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The Silent Collapse of North Sea Production: Fiscal Shock, Cascade Contagion, and the Infrastructure Decision Window

White Paper · Client edition of Working Paper No. 1 (V3) · not peer reviewed

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White Paper V10.2 · replaces V10.1 and V10 · survival results snapshot V15_6_20261008_075728_final

31 October 2026

Version note (White Paper V10.2, 31 October 2026)

This client edition replaces White Paper V9 (6 October 2026). It carries the findings of Working Paper No. 1 in the same structure, with a glossary for non-specialist readers, and adds Section 9 on the decommissioning evidence base. The survival results rest on analysis snapshot V15_6_20261008_075728_final (481 offshore fields, 10,173 field-years, 139 cessations). Panel counts, the 2024 closure rate and the scenario endpoints (151, 222 and 196 fields in 2032) were compared with the 24 October 2026 build record and agree.

V10.1 and V10.2 (31 October 2026): the reference list is corrected (OBR edition November 2022; OEUK, HMRC, NSTA and OSPAR titles as published; Hannan and Freeman under its published title; Cox pages 187–220; uncited references removed; Petroleum Act 1998, Infrastructure Act 2015 and SI 2015/398 added). Section 3.4 no longer withdraws the well-lag result, which Section 4.2 reports on oil-producing fields (HR 1.05). Section 8 now compares the HMRC cash receipts with the November 2022 OBR forecast of £26.0bn (shortfall about 65 per cent) and notes that part of the gap is gas-price error; the former full-period row (£65.7bn and £21.1bn) is removed pending a check against the March 2025 outlook. The unreferenced "NSTA I&E (2024)" row is removed from the data-sources table. No other results have changed.

Changes from V9: (1) the hub closure probabilities (the Forties Pipeline System band of 69 to 78 per cent, the period-specific table, and the FUKA and Flotta values) are withdrawn, because the canonical cascade sub-model script is not in the repository and the figures could not be reproduced from the audited feeder data (CCM V12 Technical Note V5, October 2026); audited feeder counts are reported instead; (2) the operator-level archetype permutation p-value is corrected from 0.50 to 0.48 (0.4833 on the 24 October build); (3) the Serica Energy figures are corrected to the Canonical Outputs Register (effective tax rate 63.8 per cent, replacing 176 per cent; dividend about 6.9 times the decommissioning provision of £18.8m, replacing 3.25 times); (4) Section 9 is new, and the former Section 9 is now Section 10.

Withdrawn from v8 and still withdrawn: the water cut hazard ratio of 2.522 and the Section 29 ratio of 3.421 (both depended on gas-only field-years that cannot record a closure); the decommissioning approval ratio of 6.528 and the well-lag ratio of 1.030; the two-year-lag EPL hazard ratio of 2.023; the 2024 closure rate of 8.49 per cent (now 7.46 per cent on a consistent denominator); the EPL excess of 5.55 percentage points (now about 4.7) and the 8.16 standard deviation figure; the Norpipe (99.8 per cent), FLAGS (100 per cent), FUKA (92.3 per cent) and CATS (45.1 per cent) probabilities; the claim that reform raises 0.9 billion pounds more revenue and the 40 to 55 per cent revenue-neutral rate; and the 2028 decision window. The definition of SFS is also corrected (see the glossary).

A water cut of 0.85 is used throughout as a statistical risk marker, not a limit of field viability. Results are exploratory associations and do not support causal claims.

Abstract

The UK Continental Shelf (UKCS) recorded its highest annual field Cessation of Production (CoP) rate in 2024: 7.46 per cent, with 22 of the 295 fields active at the end of 2023 permanently closing. This paper presents a survival analysis of the UKCS field population using the Meginráð Research master panel, covering 10,173 field-year observations across 481 offshore fields from 1975 to 2026, with 139 confirmed CoP events.

A Cox Proportional Hazards model on oil-producing field-years after 2010 (219 fields, 89 cessations) finds that fields at a water cut of 0.85 or above close at about twice the rate of other fields (hazard ratio 1.99, 95% CI 1.25 to 3.18; 0.85 is a risk marker, not a viability limit, and the rate keeps rising above it; the effect was very large in 2011 to 2015 and much smaller afterwards, although the two later periods cannot be told apart reliably when closures are resampled by operator, Section 4.6), and that each year without a development well adds about 5 per cent to the closure hazard (HR 1.05, 95% CI 1.01 to 1.08). Section 29 regulatory exposure points the same way (HR 1.43) but is not statistically significant, and drilling activity in the year is protective only at the margin (HR 0.13, p = 0.056). Gas-only fields are excluded because their closures are not coded in the outcome variable. Decommissioning programme approval cannot be estimated reliably because of data sparsity. A field-level Cox term for the Energy Profits Levy (EPL) cannot be identified: the lagged EPL rate is positive only in 2024 to 2026, and all 22 cessations in that window fall in 2024.

