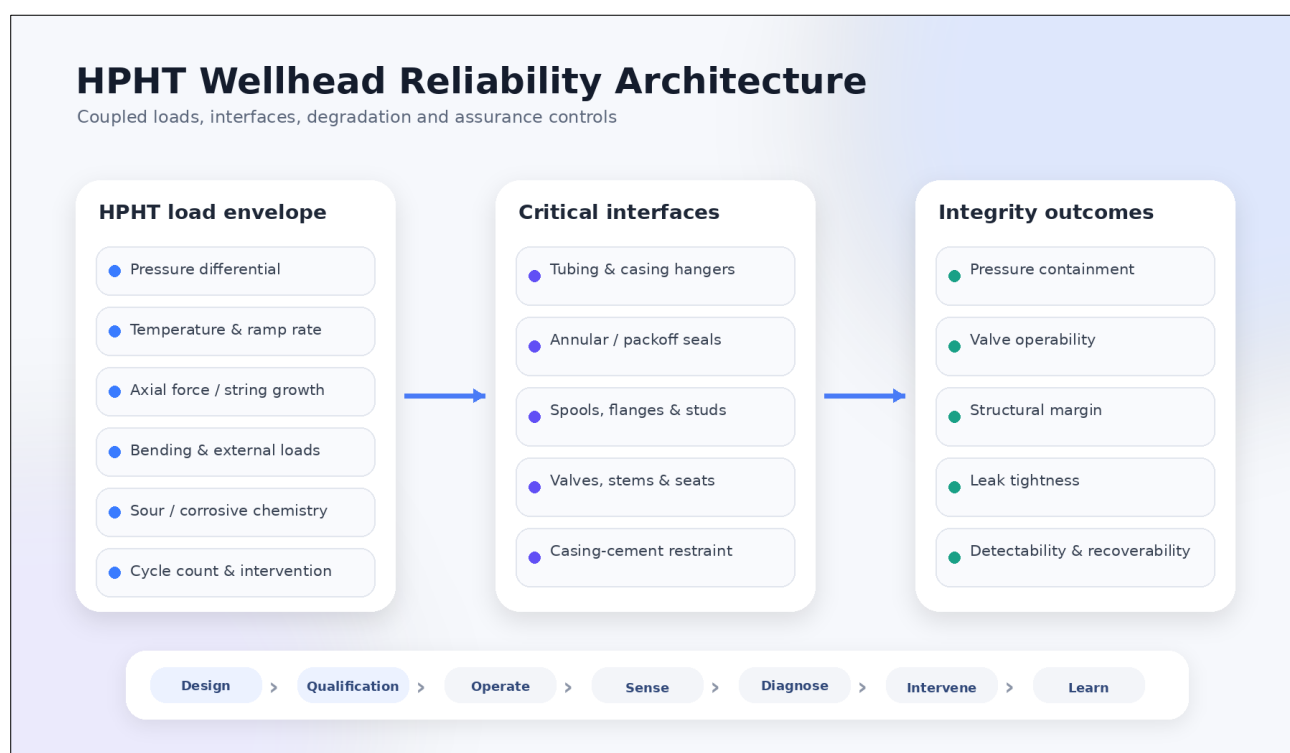


Figure 1: HPHT wellhead reliability architecture

5. Reliability and Dominant Failure Mechanisms

The high reliability of HPHT systems is primarily the result of a number of interacting failure mechanisms, even though these mechanisms may start off slowly they will eventually lead to leakage, a loss of barrier function, impaired valve operation, or structural failure. Table 1 gives a list of the main mechanisms, the field indicators, the consequences, and the measures taken to control them. The first of these measures is pressure-temperature cycling. When the casing and tubing are heated they expand and when they are cooled reverse strain takes place. If the strings are held in place by the cement, the

packers, the hangers, or by friction, the thermal strain becomes axial stress and causes local bending. After a number of cycles, low-cycle fatigue may develop at geometric discontinuities, at the roots of the threads, at the welds, at the transitions between flanges, and in areas where the load sharing changes. Alsubaih *et al.*, (2025) note that cyclic loading is a constant cause of integrity problems, and Han *et al.*, (2023) show that repeated exposure to elevated temperature conditions can gradually affect the integrity of the cement interface. In an HPHT wellhead the effects are not limited to casing fatigue since changes in axial load also influence hanger contact, body stress, flange

compression, seal contact pressure, and valve alignment.

