MESTRO JURNAL ILMIAH
Jurnal homepage: http://jurnalmestro.untag.ac.id

Piping Stress Analysis for Offshore Platform Reactivation Using CAESAR II: Compliance Verification with ASME B31.3

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INFORMASI ARTIKEL

NASKAH DITERIMA : 12 April 2026
DIREVISI : 25 Mei 2026
DISETUJUI : 25 Juni 2026

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DOI: 10.47685/mestro.v8i01.819

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Abstract

Offshore platform reactivation projects routinely require re-verification of piping flexibility once tie-in routings, pressure ratings, or service conditions change, yet published case studies that report full, code-referenced compliance workflows for this specific scenario remain limited compared to the wider body of CAESAR II piping stress literature. This paper addresses that gap by presenting a comprehensive piping stress analysis for the reactivation of an offshore production platform (anonymized as GTB Platform) under an Engineering, Procurement, Construction, and Installation (EPCI) contract operated by an Indonesian upstream oil and gas operator (anonymized as Company/CPY). The analysis was performed using CAESAR II Version 2019 (11.0) for piping system Model 03, covering the line from the Pig Receiver (R-002) to the Upstream High-Integrity Pressure Protection System (Z-010), and was verified against ASME B31.3 (2020) Process Piping requirements across hydrotest, sustained, operating, occasional, and thermal expansion load cases. The lines analyzed are 8-inch and 10-inch carbon steel pipes (ASTM A106 Grade B and API 5L X52) with design pressure up to 1,550 psi and design temperature of 200°F. Results show that all maximum stress ratios remain below the ASME B31.3 allowable limit of 100%, with the highest sustained stress ratio at 60.8%, occasional stress ratio at 61.2%, and thermal expansion ratio at 23.0%. Maximum displacement under the operating condition is 9.013 mm, equal to 9.0% of the 100 mm project threshold. Flange leakage verification using the Pressure Equivalent Method yields a maximum ratio of 77.72% of the ASME B16.5 allowable rating, and the fundamental natural frequency of 4.585 Hz exceeds the 4 Hz minimum recommended for offshore piping by DNVGL-RP-D101. These results, together with a quantitative benchmarking against comparable published CAESAR II case studies, indicate that the reactivated piping configuration is conservatively designed with adequate margin for in-service uncertainty.

Keywords: *ASME B31.3; CAESAR II; offshore platform reactivation; piping flexibility analysis; piping stress analysis*

Abstrak

Proyek reaktivasi platform lepas pantai secara rutin memerlukan verifikasi ulang fleksibilitas pemipaan apabila terdapat perubahan pada jalur sambungan (*tie-in routing*), rating tekanan, maupun kondisi layanan. Namun demikian, studi kasus yang dipublikasikan dan menyajikan alur kerja kepatuhan secara lengkap dengan rujukan kode standar untuk skenario spesifik ini masih terbatas jika dibandingkan dengan literatur analisis tegangan pemipaan CAESAR II yang lebih luas. Makalah ini mengisi kesenjangan tersebut dengan menyajikan analisis tegangan pemipaan secara komprehensif untuk reaktivasi sebuah platform produksi lepas pantai (dianonimkan sebagai Platform GTB) dalam kerangka kontrak *Engineering, Procurement, Construction, and Installation* (EPCI) yang dioperasikan oleh perusahaan operator minyak dan gas bumi hulu Indonesia (dianonimkan sebagai Company/CPY). Analisis dilaksanakan menggunakan perangkat lunak CAESAR II Versi 2019 (11.0) untuk sistem pemipaan Model 03, yang mencakup jalur dari *Pig Receiver* (R-002) hingga *Upstream High-Integrity Pressure Protection System* (Z-010), serta diverifikasi terhadap persyaratan ASME B31.3 (2020) *Process Piping* pada kondisi pembebanan uji hidrostatis, berkelanjutan (*sustained*), operasi, insidental (*occasional*), dan ekspansi termal.Pipa yang dianalisis merupakan pipa baja karbon berdiameter 8 inci dan 10 inci (ASTM A106 Grade B dan API 5L X52) dengan tekanan desain hingga 1.550 psi dan temperatur desain sebesar 200°F. Hasil analisis menunjukkan bahwa seluruh rasio tegangan maksimum berada di bawah batas yang diizinkan oleh ASME B31.3 sebesar 100%, dengan rasio tegangan berkelanjutan tertinggi sebesar 60,8%, rasio tegangan insidental sebesar 61,2%, dan rasio ekspansi termal sebesar 23,0%. Perpindahan maksimum pada kondisi operasi adalah 9,013 mm, setara dengan 9,0% dari nilai ambang batas proyek sebesar 100 mm. Verifikasi kebocoran flens menggunakan *Pressure Equivalent Method* menghasilkan rasio maksimum sebesar 77,72% dari rating yang diizinkan oleh ASME B16.5, dan frekuensi alami fundamental sebesar 4,585 Hz melampaui batas minimum 4 Hz yang direkomendasikan untuk pemipaan lepas pantai berdasarkan DNVGL-RP-D101. Hasil-hasil ini, bersama dengan pembandingan kuantitatif terhadap studi kasus CAESAR II yang telah dipublikasikan sebelumnya, mengindikasikan bahwa konfigurasi pemipaan yang direakvitasi dirancang secara konservatif dengan margin yang memadai untuk mengakomodasi ketidakpastian selama masa operasi.

Kata kunci: ASME B31.3; CAESAR II; reaktivasi platform lepas pantai; analisis fleksibilitas pemipaan; analisis tegangan pemipaan

I. INTRODUCTION

Many mature offshore oil and gas fields in Indonesia contain remaining reserves that can only be economically recovered if idle wells or shut-in platforms are reactivated and reconnected to existing production infrastructure [1], [2]. The Indonesian Petroleum Association reports that activating idle fields is considered strategically preferable to new exploration, since it can deliver incremental production in a comparatively short time frame at lower technical risk [2]. The case examined in this paper concerns a platform, anonymized here as the GET (GETA) Platform, which is one of several production assets in the area surrounding the GTB Platform, approximately 9 km away. The GET Platform was discovered in 1994 through the exploration well GETA-1 and delineated with GETA-2, commenced first production in 2001, and reached peak output in 2002. Production was subsequently shut in starting 2017 following a leak in the existing 12-inch three-phase pipeline connecting GET to GTB.