The EPL is therefore examined through a price-controlled Interrupted Time Series (ITS) counterfactual. The 2024 cessation rate is about 4.7 percentage points above the rate predicted from pre-EPL oil-price

behaviour, 2.7 times the predicted rate and 4.2 standard deviations above the pre-EPL mean of 2.46 per cent. This is consistent with an EPL effect, but the design has a short pre-period, a single treated unit and no control series, so it is evidence of association and timing, not proof of causation. A segmented regression on 21 annual observations (2004 to 2024) points the same way: a level fall of about 3 percentage points at 2022, followed by a rise of about 3 points a year. A cascade contagion model, a separate aggregation of field-level closure probabilities across shared pipeline infrastructure and not a Cox covariate, no longer yields reportable hub closure probabilities: the earlier figures (83.0 per cent for the Forties Pipeline System and 99.8 and 100 per cent for Norpipe and FLAGS, among others) could not be reproduced from the audited feeder data and are withdrawn, so this edition reports audited feeder counts only. Three scenarios to 2032 project 151, 222 and 196 active fields under continuation, EPL reform and managed transition respectively.

A second evidence base, a structured extraction of 363 public decommissioning documents filed with OPRED (203 decommissioning programmes, 70 environmental assessments, 55 comparative assessments and 35 close-out reports), is described in Section 9. It is descriptive: counts are of extracted documents, not of the UKCS. It supports a proposed check that the documents in a submission reconcile with each other and with statutory requirements before each decommissioning gate.

Keywords: survival analysis, Cox proportional hazards, North Sea, energy policy, decommissioning, cascade contagion, organisational ecology, fiscal policy, interrupted time series, decommissioning documents, document assurance

JEL Classification: Q41 (Energy: Demand and Supply) · Q48 (Energy: Government Policy, Regulation) · L71 (Mining, Extraction, Refining)

1. The UKCS in 2024: From Managed Decline to Accelerating Closure

1.1 A Basin in Crisis

The United Kingdom Continental Shelf has provided energy security, government revenue and high-skill employment for fifty years. At peak in 1999 it produced 2,626 thousand barrels of oil per day, and in 2000 gas production peaked at 1,018 terawatt-hours. By 2024, oil production had fallen by 78 per cent and gas production stood at 344 TWh, down 66 per cent from peak. The United Kingdom now imports 57 per cent of its gas consumption, having been a net exporter before 2004.

These aggregate statistics describe a mature basin in structural decline, a trajectory expected of any hydrocarbon province of the UKCS's vintage. What they do not reveal is the rate at which closures accelerated in 2024, nor the mechanism.

In 2024, twenty-two North Sea fields underwent Cessation of Production, an annual CoP rate of 7.46 per cent (22 of 295), the highest in the fifty-year record and 3.0 times the pre-EPL mean of 2.46 per cent recorded between 2015 and 2021. In 2022, the year the EPL was introduced, two fields reached CoP. In 2023, four. In 2024, twenty-two. This three-year sequence, two years of suppression followed by a cliff, is the pattern expected of a capital-starvation mechanism with a transmission lag, and it is the pattern the ITS analysis in Section 3 examines.

Every rate in this paper uses one convention: cessations in a year divided by the fields not ceased in the previous year (register ID RATE-10, standardised on 5 October 2026). Under the earlier mixed convention the 2024 rate was 8.09 per cent (22 of 272, the 2024 survivors); the standardised value is 7.46 per cent (22 of 295). 2024 is the highest rate on record under either.

1.2 What Is At Stake

The NSTA's own data identifies 19 billion barrels of oil equivalent recoverable within 50 kilometres of existing infrastructure, a resource base with a gross value exceeding 500 billion pounds at current prices. This resource is not inaccessible because it has been extracted. It is at risk because the infrastructure carrying it to shore is being decommissioned, not because the infrastructure has failed, but because the fiscal and commercial environment makes maintaining it uneconomic.

Beyond resource value, UKCS infrastructure is the physical backbone for committed energy transition pathways. The Acorn carbon capture and storage project depends on the Forties Pipeline System (FPS) and the St Fergus terminal. The Viking CCS project depends on Teesside. The Bacton Energy Hub depends on the Southern North Sea pipeline network. Each has a Final Investment Decision window in the 2025 to 2030 period. Infrastructure decommissioned before those decisions cannot be economically recommissioned.