A further reason is the reduction in the quality of the connection and sealing. Regardless of whether the connections are flanged, studded, threaded, or of the premium type, all of them rely on a controlled preload, the condition of the surfaces, the geometry, and the material behaviour. If the make-up torque is too high or too low, the reliability of the seal is reduced and repeated thermal cycles can lead to a redistribution of the contact stress. Yang *et al.*, (2023) demonstrate how sensitive the sealability of premium connections is to make-up torque, thus supporting the general notion that the quality of the installation becomes part of the reliability margin. Static seals are prone to extrusion and compression set, while dynamic stem packing is affected by friction, wear, and chemical exposure. Metal-to-metal seals avoid some of the limitations linked to elastomers but still demand high-quality contact surfaces and controlled deformation. In practice, leakage can occur because of damaged seal pockets, gasket relaxation, corrosion products, debris, incorrect assembly, or a loss of bolt preload even if the pressure-containing body is still structurally sound.

Elastomers tend to perform poorly when subjected to high temperature, high pressure and sour conditions: heat accelerates ageing and can cause the polymers to either harden or soften; high pressure increases the quantity of gas that is absorbed; rapid depressurisation can lead to damage as a result of the quick release of gas; and aggressive fluids cause the seal to swell, become brittle, or undergo chemical attack. According to Yuan *et al.*, (2024), sealing deterioration, corrosion and material defects are the primary causes of failure in high-temperature, high-pressure safety valves. Although the equipment is situated downhole, the same degradation mechanisms affect wellhead packoffs and valve stem seals. It therefore follows that the materials should be tested under conditions that correspond to the actual fluid chemistry, pressure, temperature, decompression rate, cycle count and mechanical gap — not merely on the basis of a nominal temperature rating.

The fourth important hazard is corrosion. In wells working at high pressure and high temperature it is possible for CO₂, H₂S, chlorides, organic acids, produced water, oxygen which enters during interventions, and deposits that create local electrochemical cells to be present. Solovyeva *et al.*, (2023) look at the different ways of controlling corrosion downhole, for example by selecting suitable materials, applying coatings, using inhibitors, and carrying out protective measures,

while Askari *et al.*, (2021) point out that the effectiveness of inhibitors depends on chemistry, the method of delivery, and the operating conditions. Obot *et al.*, (2023) also emphasize that the risk of sweet and sour corrosion arises from the interaction of fluid and process variables. At the wellhead corrosion can cause a decrease in wall thickness, damage to the sealing surfaces of the pits, impair the studs, weaken the stems, and lead to roughness which affects the operation of the gaskets or packing. In the case of sour service cracking must be taken into account, and it is therefore necessary to control hardness, take into account the metallurgy, ensure the quality of the welding, and keep material traceability.

Erosion and erosion-corrosion become significant in cases of a high-velocity multiphase flow containing sand, scale, or other solids as the flow goes through narrow sections such as chokes, valve seats, tees, and areas where the direction of the flow changes. As Rao and Mulky (2023) point out, a synergistic effect occurs in erosion-corrosion since the mechanical removal of the protective film exposes fresh metal and therefore accelerates the deterioration. If metal is lost in a given area the shape of the valve may alter and this can result in an increase in the pressure drop, while the solids can leave scratches on the seats and as a result the valve is not able to close fully. Since the erosion rate is greatly affected by velocity, particle loading, impact angle, and the condition of the material, inspection must be carried out in response to changes in production rather than on a fixed calendar schedule.