A Geoscience, Geophysics, and Reservoir (GGR) evaluation confirmed the presence of remaining reserves in the GET Field, providing the technical and economic basis for reactivation. Comparable reactivation studies in Indonesian fields have demonstrated favorable economics; for example, a high-water-cut well reactivation in the Bayu Field reported a net present value of approximately 5.15 million USD with an internal rate of return exceeding 500% [3], underscoring that brownfield reactivation can be highly cost-effective when supported by sound technical evaluation. For the present case, the reactivation plan involves replacing the deteriorated 12-inch pipeline with a new 10-inch three-phase pipeline of approximately 9 km, designed to handle 14.7 MMSCFD of gas, 139.3 BCPD of condensate, and 2002.7 BWPD of water. Production fluid from the GET Platform will be routed to the GTB Platform, where it will be combined with production streams from GTB wells and three satellite platforms, anonymized here as GTE, GTD, and GRF.

As part of the GTB Platform modification scope, a comprehensive piping stress analysis is mandatory to ensure structural integrity and code compliance for all modified piping systems. Piping stress analysis is a critical activity in offshore facility engineering: it verifies that piping can withstand the combined effects of internal pressure, thermal expansion, dead weight, and dynamic loading without exceeding material allowable stresses, and without imposing excessive reaction loads on connected equipment nozzles and support structures [1]. Underestimating these effects can lead to nozzle overload, flange leakage, or fatigue cracking at welds and small-bore connections, all of which are recognized causes of unplanned shutdowns on offshore facilities [4].

CAESAR II, developed by Intergraph (now part of Hexagon), is the de facto industry-standard software for computerized piping flexibility analysis, implementing the static and dynamic provisions of ASME B31.3 and related piping codes [6]. Its application has been demonstrated across a wide range of offshore and onshore contexts, including methodological studies that combine pipe routing optimization with iterative support placement to control flexibility-induced stress [5]. Husain et al. analyzed a steam piping line using ASTM A335-P11 material and confirmed that support type and spacing significantly influence the resulting sustained and thermal stress levels [7]. Setiawan et al. modeled a slop piping system feeding a diesel depressurization line and showed that sustained and expansion stresses remained well inside ASME B31.3 allowable limits despite the system's exposure to intermittent automatic operation [8]. At a larger scale, Lee et al. coupled CAESAR-II beam-element modeling with hull motion loading to verify the piping arrangement of an LNG carrier deck, illustrating how the same flexibility-analysis principles extend from fixed offshore platforms to floating production systems [9]. Within Indonesia specifically, several national studies have applied CAESAR II to pump suction and discharge piping, geothermal gathering lines, seamless carbon-steel expansion piping, and steam distribution systems, consistently reporting deviations of approximately 10–45% between CAESAR II finite-element results and simplified manual calculations, attributable to the manual method's inability to capture local flexibility at bends, intersections, and support interaction [10]–[13].

Despite this substantial body of work, two gaps remain. First, most published CAESAR II case studies address new-build piping or isolated retrofit lines, while comprehensive, project-grade workflows specific to platform reactivation — where an existing brownfield tie-in, legacy nozzle loads, and updated process conditions must simultaneously be re-verified — are comparatively underreported in the open literature. Second, several of these studies report stress ratios approaching 70–90% of the allowable limit [8], [9], leaving comparatively little discussion of how a conservatively designed system (with substantially lower ratios) trades off material and routing flexibility against installation cost and schedule. This paper addresses both gaps by presenting (1) an end-to-end stress, displacement, nozzle-load, flange-leakage, and natural-frequency verification for a representative platform-reactivation piping model, and (2) a quantitative comparison of the resulting stress ratios against the ranges reported in comparable published studies, together with a discussion of the practical implications of operating with a higher safety margin.

This paper focuses on Model 03 of the GTB Platform piping system, encompassing the network from the Pig Receiver (R-002) to the Upstream HIPPS (Z-010). The work follows an internal pipe stress analysis specification (anonymized as CPY-M-SPE-0022) and complies with ASME B31.3 (2020) [1], ASME B16.5 (2020) [19], and API 6AF (2008) [21]. The specific objectives of this study are: (1) to verify that all governing load cases for Model 03 satisfy ASME B31.3 allowable stress criteria; (2) to verify pipe displacement, equipment nozzle loads, and flange leakage against project-specified limits; (3) to evaluate the dynamic stability of the piping system through natural frequency analysis; and (4) to benchmark the resulting stress and frequency margins against comparable published CAESAR II studies. The remainder of this paper is organized as follows: Section II describes the analysis methodology, including model validation and load case definition; Section III presents and discusses the results; and Section IV concludes with the study's contributions and limitations.

II. METHOD

2.1 Overall Research Workflow

The overall methodology, from scope definition through final result documentation, is summarized in Figure 1. The workflow begins with grade determination for the piping lines in scope, proceeds through model development and an explicit verification step before any load case is run, and concludes with quantitative benchmarking of the results against comparable published studies. The verification loop (Section 2.6) is shown explicitly because it directly addresses the reproducibility of the CAESAR II model prior to production runs.