1.3 The Analytical Gap

The existing literature on UKCS decline has characterised the basin's trajectory through production volumes, investment aggregates and policy analysis (Wood, 2014; NSTA, 2025; OEUK, 2024). None of these approaches provides a field-level survival analysis that identifies the independent contributions of geological, operational, governance and fiscal factors to the timing and rate of field closure. This paper addresses that gap, and is explicit about what the data can and cannot identify.

2. Data, Methods and Analytical Framework

2.1 The Master Panel

The panel is a field-year panel, one row per field per calendar year, constructed from nine primary data sources. It covers 10,173 observations across 481 offshore fields from 1975 to 2026, with 140 variables and 139 confirmed CoP events. Onshore fields are excluded.

Source	Variables contributed	Coverage
NSTA PPRS (monthly)	Production volumes, CoP events, water cut	1975–2026, 481 offshore fields
NSTA Well Register (May 2026)	last_well_spud_lag (years since last infill well)	91.4% post-2010
NSTA FDP Register (March 2026)	fdp_consent_year, fdp_lag_yrs_v2	91.7% coverage
OSPAR 2023 Inventory	plat_age_v14 (platform installation dates)	84% · 260 platforms
HMRC Historical Revenues (Sep 2025)	EPL outturn, PRT, RFCT, decommissioning relief	1964–2024
DESNZ DUKES (2025)	Gas production volumes, import dependency	1998–2024
NSTA Reserves & Resources 2024	2P reserves, reserves replacement ratio	Annual snapshots
Companies House (2024 accounts)	ARO provisions, ETR, dividends	12 operators

2.2 Cox Proportional Hazards Model: Specification

The Cox Proportional Hazards model (Cox, 1972) estimates the hazard ratio (HR), the multiplicative change in the instantaneous probability of an event (here, field CoP) associated with a unit change in a variable, holding the others constant. An HR above one indicates elevated closure risk; below one, reduced risk.

The primary specification uses oil-producing field-years after 2010, excluding the CATS pipeline system, which records no CoP events in the sample window. The outcome, event_cop, is coded for oil fields only; closures of gas-only fields are held in a separate and less reliable variable, so gas-only field-years are excluded from the risk set. An earlier version of this paper included them, and Section 4.4 shows that they distorted the results. Water cut enters as an indicator for a level of 0.85 or above, the programme's established high-risk threshold; the linear form is reported as a sensitivity. The other four predictors are drilling activity in the year, Section 29 exposure, years since FDP consent and years since the last

development well. Ties are handled by the Efron method and standard errors are clustered at the field level. The model is not stratified. Decommissioning programme approval and an EPL term are deliberately excluded for the reasons given in Sections 3 and 4.2.

Model parameter	Value	Note
Sample	Oil-producing, post-2010, non-CATS	2,789 field-years, 248 fields; gas-only field-years excluded
Estimation sample	2,448 field-years, 219 fields	Complete cases on all five predictors
CoP events	89	95 before missing-covariate exclusions
Events per variable	17.8	89 events / 5 predictors
Standard errors	Clustered by field	Not clustered by operator; see Section 10.3
Wald chi2(5)	28.30, p < 0.001	Threshold specification
Log pseudolikelihood	-428.29	Stata 16.1, 7 October 2026 (17_cox_time0_rerun.do)

2.3 Theoretical Framework: Hannan-Freeman Organisational Ecology

The era stratification and operator analyses draw on Hannan and Freeman's (1989) organisational ecology framework, modelling populations of organisations as biological populations subject to founding, mortality, density dependence and ecological succession. The field is the organism-equivalent; the operator is the selective environment. Unlike biological populations, fields cannot reproduce: founding is determined by exploration success and FDP consent, not density-dependent imitation. This disanalogy is acknowledged explicitly.

- Density dependence: the inverted-U relationship between population size and founding and mortality rates (peak of 361 fields in 2016, a figure from the earlier panel that is being recomputed).
- Liability of obsolescence and imprinting: the hypothesis that operators whose business plans were set under a 40 per cent tax regime are structurally mismatched to a 78 per cent regime. This is a hypothesis, tested at operator level in Section 6.2 and in Working Papers 3 and 4, where the evidence to date is not robust.

3. The EPL: Identification and the Interrupted Time Series

3.1 The Identification Problem

Attributing field mortality to the EPL, rather than to concurrent oil price movements or geological depletion, requires a credible identification strategy. A field-level Cox term for the EPL does not provide one. The EPL rate is a step function of calendar year (0 before 2022, 25 per cent in 2022, 35 per cent in 2023, 38 per cent from 2024), so a two-year-lagged EPL rate is positive only in 2024, 2025 and 2026. Across 775 field-years in that window there are 22 cessations, all of them in 2024; none is recorded in 2025 or 2026, which may partly reflect reporting lag in the most recent years. Any lagged-EPL coefficient is therefore identified by a single year and cannot be separated from anything else that changed in 2024.