The fourth mechanism is related to structural movement and fatigue. The wellhead may move as a result of thermal expansion, because of the debonding of the casing and cement, due to elongation caused by pressure, as a consequence of the formation becoming compacted, as a result of the behaviour of the foundation, or because of the loads exerted by external equipment. Zhou *et al.*, (2024) state that interface debonding can have a significant effect on the predicted movement, and Deng *et al.*, (2021) reach the same conclusion in that interface failure causes a change in casing stress when there is non-uniform in-situ loading. This kind of movement can lead to bending moments being transferred to the spools, connectors, and tree assemblies by altering their alignment and by inducing secondary stresses which are not considered in simple pressure design. Offshore systems also suffer from additional cyclic loads which are transmitted through the risers and conductors, so that fatigue damage can accumulate even if the peak stresses remain below the yield point.

A different method involves looking at the pressure in the annulus; if the casing pressure is kept constant, this might indicate that there is communication taking place via the tubing, the packers, the casing, the cement, or the wellhead seals. Ibukun *et al.*, (2024) emphasize that SCP is a problem which affects the whole lifecycle of the system and that it should be diagnosed rather than simply depending on routine bleeding. Because the wellhead serves not only as a point for monitoring but also as a possible path for leakage, pressure trends must be considered together with the bleed-down and build-up behaviour, the temperature, the present production conditions, and the known configuration of the barriers. Abnormalities in the annulus can also place additional stress on the seals or on the casing strings and therefore turn a diagnostic symptom into a further mechanical issue.

Human and organizational factors also have an effect on reliability; even if the overall design is durable it can still be compromised by applying the wrong torque, damaged sealing surfaces, contamination during assembly, incomplete pressure testing, the use of the wrong material, a slow response to anomalies, and poor management of change. As Yuan *et al.*, (2024) point out, FMECA and Bow-tie analysis can be used to demonstrate that manufacturing, corrosion protection, installation, operating practice, and maintenance form causal chains. In the case of HPHT wellheads this implies that integrity assurance must treat procedures, competency, verification records, and configuration control as engineered barriers. A high-specification tree that is installed outside of its approved assembly process is not a reliable system.

Table 1: Dominant HPHT wellhead failure mechanisms, indicators and primary controls

Mechanism	Typical HPHT trigger	Early indicators	Potential consequence	Primary controls
Pressure–temperature cycling	Rapid ramping; repeated startup/shutdown; constrained string growth	Movement, strain drift, recurring leak/test changes	Fatigue, yielding, seal-contact loss, misalignment	Thermo-mechanical envelope analysis; cycle tracking; movement limits; fatigue assessment
Seal degradation / RGD	HPHT exposure; gas absorption; sour/chemical attack; rapid depressurization	Packing leakage, declining test performance, extrusion fragments	Loss of pressure containment or valve function	Representative seal qualification; decompression control; compatible elastomer/metal seals; planned replacement
Connection / preload loss	Incorrect make-up; thermal relaxation; bending; damaged sealing surface	Bolt/tension changes, seepage, repeated retorque, local strain	Flange/thread leakage; jump-out or connection damage	Calibrated torque/tension; clean assembly; protected seal faces; verification after thermal events
Corrosion / sour cracking	CO ₂ , H ₂ S, chlorides, produced water, oxygen ingress, deposits	Wall-loss trend, pitting, corrosion products, hardness/material nonconformance	Reduced pressure capacity; cracked studs/stems; damaged seal surfaces	Material selection; hardness control; inhibition/coatings; NDE; corrosion monitoring
Erosion / erosion-corrosion	High velocity; sand/scale; choke restriction; multiphase flow	Metal-loss near bends/valves; seat damage; changing choke response	Local thinning; valve leakage; loss of operability	Velocity/solids control; resistant trim; inspection tied to production changes
Wellhead movement / structural fatigue	Thermal string growth; casing-cement debonding; subsidence; riser loads	Displacement, tilt, strain, alignment change, vibration	Bending overload; fatigue; seal and connector distress	Movement baseline; coupled structural model; support/alignment controls; fatigue monitoring
Sustained casing pressure / annular communication	Barrier leak; thermal pressure; cement or packer defects; wellhead seal leak	Build-up after bleed-down; pressure-temperature correlation; repeated venting	Escalating annular load; external leak; loss of barrier independence	Diagnostic bleed/build-up tests; source localization; risk ranking; timely repair