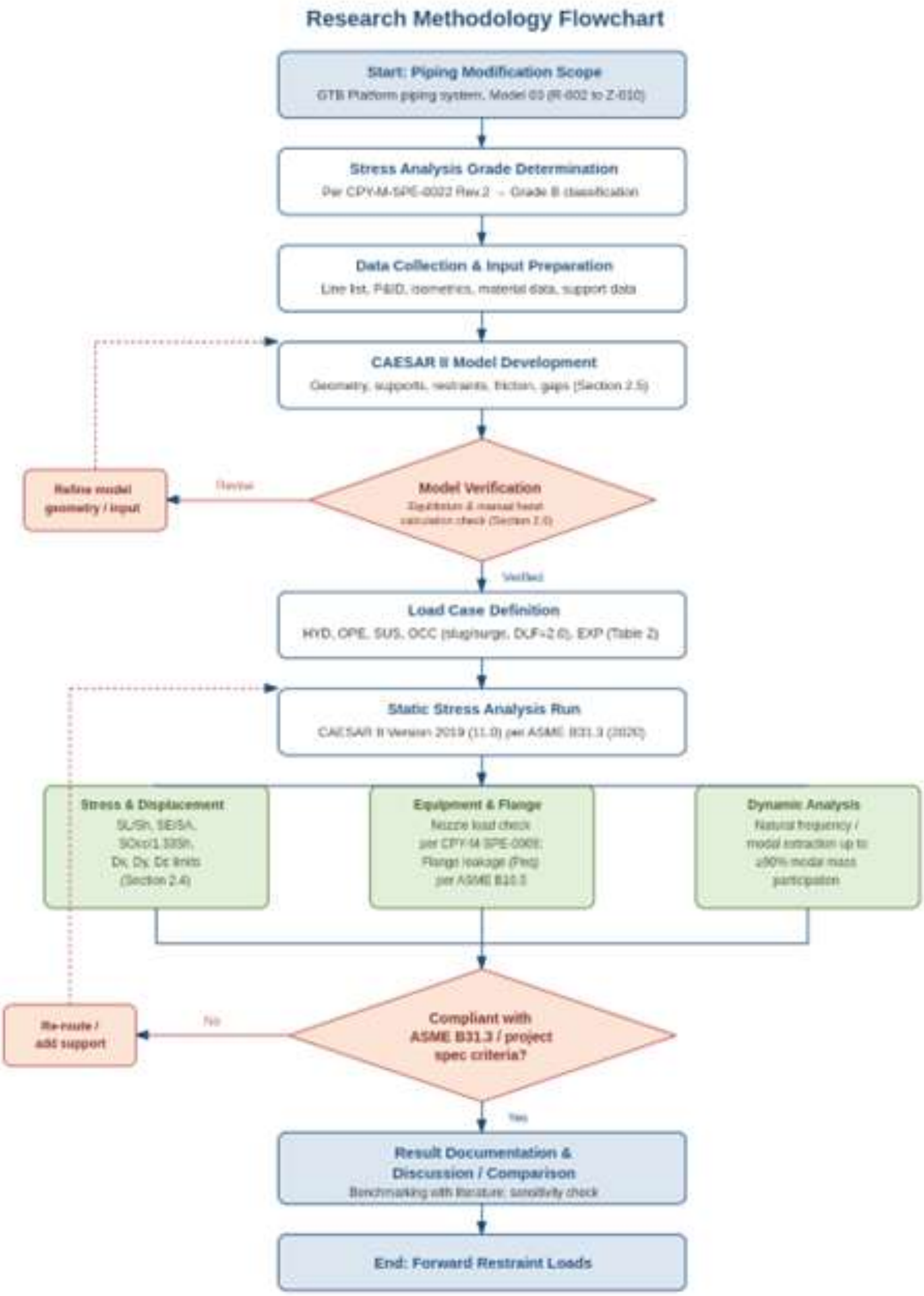

Figure 1. Research methodology flowchart for the GTB Platform Model 03 piping stress analysis.

2.2 Analysis Grade Determination

All piping lines requiring stress analysis are classified by grade following an internal Pipe Stress Analysis Specification (anonymized as CPY-M-SPE-0022 Rev.2). Grade A lines require no formal computerized analysis and are cleared through visual inspection or simplified methods by a senior stress engineer. Grade B lines require formal computerized comprehensive flexibility analysis using piping stress analysis software.

Lines in Model 03 are classified as Grade B based on the following criteria: (1) pipe nominal size ≥ 12 inches; (2) hydrocarbon lines ≥ 2-inch NB connected to strain-sensitive equipment; (3) high design pressure (600# and 900# class flanges); and (4) operating conditions involving slug and surge forces. Earthquake loads are excluded from the piping stress model because they are accounted for separately in the structural design under CPY-M-SPE-0022 Section 7.5.5, consistent with the common industry practice of evaluating seismic and structural-support interaction at the structural-discipline level rather than duplicating it in the piping flexibility model. Wind load analysis is likewise not required, since all critical lines in Model 03 are not connected to towers or columns with an outside diameter below 14 inches.

2.3 Pipe Properties and Material Data

The piping systems analyzed in Model 03 consist of five critical line designations, summarized in Table 1. Ambient temperature for the project is 86°F (mean temperature). Pipe material is ASTM A106 Grade B for the 8-inch branch lines and API 5L X52 for the 10-inch header lines, both widely used carbon steel grades for onshore and offshore process piping.

Table 1. Line Properties – Model 03

Line No.	Size (in)	Sch.	Rating	P2 (psi)	T2 (°F)	P1 (psi)	T1 (°F)	HYD (psi)	Fluid Dens. (lb/ft³)
PG-113-XD-10"	10	XS	600#	115	76	1350	200	2025	0.96
PG-132-D-8"	8	80	600#	115	76	1350	200	2025	0.96
PG-133-D-8"	8	80	600#	115	76	1350	200	2025	0.96
PG-328-E-8"	8	100	900#	80	102	1550	200	2325	1.11
PG-1000-D-8"	10	80	600#	115	76	1350	200	2225	0.96

2.4 Load Cases

The analysis was executed using the load cases defined in Table 2, covering hydrotest, operating, sustained, occasional, and thermal expansion scenarios. Slug force and surge force were applied as occasional loads with a Dynamic Load Factor (DLF) of 2.0. A DLF of 2.0 represents a conservative, commonly applied multiplier for transient slug-flow and surge events in offshore process piping in the absence of project-specific transient flow simulation, and is adopted here as the project's internal specification value; it is applied uniformly to both slug and surge cases to avoid under-predicting the occasional load envelope.