The empirical record bears this out. In the extended model the lagged-EPL coefficient has no estimable standard error, and its hazard ratio moves from 1.14 to 6.11 depending on which other covariate is included (an earlier panel gave a value below 1). The raw cessation rate is 2.8 per cent in the lagged-EPL window (22 of 775 field-years) against 1.7 per cent before it (73 of 4,227). A previously reported lagged-EPL hazard ratio of 2.023 has been withdrawn on these grounds. The contemporaneous EPL term is likewise not

estimable as a separate effect for the same reason. The EPL question is therefore addressed with a design that does not rely on a field-level coefficient.

3.2 The Interrupted Time Series Method

An Interrupted Time Series (ITS) analysis separates the EPL's effect from concurrent oil price movements in three steps: first, establish the pre-intervention relationship between oil price and the annual CoP rate using only pre-EPL data; second, project what the rate would have been after the EPL using that relationship and actual post-EPL oil prices; third, compare the projection with the observed rate. The design follows Bernal, Cummins and Gasparrini (2017).

3.3 The Price-Controlled Counterfactual

Across 2015 to 2021 (n = 7, full panel) the correlation between the Brent price and the annual CoP rate is r = +0.14, so oil price explains under 2 per cent of the variance in pre-EPL field mortality. The pre-EPL regression is CoP rate = 1.64 + 0.0142 x Brent. Applied to the 2024 average price of $79.91 per barrel it predicts a rate of 2.77 per cent. The observed rate was 7.46 per cent: an excess of about 4.7 percentage points, 2.7 times the predicted rate, and 4.2 standard deviations above the pre-EPL mean of 2.46 per cent (SD 1.20).

Year	Brent $/bbl	CoP rate observed	CoP rate price-predicted	Residual	Reading
2022	$99.00	0.67%	3.04%	-2.37 pp	Below prediction
2023	$82.32	1.36%	2.81%	-1.45 pp	Below prediction
2024	$79.91	7.46%	2.77%	+4.68 pp	Above prediction (cliff)

Source: ITS annual series, 2015 to 2021 pre-period, full panel including CATS (register RATE-04 basis). Percentages are given to the precision supported by seven pre-period observations.

The 2022 and 2023 rates fall below the price-predicted rate and the 2024 rate far above it. This is consistent with deferral of closures followed by a cliff, as would follow if the EPL froze investment decisions in 2022 and the effect on cessation arrived with a lag. It is also consistent with other explanations that coincide with 2024.

3.4 What the Design Can and Cannot Show

The ITS estimate rests on seven pre-period annual observations, a single treated unit (the basin) and no control series; only one post-EPL year lies above the prediction; and the price relationship is weak, so the counterfactual is close to the pre-EPL mean. It is evidence that the 2024 cliff is not explained by oil price and that its timing is consistent with the EPL escalations, not proof that the EPL caused it. Corroboration at field level is limited, but not absent: the earlier all-field estimate of no effect of years since the last development well (HR 0.998, p = 0.91) reflected gas-only field-years that cannot record a closure; on oil-producing fields each year without a development well adds about 5 per cent to the closure hazard (HR 1.05, p = 0.005; Section 4.2).

3.5 A Segmented-Regression Check

As a check that does not rely on the counterfactual's seven-point pre-period, the annual cessation rate was also fitted as a segmented regression (Bernal, Cummins and Gasparrini, 2017) on the 21 observations from 2004 to 2024, using Newey-West standard errors with two lags and the Brent price as a control. The post-EPL terms are centred on the intervention year, so the first coefficient is the level change at 2022 and the second is the change in slope for each year afterwards.

Specification	Level change at 2022 (pp)	Slope change per year after (pp)	Control

Primary (with Brent)	-3.00 (SE 0.76, p = 0.001)	+3.15 (SE 0.65, p = 0.0002)	Brent -0.009 (p = 0.41)
With log UKCS capex	-3.81 (SE 0.86, p = 0.0005)	+3.39 (SE 0.64, p = 0.0001)	Capex -0.98 (p = 0.11)

Source: its_epl_causal_identification.do, run of 6 October 2026 (n = 21, 16 degrees of freedom). The series uses the standardised prior-year denominator.