6. Integrity Monitoring and Diagnostics

The monitoring system has to be able to detect not only an immediate loss of containment but also any indications that point to a decreasing margin of safety. Traditional procedures involve carrying out visual inspections, performing leak checks, testing the valves' operation, monitoring the pressure in the annulus, carrying out pressure tests, carrying out non-destructive examinations, looking for corrosion, and checking the maintenance record, since these methods deliver a clear verification of the barrier's integrity. However, HPHT systems can make use of data that are collected more frequently and which are capable of picking up transient behaviour; trends in pressure and temperature can reveal abnormal communication in the annulus; measurements of displacement or strain can pick up thermal expansion and structural movement; and acoustic or vibration signatures may indicate leakage, valve instability, or changes in the support conditions.

Distributed fibre-optic sensing means that surveillance can shift from making individual measurements to obtaining continuous spatial data. As Haavik (2023) demonstrates, low-frequency distributed acoustic sensing can be used for in-well monitoring and for assessing well integrity, and Haavik (2024) shows how distributed sensing can be applied to monitor the liquid level in the annuli. Although the fibre is generally installed downhole, its value in relation to wellhead integrity lies in linking surface symptoms to the time and location of subsurface events; for example, when annulus pressure increases, the distributed data can assist in distinguishing between the thermal effects and fluid movement or leakage.

Digital methods can combine all these different data streams. Anjos *et al.*, (2020) developed a real-time digital-twin method for monitoring well integrity, and Straw *et al.*, (2022) put this approach to use in relation to both predictive performance and

integrity as well. Aditama *et al.*, (2022) present an artificial-intelligence-based technique for monitoring, explaining that anomaly classification can improve engineering review. The important point is that what is needed is not innovation in algorithms but rather traceable decision support. A useful HPHT digital twin should preserve the physical load envelope, compare the actual conditions with the predicted behaviour, take uncertainty into account, and keep a record of the reason why an alert was issued; it must not replace barrier testing or engineering judgment.

Table 2 gives a comparison of the different monitoring methods in terms of their diagnostic value and limitations. The most effective programmes involve both the direct checking of the barrier and the use of indicators which show the condition of the barrier; pressure tests verify containment at a given time, corrosion measurements give a measure of the material loss, trends in movement and strain indicate the level of structural loading, and the continuous data allow any differences between inspections to be detected. With this multi-tiered approach, it is less likely that a single noisy signal will lead to an unnecessary shutdown or that a slowly deteriorating condition will go unnoticed until the next planned test. Data governance plays a vital role in guaranteeing the reliability of the monitoring. The sensors must have calibration records, specified ranges, time synchronisation, drift checks, and configuration control so that the trends can be compared after maintenance has been carried out. The alarm thresholds should be based on the expected thermal and operational signature of each well rather than on a general value for the entire fleet. Contextual data such as choke position, flow rate, intervention status and ambient conditions can prevent normal transients from being wrongly treated as integrity events.