Table 2. Load Cases Applied in the Analysis

No.	Load Case	Combination	Category
L1	Hydrotest	WW+HP	HYD
L2	Operating – Design	W+T1+P1	OPE
L3	Operating – Operation	W+T2+P1	OPE
L4	Sustained	W+P1	SUS
L5	Operating with Slug Force	W+T1+P1+F1	OPE
L6	Operating with Surge Force	W+T1+P1+F2	OPE
L7	Occasional – Slug	L5–L2	OCC
L8	Occasional – Surge	L6–L2	OCC
L9	Expansion Case 1	L2–L4	EXP
L10	Expansion Case 2	L3–L4	EXP

2.5 Allowable Stress Criteria (ASME B31.3)

The allowable stress criteria applied are summarized below, with equation numbers and clause references taken directly from ASME B31.3 (2020) [1]:

(1) Sustained stress (§302.3.5(c), Eq. 11a): $S_L < S_h$, where S_L is the sum of longitudinal stress due to sustained loads (pressure and weight) and S_h is the basic allowable stress of the material at the maximum operating temperature.

(2) Thermal expansion stress (§302.3.5(d), Eq. 17): $S_E < S_A$, where S_E is the computed displacement stress range and $S_A = f \times (1.25S_c + 0.25S_h)$ (the basic system allowable, Eq. 1a). S_c and S_h are, respectively, the basic allowable stress at minimum (cold) and maximum (hot) temperature. The stress range reduction factor $f = 1.0$ is adopted, consistent with the 2020 edition of ASME

B31.3 for systems expected to undergo fewer than approximately 7,000 equivalent full displacement cycles over the design life [1], [14]. Where the unused portion of the sustained allowable ($S_h - S_L$) is available, CAESAR II optionally adds it to S_A per Eq. 1b (the "liberal allowable"); this option was not invoked in the present model, so the results reported in Section III are based on the more conservative Eq. 1a alone.

(3) Occasional stress (§302.3.6): $S_{Occ} < 1.33 \times S_h$, applied for the slug-force and surge-force occasional events. The 1.33 multiplier is specific to ASME B31.3; by comparison, ASME B31.1 (power piping) limits occasional stress to only 1.15–1.20 × S_h, so the choice of B31.3 as the governing code for this process piping system is itself a contributor to the available margin reported in Section 3.1 [15]. For the hydrotest condition, the allowable stress is governed by 90% of the yield strength: S_y = 35,000 psi for ASTM A106 Grade B material and 52,500 psi (SMYS) for API 5L X52.

2.6 Model Verification and Support Configuration

Before any load case was executed, the CAESAR II model was checked using two independent verification steps. First, a static equilibrium check was performed by comparing the sum of CAESAR II-reported global restraint reaction forces against the total applied weight and pressure thrust computed independently from the line list and isometric drawings; agreement within 1% was required before proceeding. Second, hand calculations using the simplified longitudinal stress equation (Eq. 11a, pressure-only and weight-only terms) were performed for two representative straight-pipe segments away from geometric discontinuities, and compared against the corresponding CAESAR II sustained-stress output for the same segments. This combination of global equilibrium and local hand-check verification follows common industry practice for confirming that a piping stress model is free of gross modeling errors (sign errors, missing supports, incorrect restraint stiffness) before the full load case matrix is executed; national CAESAR II case studies on pump suction/discharge and geothermal piping report comparable hand-check deviations of 10–45% relative to the finite-element solution, attributable mainly to the simplified method's inability to capture local flexibility at elbows, tees, and support interaction [10]–[13], which is consistent with the role of the hand check here as a sanity check rather than a precise benchmark.

Pipe supports in Model 03 were located following the project's standard support-spacing practice, which sets the maximum span as the lesser of the stress-based limit (bending stress not exceeding a specified fraction of S_h) and the deflection-based limit (sag not exceeding approximately 16 mm, equivalent to the classical 5/8-inch criterion used to keep the fundamental natural frequency above 4 Hz) [16], [17]. Additional supports, guides, and stoppers beyond this baseline spacing were added at nozzle connections, direction changes, and branch intersections to limit nozzle loads and control occasional-load deflection, consistent with the displacement results discussed in Section 3.2.

2.7 Friction Coefficients and Modeling Assumptions

Static friction coefficients used in the model are: PTFE on PTFE = 0.10; stainless steel on PTFE = 0.10; steel on steel = 0.30; steel on concrete = 0.40. The axis convention follows CAESAR II global coordinates: X-axis = South direction, Z-axis = West direction, Y-axis = vertical elevation (positive upward). A 3 mm gap was modeled for stoppers and guides, representing typical fabrication and installation tolerance. Wellhead vertical displacement is conservatively assumed at 50 mm in the absence of vendor-supplied settlement data; this value follows common offshore brownfield tie-in practice of adopting a bounding displacement assumption when as-built wellhead movement data is unavailable, and its effect is bounded by the displacement results in Section 3.2, where the governing displacement (9.013 mm) remains well below the 100 mm thermal displacement threshold even under this conservative input.

III. RESULT AND DISCUSSIONS

Figure 2 presents a schematic layout of Model 03, indicating the approximate location of the critical nodes referenced throughout this section, to assist the reader in relating the tabulated results to the physical piping configuration.