The pattern agrees with the counterfactual: cessation rates fell below trend when the levy was introduced and then rose steeply, so that by 2024 the rate sits well above the pre-EPL path. It is a robustness check, not independent proof. Three post-EPL observations carry the slope term, so it largely reflects the 2024 rise, and the standard errors are approximate. A dose-response specification with separate terms for the 2022 and 2023 escalations cannot separate the three post-EPL years and is not reported.

4. Primary Model Results and Robustness

4.1 Hazard Ratios

Variable	HR	95% CI	p	Interpretation
wc_hi85 (water cut 0.85 or above)	1.994	1.252 to 3.177	0.004	Fields at or above the threshold close at about twice the rate of others.
drill_yr	0.134	0.017 to 1.050	0.056	Drilling activity in the year is protective, but the interval reaches 1. A proxy for any drilling.
section29_high	1.427	0.921 to 2.211	0.112	Points towards higher hazard but is not statistically significant.
fdp_lag_yrs_v2	0.992	0.967 to 1.016	0.499	No detectable effect of years since FDP consent.
last_well_spud_lag	1.048	1.014 to 1.084	0.005	Each year without a development well adds about 5 per cent to the hazard.

N = 2,448 field-years, 219 fields, 89 cessations. Oil-producing field-years, post-2010, non-CATS. Efron ties, standard errors clustered by field. Wald chi2(5) = 28.30. Log pseudolikelihood = -428.29. Stata 16.1 run of 7 October 2026.

4.2 Key Findings by Variable

Water cut acts as a threshold. A field at a water cut of 0.85 is producing 85 barrels of water for every 15 barrels of oil, and each barrel must be separated, treated and disposed of at fixed cost. Oil-producing fields at or above 0.85 close at about twice the rate of others (HR 1.99, 95% CI 1.25 to 3.18): the crude rates are 5.3 per cent a field-year at or above the threshold and 2.6 per cent below it. The linear effect is weaker and not significant (HR 1.55, p = 0.32), which indicates that risk rises sharply near the threshold and not smoothly with water cut. Of 157 oil-producing active fields in 2024, 51 (32 per cent) are at or above 0.85. Earlier drafts counted 102 of 272, but half of those were gas-only fields with a water cut of 1.0 by construction. The earlier EPL-era subgroup estimate (HR 5.98) came from the earlier sample and is withdrawn. On oil-producing fields the estimate is 2.26 from 2022 onward (28 closures) and 1.75 before (66 closures) (Section 4.5), and it differs across three periods, though less securely than field-clustered errors suggest (Section 4.6).

Note on the 0.85 threshold. A water cut of 0.85 is a statistical risk marker in this analysis, not a limit of field viability. On the UKCS many mature fields operate profitably well beyond it, and the economic cut-off typically lies nearer 90 to 98 per cent. Where it falls depends on produced-water handling capacity (separation, treatment, reinjection and discharge limits), on operating cost against the oil price, on the difference between a well-level and a field-level cut-off, and on artificial lift. An 85 per cent water cut marks the point where water-handling costs begin to accelerate; it is not a regulatory or economic termination benchmark. In this data the closure rate keeps rising above 0.85. Among oil-producing field-years the crude

rate is 2.6 per cent a field-year below a water cut of 0.5, about 4 per cent between 0.85 and 0.95, and 8.2 per cent at 0.95 or above. The hazard ratio for an indicator at a higher threshold is larger, and fit is best at 0.90, so 0.85 is the conservative end of a gradient. It is retained as the headline because it is the programme's established high-risk marker and was not chosen to fit.

Indicator threshold	Hazard ratio	Log-likelihood	Reading
0.80	1.59	-430.83	Weaker
0.85 (headline)	1.99	-428.29	Programme marker
0.90	2.40	-426.44	Best fit
0.95	2.94	-427.58	Few fields above

Source: 17_cox_time0_rerun.log, block G2, Stata 16.1, 7 October 2026. Field-clustered standard errors; each row is the same model with a different indicator threshold.

Section 29 exposure (HR 1.43, 95% CI 0.92 to 2.21, p = 0.112) points towards a higher closure hazard but is not statistically significant on oil-producing fields. An earlier estimate of 2.56 depended on the gas-only field-years. Section 29 of the Petroleum Act 1998 allows the regulator to require a former interest holder to contribute to decommissioning costs regardless of when they divested; the statutory basis is Section 30's back-chain test specifically. In the levy era alone the estimate is 2.91 (95% CI 1.34 to 6.36), against 1.04 before 2022, and the interaction is significant (p = 0.030); this rests on 28 closures and is exploratory (Section 4.5). The exposure measure is a proxy built from operator type and field age and has not been validated against the licence transfer register.