Table 2: Monitoring and diagnostic technologies for HPHT wellhead integrity decisions

Method	Primary target	Strength	Limitation	Decision use
Annulus pressure & temperature trending	SCP, communication, thermal response	Continuous, inexpensive, operationally intuitive	Source may be ambiguous; thermal effects can mimic leakage	Trigger enhanced diagnostics, bleed/build-up testing, shutdown thresholds
Valve / pressure-barrier testing	Leak tightness and functional isolation	Direct verification of barrier function	Point-in-time result; testing can disturb system	Confirm availability of preventive/recovery barriers
UT/MPI/other NDE	Wall loss, cracking, surface defects	Direct material-condition evidence	Access dependent; local coverage; interpretation skill required	Update pressure capacity, repair or replacement need
Corrosion mapping /	General and localized metal loss	Trendable degradation rate	May miss inaccessible seal	Adjust inspection interval and remaining-margin assessment

Method	Primary target	Strength	Limitation	Decision use
thickness monitoring			pockets or internal trim	
Displacement / strain / vibration sensing	Thermal growth, bending, fatigue precursors, support changes	Captures structural behavior during transients	Requires baseline and load-context interpretation	Check movement limits, fatigue accumulation, structural assessment
DAS/DTS / distributed fiber optics	Fluid movement, thermal anomalies, acoustic events, annulus behavior	Spatially continuous information along wellbore	Installation and interpretation complexity	Localize cause behind a surface pressure or movement symptom
Digital twin / AI analytics	Deviation from expected state; anomaly patterns; leak inference	Fuses multiple sensors and models for early warning	Model drift, sensor quality, uncertainty, explainability	Prioritize diagnosis and intervention; never replace physical verification

7. Risk Management for Complex Upstream Operations

Risk management transforms technical observations into priorities and actions; for HPHT wellheads a useful framework begins by identifying failure modes, links the causes to the top events and their consequences, assesses the current preventive and recovery measures, and adjusts the risk as new evidence becomes available. Since FMECA requires an explicit examination of function, failure mode, cause, consequence, detectability, and criticality, it is suitable for use at the component level. Yuan *et al.*, (2024) apply FMECA to high-temperature and high-pressure safety valves and then use Bow-tie analysis to connect the causes of failures with their consequences and with the controls. This sequence can be directly applied to wellhead systems, where a "seal leak" or "valve fails to isolate" should be traced back to material, load, assembly, corrosion, or operational causes rather than being treated as a standalone event.

Bow-tie analysis is useful since it distinguishes between prevention and mitigation. Examples of preventive barriers are material qualification, design margins, verified torque, seal compatibility, corrosion inhibition, pressure-envelope control, and fatigue assessment. Recovery barriers consist of leak detection, remote shutdown, secondary isolation, emergency depressurization, exclusion zones, and well-kill capability. A barrier should only be given credit where there is a clearly defined performance standard and evidence that it is available; this stops risk registers from including general controls which cannot be verified.

The organizational framework for this approach is provided by Well Integrity Management Systems. According to Yakoot *et al.*, (2021), WIMS maturity involves a progression from a reactive approach to one of predictive management, whereas Semwogerere *et al.*, (2025) stress the significance of integrated monitoring, remaining-life assessment and risk analysis for wells that are aging. For HPHT assets, risk ranking must be dynamic. A well can be promoted to a higher category if the annulus pressure increases, if there are repeated seal failures, if the corrosion rate rises, if there is unexpected wellhead movement, or if the well is operated outside the validated load envelope. On the other hand, successful diagnostics together with the restoration of barriers can allow for a controlled return to service.

A closed-loop integrity process is shown in Figure 2. This process starts with design basis and qualification, sets up a baseline condition, keeps a close watch on the operating data, detects any anomalies, updates the risk assessment, chooses an intervention, checks that the intervention was effective, and then incorporates the knowledge acquired back into the model. The framework enables risk-based inspection without causing the inspection intervals to become simply probabilistic results. It is necessary that consequence severity, uncertainty, detectability, redundancy, and the credibility of recovery barriers all remain visible. In the case of HPHT service, uncertainty itself acts as a risk driver since small mistakes in temperature, load transfer, material condition, or seal performance can use up the limited margin.