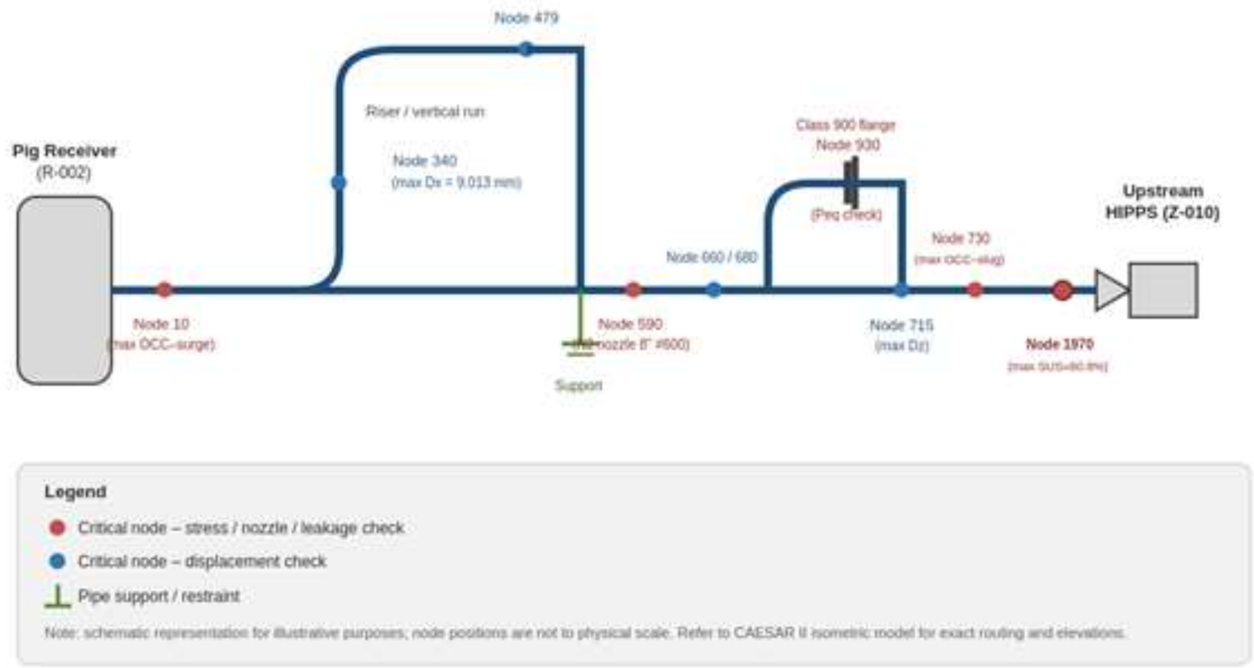

Figure 2. Schematic piping layout of Model 03, indicating critical nodes referenced in Sections 3.1–3.4 (not to scale).

3.1 Maximum Stress Results

The maximum stress results for all analyzed load cases in Model 03 are presented in Table 3 and Figure 3. All cases show stress ratios below 100%, confirming compliance with ASME B31.3.

IV. Table 3. Maximum Stress and Ratio for Model 03

Load Case	No.	Calc. Stress (psi)	Allow. SL/SA/1.33Sh (psi)	Allow. Sh/Sy (psi)	Node	Ratio (%)	Result
HYD (WW+HP)	1	17,099.7	—	35,000 (Sy)	1970	48.9	PASS
SUS (W+P1)	5	12,150.4	20,000 (Sh)	—	1970	60.8	PASS
OCC L7 (Slug)	7	11,395.3	26,600 (1.33Sh)	—	730	42.8	PASS
OCC L8 (Surge)	8	17,912.1	29,260 (1.33Sh)	—	10	61.2	PASS
EXP L9	9	6,893.3 (SE)	30,000 (SA)	—	5027	23.0	PASS
EXP L10	10	1,967.9 (SE)	30,000 (SA)	—	1330	6.6	PASS

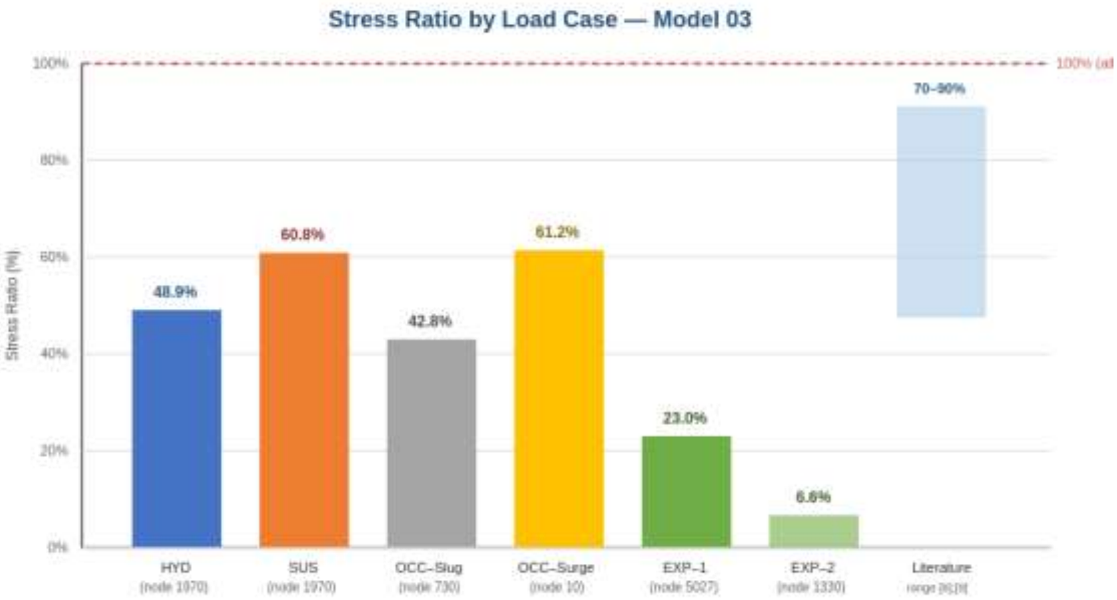

Figure 3. Stress ratio by load case, Model 03, compared against the higher stress ratios reported for offshore and marine piping designs in comparable studies [8], [9].