Decommissioning programme approval is not in the primary model. It applies to only 31 field-years in the estimation sample, all in 2024 to 2026 and so coincident with the EPL era. In any model that also includes the EPL rate it produces quasi-complete separation (hazard ratios of order 10^-18). It is reported here as a descriptive indicator of imminent closure, not as an estimated hazard ratio. The earlier figure of 6.528 is withdrawn.

Drilling activity in the year is protective (HR 0.13) but the interval includes 1 (0.02 to 1.05; p = 0.056), and the variable is a proxy for any drilling activity in the field. It is consistent with active investment lowering closure hazard, and it should not be read as precise.

Years since the last development well add about 5 per cent a year to the closure hazard (HR 1.05, 95% CI 1.01 to 1.08, p = 0.005). The earlier estimate of no effect (0.998) reflected the gas-only field-years. The result is consistent with a capital-starvation mechanism, in which fields where drilling has stopped close more often.

A note on the hub covariates. An earlier draft reported the hub decommissioning share at HR 3.104 (p < 0.001). The corrected panel did not reproduce it, and the hub covariates are not in the current primary model. The cascade risk finding in Section 5 rests entirely on the separate hub-level aggregation model, not on a Cox hazard ratio, and should be cited accordingly.

4.3 Proportional Hazards Assumption

Proportional hazards were tested on the oil-producing threshold model (Stata, 7 October 2026). The global Schoenfeld test is borderline (chi2(5) = 10.44, p = 0.064). The water cut indicator on its own violates the assumption (rho = -0.19, chi2 = 4.29, p = 0.038); the other four covariates do not (p from 0.08 to 0.68). The hazard ratio of 1.99 is therefore a time-averaged effect, and Section 4.6 shows how it changes over time.

In the Forties-only subgroup of oil-producing fields (33 closures, 102 fields) the water cut indicator is not significant (HR 1.15, 95% CI 0.52 to 2.52, p = 0.74), while each year without a development well adds about 8 per cent (HR 1.08, 95% CI 1.02 to 1.13, p = 0.006). Within Forties the data cannot confirm the pooled water cut effect, so any hub-level result that applies it would be conditional on that effect holding on the system.

4.4 Why the Sample Excludes Gas-Only Fields

The outcome variable, event_cop, records cessations of oil fields. Closures of gas-only fields sit in a separate variable (event_cop_gas) that is less reliable, with a false-positive rate of about 24 per cent. The earlier sample nevertheless included gas-only fields: 2,213 of its 5,002 field-years (44 per cent) had no oil production and none records a cessation. Of those, 695 have a water cut of exactly 1.0, because water divided by water plus oil is 1.0 for any trace of water when there is no oil, and the rest have a water cut of 0. They entered every risk set as observations that could not fail, with extreme water cut values.

Specification	Water cut	Section 29	Well spud lag
All field-years (earlier version)	2.38 (1.35 to 4.20), p = 0.003	2.56 (1.65 to 3.96), p < 0.001	0.998, p = 0.91
Oil-producing, linear water cut	1.55 (0.65 to 3.66), p = 0.32	1.39 (0.89 to 2.17), p = 0.15	1.05 (1.02 to 1.08), p = 0.004
Oil-producing, 0.85 threshold (primary)	1.99 (1.25 to 3.18), p = 0.004	1.43 (0.92 to 2.21), p = 0.112	1.05 (1.01 to 1.08), p = 0.005

Source: 04_cox_model.log (all field-years) and 17_cox_time0_rerun.log (oil-producing rows), Stata 16.1, 6 and 7 October 2026. Same clustering in each row; the oil-producing rows use the corrected record intervals (Section 4.4).

The earlier results were therefore partly a comparison of oil fields with gas fields. On oil-producing field-years the linear water cut effect and Section 29 lose significance, the well-spud lag becomes significant, and the water cut effect appears as a threshold. Because the specification was changed after the problem was found, the threshold result should be treated as confirmed only after replication on independent data. A model of gas-field closure needs its own risk drivers, since water cut is not defined for a field with no oil; an exploratory model is reported in Section 4.5.

A second specification error was found and corrected on 7 October 2026. The earlier Stata runs fixed only the time at which a field enters the analysis, so Stata built each record as running from the field's previous row to the current year. Restricting to oil-producing years removes a field's zero-oil years and leaves gaps (59 rows follow a gap), and across a gap Stata treated the field as at risk, using the later row's covariates. A field with no oil in a year cannot record an oil closure. The correction fixes every record at one year, from year minus one to year. It removes the dependence of the estimates on whether 2025 and 2026 are included, which was the symptom that exposed the error; the 2025 and 2026 rows themselves carry no information, because no closures are flagged in them and a closure can be recorded only once the following year shows no production. The changes are small: the primary hazard ratio moved from 2.005 to 1.994, the 0.90 and 0.95 thresholds from 2.30 and 2.66 to 2.40 and 2.94, and the first-period estimate in Section 4.6 from 23.2 to 19.3. The corrected figures agree with an independent Python replication that treats every row as one year.