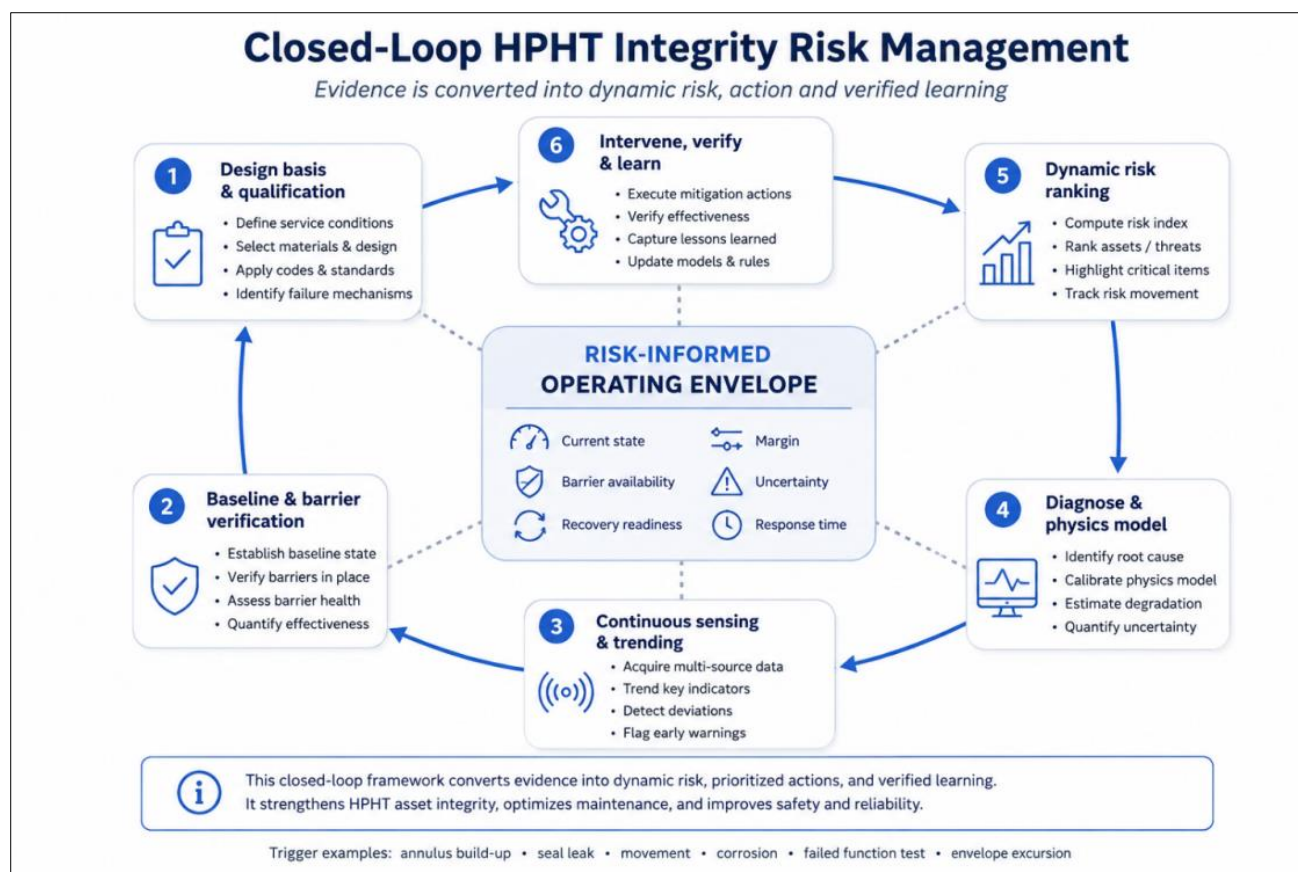


Figure 2: Closed-loop HPHT integrity risk-management

8. Reliability Enhancement and Maintenance Strategy

Reliability can only be increased by taking account of the full range of operating conditions and not simply focusing on the maximum pressure; the different kinds of load should be combined, such as pressure, temperature, axial force, bending, external loads, transient rates, and possible off-normal conditions. Although ISO 10423:2022 provides the equipment framework, the analysis concerning the asset must illustrate the way the entire system behaves as the various loads pass through the hangers, spools, flanges, studs, and seals. In the case where fatigue is a possibility, both cycle counting and local stress concentrations have to be considered. When movement is expected, allowable displacement and alignment criteria should be established before startup.