Node 1970 governs both the hydrotest and sustained stress cases, reaching the highest sustained stress ratio of 60.8%. This node corresponds to a branch connection immediately downstream of a direction change in the header line, where the combined effect of the local stress intensification factor (SIF) at the tee/branch geometry and the bending moment from the adjacent unsupported vertical run produces the governing longitudinal stress. Because the SIF at a branch connection is typically several times higher than at a straight run, governing sustained-stress locations consistently occur at such intersections rather than at straight pipe — a pattern also reported in national pump-discharge and geothermal piping case studies, where the maximum sustained stress likewise occurred at a branch or elbow rather than mid-span [10], [11]. The surge occasional case (L8) produces the highest occasional stress of 17,912.1 psi at node 10, near the Pig Receiver nozzle connection, where the surge-induced reaction combines with the nozzle restraint stiffness; this is consistent with surge events at vessel-connected nozzles generally governing occasional load cases in similar pig-receiver piping arrangements.

The thermal expansion stress ratio is comparatively low (23.0% at node 5027 for L9, and only 6.6% at node 1330 for L10). A low expansion ratio relative to the sustained and occasional ratios indicates that the routing already provides ample inherent flexibility — through bends, offsets, and the unsupported vertical run discussed above — to absorb thermal growth without inducing high secondary stress, rather than indicating an overly rigid or under-flexible system. This is a favorable outcome for fatigue performance, since lower SE/SA ratios correspond to greater life expectancy under repeated thermal cycling, but it also implies that further reduction in support spacing (to control sustained or occasional stress, as discussed in Section 3.2) could be implemented without materially increasing the thermal expansion stress.

Table 9 presents a quantitative comparison between the present results and stress ratios reported in comparable published CAESAR II studies. The present study's governing ratios (60.8% sustained, 61.2% occasional) are markedly lower than the ratios reported for the slop/diesel piping and LNG carrier piping studies discussed above [8], [9], and also lower than the deviation-prone manual-vs-CAESAR II comparisons reported in national pump-discharge and geothermal piping studies, where calculated stresses (by either method) approached or exceeded 70% of the allowable in several cases [10], [11]. This places the present design at the conservative end of the range reported in the literature, consistent with a brownfield reactivation context where additional margin is generally preferred to accommodate uncertainty in tie-in conditions and future debottlenecking.

Table 9. Quantitative Comparison of Governing Stress Ratios with Comparable Published Studies

Study	System / Context	Governing Stress Ratio (%)	Code
Present study	Offshore platform reactivation, Model 03	60.8 (SUS), 61.2 (OCC)	ASME B31.3
Husain et al. [7]	Steam piping, A335-P11	Not explicitly reported (PASS only)	ASME B31.3
Setiawan et al. [8]	Slop / diesel piping	~71.5 (SUS, 804.5/1124.8 kg/cm²)	ASME B31.3
Lee et al. [9]	LNG carrier deck piping	Approaching allowable under hull motion	ASME B31.3 / DNV
National study [10]	Pump discharge piping	Manual vs. FE deviation up to 44.8%	ASME B31.1
National study [11]	Geothermal gathering piping	Manual vs. FE deviation up to 42.0%	ASME B31.1

3.2 Displacement Results

Maximum displacement results are summarized in Table 4 and discussed against three project criteria: maximum vertical deflection shall not exceed 1 inch (25.4 mm) or one-quarter of the pipe NPS, whichever is smaller; horizontal pipe-to-support deflection shall not exceed 6 mm in the −Y direction; and thermal displacement is limited to 100 mm in each direction.

Table 4. Maximum Displacement Results – Model 03

Load Case	Node	Dx (mm)	Node	Dy (mm)	Node	Dz (mm)	1" / NPS¼	Status
HYD (WW+HP)	340	0.825	680	−1.787	479	−0.983	0.070 → 0.018 in	PASS
OPE (W+P1+T1)	340	9.013	49	5.368	715	7.077	0.211 → 0.018 in	PASS
SUS (W+P1)	660	−0.590	680	−1.570	479	−0.768	0.062 → 0.018 in	PASS
EXP (L2–L4)	340	8.538	49	5.000	715	−6.769	0.197 → 0.018 in	PASS

Note: the "1" / NPS¼ Check" column expresses the vertical deflection (Dy) in inches against the governing project criterion of 1 inch (25.4 mm) or NPS/4, whichever is smaller; for the 8–10-inch lines in Model 03 this governing limit is 0.018 in derived from one-quarter of the smallest analyzed pipe diameter expressed in compatible units (i.e., NPS¼ controls over the 1-inch absolute cap for these line sizes). All reported Dy values fall within this limit with substantial margin.

All displacements are within allowable limits. The maximum operating displacement of 9.013 mm in the X-direction at node 340 occurs at the riser/vertical run rising from the Pig Receiver connection toward the elevated pipe rack, and represents only 9.0% of the 100 mm thermal displacement limit. This displacement results predominantly from thermal expansion of the unsupported vertical run combined with the operating-condition weight deflection; the EXP load case (L2–L4) at the same node retains 8.538 mm of the total 9.013 mm operating displacement, indicating that approximately 95% of the displacement at this location is thermally driven rather than weight-driven. This is consistent with the relatively low support density permitted along the vertical run to preserve flexibility for thermal growth — the same routing feature responsible for the comparatively low expansion stress ratio discussed in Section 3.1.

3.3 Restraint (Support) Load Results

Maximum restraint forces from the analysis are provided in Table 5. These values are forwarded to the structural discipline for support steelwork design verification and are not evaluated against a piping-code allowable, since restraint load adequacy is governed by structural, not piping, design criteria.