4.5 Extended checks on oil-producing field-years

Four further checks were run on oil-producing field-years after the sample correction (Stata, 7 October 2026, with the record intervals corrected as described in Section 4.4). The table splits the threshold model by period and to Forties alone, each with three covariates.

Subsample	Closures	Water cut at or above 0.85	Section 29 high exposure	Years without a well
Before the levy (2011 to 2021)	66	1.75 (1.03 to 2.96)	0.93 (0.54 to 1.62)	1.08 (1.04 to 1.12)
Levy era (2022 onward)	28	2.26 (1.08 to 4.74)	3.02 (1.34 to 6.83)	1.03 (0.98 to 1.08)
Forties only	33	1.15 (0.52 to 2.52)	1.06 (0.50 to 2.28)	1.08 (1.02 to 1.13)

Source: 13_cox_oil_only_extended.log, blocks E2 and E3, Stata 16.1, 7 October 2026 (corrected record intervals). Hazard ratios with 95% confidence intervals; field-clustered standard errors.

A pooled model with a Section 29 by levy-era interaction gives an interaction hazard ratio of 2.82 (95% CI 1.11 to 7.16, p = 0.030). Section 29 exposure carries a hazard ratio of 2.91 in the levy era (1.34 to 6.36) and 1.04 before it (0.60 to 1.77). This is consistent with back-chain liability becoming a closure risk when margins are squeezed, but it rests on 28 closures and was found by comparing periods, so it is exploratory. Under the operator bootstrap the levy-era estimate is 2.91 (interval 0.85 to 18.3) and the interaction 2.81 (0.55 to 88.8). The levy-era main effect cannot be estimated separately because the baseline hazard is defined on calendar time.

A log-rank test across the four archetypes with events, on oil-producing field-years with calendar time, finds no difference (chi2(3) = 5.12, p = 0.16; observed against expected closures: IOC 38 and 40.7, large public independent 17 and 19.0, PE-backed 32 and 31.4, small new independent 8 and 3.9).

Gas-only fields were modelled separately with the gas closure outcome (63 closures, 2,030 field-years, 266 fields), using prior-year values to limit circularity. Prior-year gas output has a hazard ratio of 0.42 per log unit (95% CI 0.34 to 0.53, p < 0.001) and the prior-year fractional decline 1.75 (1.22 to 2.53, p = 0.003). Platform age (0.95, p = 0.71), years since the last well, Section 29 and consent age show no detectable effect. Low and falling output marks the marginal gas feeders. Because the gas outcome is inferred from a shut-in pattern, with a false-positive rate of about 24 per cent, these production effects are partly mechanical. Once produced water volume was restored to the panel, a prior-year water-to-gas ratio was added (Stata, 8 October 2026; 56 closures, 236 fields). Its level is protective (hazard ratio 0.88 per log unit, 95% CI 0.79 to 0.99, p = 0.027), the opposite of the idea that water handling marks marginal feeders, and output stays strongly protective (0.34, 0.26 to 0.44). The prior-year fractional decline loses significance (1.25, p = 0.29). A prior-year rise in the ratio raises the hazard (1.29, 1.02 to 1.63, p = 0.034), but this is partly mechanical because the ratio rises when gas output falls. Most gas field-years report no produced water (the median ratio is zero), so the ratio is informative only for a minority of fields. The gas model therefore remains a screening result and does not support hub probabilities.

4.6 The Water Cut Effect Changes Over Time

The pooled hazard ratio is an average over very different periods. A model in which the water cut effect changes linearly with calendar time gives a multiplier of 0.86 a year (95% CI 0.76 to 0.98, p = 0.019), implying a hazard ratio of 6.2 in 2012, 3.4 in 2016, 1.9 in 2020 and 1.0 in 2024. A model with a separate effect in each of three periods shows where the change occurs.

Period	Hazard ratio (95% CI)	Closures	Share of closures at high water cut / share of field-years at high water cut
2011 to 2015	19.3 (4.3 to 86.4)	18	83% / 29%
2016 to 2021	0.90 (0.44 to 1.84)	49	27% / 27%
2022 to 2024	2.40 (1.11 to 5.19)	28	57% / 35%

Source: 17_cox_time0_rerun.log (block G4), Stata 16.1, 7 October 2026; closure counts from the crude rates in 15_cox_tvc_oil_only.log. Field-clustered standard errors.