When picking materials and seals, it is necessary to consider the degree of exposure and to provide appropriate qualification evidence; in situations involving sour or corrosive service it makes sense to use materials that are resistant to corrosion, to ensure that the hardness is controlled, to apply suitable coatings and inhibitors, and to verify chemical compatibility (Solovyeva *et al.*, 2023; Obot *et al.*, 2023). The reliability of the connections can be increased by carrying out a clean assembly, by using

calibrated torque or tensioning, by protecting the sealing surfaces, by making sure that the components are traceable, and by carrying out a check after installation. The seal systems should be qualified with regard to the rate of decompression and thermal cycling, as well as for the static pressure-temperature limits.

Maintenance ought to be guided by risk while considering the actual condition. Even though scheduled tasks are necessary for regulatory and functional inspections, the frequency of these tasks should be decided according to evidence of degradation. When the corrosion rate is increasing, there are repeated anomalies in annulus pressure, the cycle count is high, the condition has moved beyond the baseline, or the performance of the valve tests is worsening, the intervals between inspections or interventions must be reduced. Alberdi-Pagola and Fischer (2023) highlight how difficult it is to directly quantify the loss of integrity resulting from cement cracking, and this backs the notion of using a number of different indicators rather than relying on conclusive evidence from a single diagnostic method.

The most effective method of maintenance is based on prevention, early detection, and having recovery plans ready. It is essential that, before an HPHT anomaly occurs, critical spares, the tools

required for carrying out an intervention, the procedures for isolation, and the contingency plans are all available. Even though digital models can assist with forecasting, each assessment of the remaining life must state the assumptions made and also include the uncertainty connected with it. The aim is not to extend the time between interventions; instead, it is to make sure that the system stays well within a safe, closely monitored, and recoverable operating range.

9. DISCUSSION

The evidence supports the view that the integrity of HPHT wellheads should be understood in terms of systems; it is seldom possible to explain wellhead failures simply on the basis of the rated working pressure, since they are in fact the result of a number of interacting factors—temperature variations lead to axial loading, axial loading then changes the contact stress, the contact stress affects the sealing, chemical exposure alters the material properties, corrosion reduces the cross-sectional thickness, movement causes bending, and the quality of maintenance determines whether early warning signs are detected. That is the reason why reliability models which are based only on the frequencies of component failure can be misleading when there are significant differences between the operating envelopes and the degradation states of the various wells.

It should also be noted that structural soundness and pressure integrity need to be considered together. Movement of the wellhead surface may indicate what is occurring to the subsurface casing-cement and the annulus pressure can both show the situation and place a load on a damaged barrier. The research carried out by Zhou *et al.*, (2024), Wang *et al.*, (2021), and Alberdi-Pagola and Fischer (2024) shows that the condition of the interface has an effect on deformation and cracking. If movement, pressure, and seal performance are dealt with in separate workflows, the causal relationships might be ignored.

Thirdly, digitalisation is most effective when it improves barrier governance. Even though digital twins and AI can aid in the detection of irregularities and in organising evidence, the review does not state that physical verification should be replaced by prediction. As Abdo *et al.*, (2023) demonstrate, digital twins can be used for leak detection and quantification, but such systems depend on trustworthy sensors, calibrated models, and known configurations. The result is a mature approach that takes the form of a hybrid integrity system in which engineering standards, direct testing, continuous sensing, mechanistic models and risk logic all support each other. Regarding the economic aspect, risk-

based integrity is sometimes presented as a way of reducing inspection costs, but in the case of HPHT services its main advantage is in preventing poorly targeted spending. By using continuous information, specialised inspections can be directed to the mechanisms most likely to consume margin, and verified stable conditions can avoid unnecessary intrusive work. The economic benefit therefore comes about because of better decisions and less unplanned exposure, not simply from longer maintenance intervals.