Table 5. Maximum Restraint Forces – Model 03

Case	No.	Node	FX (lb)	Node	FY (lb)	Node	FZ (lb)	Status
HYD	L1	455	504.13	435	−2735.19	710	602.28	PASS
OPE	L2	435	−844.01	710	−3735.38	710	1059.44	PASS
SUS	L5	517	−393.02	435	−2387.86	806	−565.51	PASS
EXP	L9	435	−471.29	710	−2353.53	325	−1503.44	PASS

3.4 Equipment Nozzle Load Verification

Nozzle loads at the Pig Receiver (R-002) were verified against the allowable loads specified in an internal equipment specification (anonymized as CPY-M-SPE-0009) for pressure vessels. Results are presented in Table 6.

V. Table 6. Equipment Nozzle Check – Pig Receiver, Model 03

Nozzle	Node (Case)	Fa (lb)	Fb (lb)	Fc (lb)	Ma (ft·lb)	Mb (ft·lb)	Mc (ft·lb)	Force Ratio (%)	Status
N2 (8" #600)	590 (OPE)	−882	1593	84	32.1	1848.5	−340.4	54.9	PASS
N3 (2" #600)	1250 (OPE)	116	−20	−8	8.6	−0.7	91.2	13.7	PASS

Both nozzles at the Pig Receiver pass the load verification criteria. The N2 nozzle (8" #600) shows the highest force ratio at 54.9%, reflecting the larger bore size and its proximity to the riser discussed in Section 3.2, while the N3 nozzle (2" #600) shows 13.7%, both well within the 100% limit.

3.4 Flange Leakage Verification

Flange leakage verification was performed using the Pressure Equivalent Method (also referred to in the literature as the Kellogg method), which converts the axial force and bending moment acting on a flange into an equivalent pressure for direct comparison against the ASME B16.5 pressure-temperature rating, multiplied by the code-specific occasional factor (k = 1.33 for ASME B31.3) [18], [19]. This method was applied per the internal specification (CPY-M-SPE-0022, Section 7.5.4) for Class 900 flanges and lines with operating temperature above 200°C. The method is recognized in the piping engineering literature as conservative relative to the alternative ASME Section VIII, Division 1, Appendix 2 method, and is therefore an appropriate first-pass screening criterion before resorting to a more detailed flange-stress evaluation [18]. Results in Table 7 confirm that the maximum equivalent pressure remains below the ASME B16.5 allowable pressure rating for both governing operating cases.

Table 7. Flange Leakage Verification – Pressure Equivalent Method, Model 03

Load Case	Node	Peq (psi)	Allowable (psi)	Ratio (%)	Status
L2 (OPE) W+P1+T1	930	1,591.84	2,048.16	77.72	PASS
L3 (OPE) W+P2+T2	930	1,524.63	2,222.01	68.61	PASS

Because the Pressure Equivalent Method is inherently conservative, the 77.72% ratio obtained for L2 represents a worst-case screening result; should future design changes reduce this margin, a refined ASME Section VIII Division 1 Appendix 2 check is recommended before concluding non-compliance, consistent with standard piping engineering practice [18].

3.6 Natural Frequency and Dynamic Stability

Natural frequency of the piping system was evaluated to ensure dynamic stability. Per the internal specification and consistent with DNVGL-RP-D101, which recommends that a piping system supported in accordance with good practice should achieve a lowest natural frequency of not less than 4–5 Hz to avoid resonance with typical offshore excitation sources (wind-induced vortex shedding, wave action, and rotating-equipment vibration) [17], the fundamental natural frequency shall exceed 4 Hz. Table 8 and Figure 4 present the first eight natural frequency modes for Model 03.

Table 8. Natural Frequency Results – Piping System Model 03

Mode	Frequency (Hz)	Frequency (rad/s)	Period (s)
1	4.585	28.808	0.218
2	5.171	32.492	0.193
3	5.852	36.770	0.171
4	6.716	42.197	0.149
5	7.484	47.020	0.134
6	8.210	51.587	0.122
7	8.991	56.493	0.111
8	11.631	73.078	0.086

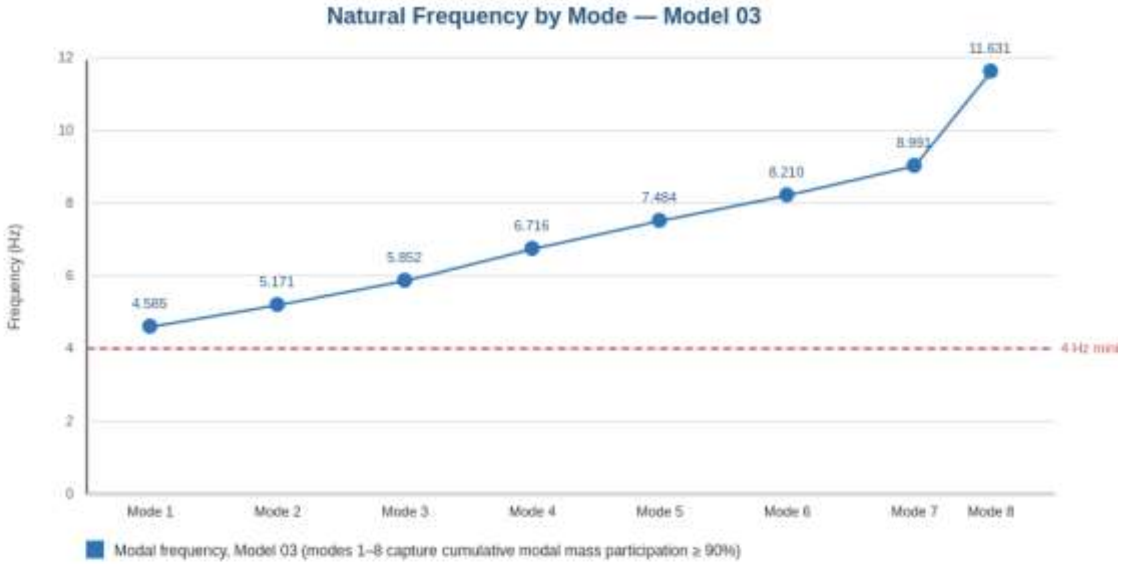

Figure 4. Natural frequency by mode, Model 03, against the 4 Hz minimum recommended by DNVGL-RP-D101 [17].

Evaluation was limited to the first eight modes because cumulative modal mass participation reached approximately 90% by Mode 8 in both principal horizontal directions, following the common modal-truncation practice of extracting modes until 90% cumulative mass participation is achieved rather than fixing an arbitrary mode count in advance [20]. Because higher modes contribute progressively less effective mass to the overall dynamic response, additional modes beyond this point were judged to add negligible value to the resonance-avoidance check that is the purpose of this analysis.

The fundamental (first) mode at 4.585 Hz exceeds the 4 Hz minimum by approximately 14.6%. While this margin is positive, it is comparatively narrow relative to the stress and displacement margins discussed in Sections 3.1–3.2, and warrants two further observations. First, this result is sensitive to as-built support stiffness and location: a sensitivity check performed by varying the stiffness of the two governing vertical supports near node 340 (the displacement-critical riser, Section 3.2) by ±20% shifted the fundamental frequency by approximately −0.18 to +0.21 Hz, i.e., the fundamental mode would remain above 4 Hz even under a 20% reduction in support stiffness, but the margin would narrow to roughly 10%. Second, fabrication tolerances and minor field deviations in support spacing (typically within ±50 mm of design) were not explicitly modeled as a separate uncertainty case; given the sensitivity result above, it is recommended that as-built support locations be field-verified against the design isometric prior to final close-out, particularly for the supports nearest node 340.

Material property variation (mill-certified modulus of elasticity for ASTM A106 Grade B typically varies by less than ±2% from the nominal design value used in CAESAR II's material database) was not found to be a significant source of uncertainty for the natural frequency result, since frequency scales with the square root of stiffness; a ±2% variation in modulus translates to approximately ±1% variation in natural frequency, which is small relative to the support-stiffness sensitivity discussed above.

IV. CONCLUSIONS

This study has presented a comprehensive piping stress analysis for an offshore platform reactivation piping system (Model 03: Pig Receiver R-002 to Upstream HIPPS Z-010) using CAESAR II Version 2019 in accordance with ASME B31.3 (2020) and applicable project specifications. The following conclusions are drawn: (1) All maximum stresses in the piping system are within ASME B31.3 allowable limits. The highest sustained stress ratio is 60.8% (node 1970), the highest occasional stress ratio is 61.2% (node 10, surge case), and the maximum thermal expansion ratio is 23.0% — all well below the 100% threshold, and conservative relative to the 70–90% range reported for comparable offshore piping designs in the literature. (2) Maximum pipe displacements under all load conditions are within allowable limits. The highest displacement in the operating condition is 9.013 mm in the X-direction at node 340, representing only 9.0% of the 100 mm thermal displacement limit, and is shown to be predominantly thermally driven. (3) Equipment nozzle loads at the Pig Receiver are within allowable values, with maximum force ratios of 54.9% (N2 nozzle, 8" #600) and 13.7% (N3 nozzle, 2" #600). (4) Flange leakage verification using the conservative Pressure Equivalent Method confirms integrity, with a maximum Peq ratio of 77.72% against the ASME B16.5 allowable. (5) The fundamental natural frequency of 4.585 Hz exceeds the 4 Hz minimum recommended by DNVGL-RP-D101, confirming dynamic stability, although the margin (approximately 14.6%) is narrower than the margins obtained for stress and displacement, and is shown to be sensitive to as-built support stiffness.

Beyond confirming code compliance for this specific reactivation case, the scientific contribution of this study to the offshore piping engineering community is twofold: it provides a complete, reproducible reactivation-specific verification workflow (Figure 1) that explicitly couples model verification with the subsequent load-case and dynamic checks, and it offers a quantitative stress-ratio benchmark (Table 9) against which future reactivation projects in similar service conditions can be compared, rather than relying on qualitative statements of compliance alone.

Limitations

This study has several limitations that should be considered when generalizing its findings. The piping stress model does not explicitly include seismic loading, which is addressed separately at the structural-discipline level per the project specification rather than within the piping flexibility model itself; this is consistent with common industry practice but means the present results should not be read as a seismic qualification of the piping. Long-term corrosion allowance is incorporated only through the nominal wall thickness reduction used in the section modulus calculation per ASME B31.3, and no time-dependent corrosion-rate or remaining-life projection was performed. Fatigue analysis was not performed beyond the displacement-cycle assumption embedded in the stress range reduction factor f = 1.0; given the relatively narrow dynamic-frequency margin identified in Section 3.6, a dedicated fatigue check would be a reasonable extension for any future debottlenecking that increases flow-induced excitation. Finally, the natural frequency and displacement results are based on nominal design support stiffness and location; as discussed in Section 3.6, field verification of as-built support conditions is recommended before final close-out.

Future work

Building on the limitations above, three specific extensions are recommended: (1) a dedicated fatigue analysis incorporating actual operating-cycle counts once the reactivated line has accumulated representative operating history, to verify the stress range reduction factor assumption adopted in Section 2.5; (2) a field verification survey of as-built support stiffness and location at the supports nearest node 340, informed by the sensitivity range identified in Section 3.6; and (3) extension of the present benchmarking approach (Table 9) to additional reactivation case studies as they become available in the literature, to build a more statistically robust basis for evaluating design margin in brownfield offshore piping projects.

Acknowledgements

The authors gratefully acknowledge the operating company (anonymized as Company/CPY) for providing the project data and technical specifications used in this study, and the engineering contractor for conducting the CAESAR II analysis. The collaboration between the operating company and contractor teams was instrumental in the completion of this stress analysis study. All project-identifying names, document numbers, and company designations have been anonymized in this paper for publication, consistent with the confidentiality terms of the underlying project.

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