10. Research Gaps and Future Directions

There are still a few gaps. First of all, the data available in the open literature on full-scale qualification tests involving seals, connections, and assembled wellheads under joint HPHT cycling, sour chemistry, bending, and rapid depressurization is limited. Second, the fatigue and movement models require more verification on the basis of long-term field measurements, in particular when casing-cement debonding has an impact on load transfer. Third, corrosion, erosion, and seal degradation are often modelled separately even though they can interact at valves and sealing surfaces. Fourth, the research concerning digital twins requires standardised procedures for reporting uncertainty, criteria for validation, cybersecurity controls, and well-defined guidelines as to when a prediction may be used to alter operating limits.

Research in the future should be directed towards the development of health indicators that are based on physical principles and that directly link sensor data to the barrier margin. This might include indicators such as the estimated loss of flange preload, the degradation of seals as a result of contact, strain adjusted with respect to movement, pressure capacity taken into account for corrosion, and damage that depends on the number of cycles. Field data sets should not only include information on failures but also on operating transients and maintenance actions. Anonymised datasets from different operators could help to improve learning in the case of rare events without at the same time compromising confidential information. Risk models must also evaluate recovery readiness in the same way as they do prevention, since complex HPHT operations require a credible capacity to isolate and carry out interventions when it is not possible to rapidly reduce uncertainty. The research should also examine common-cause degradation affecting nominally redundant barriers. Thermal movement can affect more than one seal and connection at the same time, and a single corrosive fluid can corrode several components within the same pressure boundary. Reliability models which assume that the failure of components is independent may therefore be overestimating the level of redundancy.

Probabilistic models should consider dependency, the uncertainty about the effectiveness of inspections, and changes in the operating state. There is a need for more full-scale tests to be published in order to calibrate these links and to determine how far the results obtained from laboratory coupons, component tests, and assembled systems can be transferred to one another.

11. CONCLUSION

HPHT wellhead systems are interfaces of vital reliability; dependability in pressure containment, structural support, sealing, material compatibility, monitoring, and operational control all come together. The current body of literature indicates that integrity is affected by coupled pressure-temperature cycling, fatigue, wellhead movement, degradation of the connections and seals, corrosion, erosion, anomalies in annulus pressure, and weaknesses due to human or corporate factors. Since no one inspection method or design rating can reflect this varying risk state.

The review therefore recommends adopting an approach based on five principles. The first of these is to evaluate the entire system under realistic combined loads and environmental conditions. The second principle is to treat interfaces—such as hangers, connections, seal pockets, the casing-cement restraint, and valve closures—as significant reliability features instead of considering them as minor points. The third principle consists of combining direct barrier testing with a constant flow of pressure, temperature, movement, strain, corrosion, and acoustic data. The fourth principle requires the use of FMECA and Bow-tie analysis within a well-established WIMS in order to connect the evidence to both preventive and corrective barriers. The fifth principle is to use digital twins and AI as transparent layers to aid decision-making by quantifying deviation and uncertainty without taking the place of physical verification.

With regard to carrying out complex upstream operations, the main aim is to obtain a clear margin: the operators have to know where the current wellhead condition lies in relation to the approved limits, identify the degradation mechanisms which are currently operating, be aware of the barriers that are still available, and decide what action should be taken if the condition worsens. Moving from a system of periodic compliance to one that is based on evidence and is predictive is the most effective approach for guaranteeing safer production, reducing unplanned downtime, and improving the defensibility of HPHT risk management.

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