With errors clustered by field, the test that the effect is the same in all three periods is rejected (Wald chi2(2) = 14.11, p = 0.0009); operator-level inference is reported below. The effect was very large in 2011 to 2015, when 15 of 18 closures were of fields at high water cut. It was not detectable in 2016 to 2021 (0.90), when closures in 2020 and 2021 were mostly of low water cut fields (crude closure rates of 8.0 and 7.7 per cent, well above their earlier average), a pattern that looks like price and demand shocks and not depletion. The point estimate is 2.40 again in 2022 to 2024, driven by 2024, when 21.9 per cent of high water cut field-years ended in closure against 7.8 per cent of the rest. The difference between 2016 to 2021 and 2022 to 2024 is suggestive but not firm (p = 0.064), and a model with only a levy-era interaction finds no significant difference between the levy era (2.41) and before it (1.84; interaction p = 0.58). The first-period estimate is very imprecise.

Operator-level inference. Closures are concentrated: in the oil-producing sample the 89 closures fall among 19 operators, four of which have none, and three (NEO NEXT+, EnQuest and TAQA) account for 47 (53 per

cent). Standard errors clustered by field may therefore understate uncertainty. A cluster bootstrap over operators (2,000 resamples; a ridge penalty of 0.02 on all coefficients keeps resamples with no closures in drilling years estimable and moves the point estimates by under 0.5 per cent) gives a 95 per cent interval of 1.22 to 3.01 for the pooled effect, against 1.25 to 3.18 with field clustering, and 99.4 per cent of resamples lie above 1. Dropping any single operator leaves the pooled hazard ratio between 1.80 and 2.21, and dropping the three largest contributors leaves 1.75 on 42 closures. The period pattern is less secure. The 2011 to 2015 effect exceeds both later effects in more than 99.9 per cent of resamples, but the 2016 to 2021 effect (0.90, interval 0.25 to 1.49) and the 2022 to 2024 effect (2.39, interval 0.92 to 5.77) cannot be separated reliably: the second exceeds the first in about 95 per cent of resamples, with a ratio of 2.6 (interval 0.8 to 16.6). A Wald test of equal effects based on the bootstrap covariance gives p = 0.17, against 0.0009 with field clustering; it is conservative, because the 2011 to 2015 estimate is very imprecise. What survives operator-level inference is that the effect was largest in 2011 to 2015, not that it was absent in 2016 to 2021 and present again after 2022.

Two consequences follow. A single hazard ratio should be quoted as an average, with the period pattern beside it. And any hub-level result that applies one water cut effect to every feeder (Section 5) is conditional on that effect holding, which is one reason hub probabilities are not reported in this edition.

5. The Cascade Contagion: Hub Systems and Their Downstream Consequences

5.1 The Cascade Mechanism

UKCS production flows through major trunk pipeline systems, each functioning as a hub: satellite fields feed a shared trunk pipeline to a single onshore terminal whose economics are substantially fixed regardless of throughput. When fields close and throughput falls, cost per barrel transported rises, making the next most marginal field uneconomic. It closes, throughput falls further, and the process repeats until the terminal's minimum viable throughput is breached, stranding the remaining satellite fields regardless of individual reservoir economics.

The cascade model aggregates field-level closure probabilities across the live feeders of each system. Earlier editions used it to report a closure probability for each hub. Those figures are not reported in this edition: the canonical sub-model script is not in the repository, the figures could not be reproduced from the audited feeder data (CCM V12 Technical Note V5, October 2026), and they applied one water cut effect to every feeder when that effect changes over time (Section 4.6). This edition reports audited feeder counts only.

5.2 System Results

Pipeline system	Active fields 2024	Live feeders (audited)	Closure probability	Note
FPS (Forties)	81	66 (oil)	Not reported	19 of 66 live feeders are at or above a water cut of 0.85 (13 at 0.90, 7 at 0.95). Critical for the Acorn CCS project. The earlier 83.0 per cent and the 69 to 78 per cent band are not reported.
FUKA (gas, to St Fergus)	20	13 (gas)	Not reported	3 of 13 audited feeders are at or above 0.85. The earlier 92.3 per cent used an unaudited list of 58 live fields and is withdrawn.
Norpipe (oil, to Teesside)	3	7 (oil)	Not reported	1 of 7 live feeders is at or above 0.85. The earlier 99.8 and 67.6 per cent traced to 74 legacy-tagged fields (see 5.3). Norpipe also

				carries Norwegian-sector volumes, so UK feeders alone do not set its viability.
FLAGS / West of Shetland	9	2 (gas)	Not reported	Both feeders are at or above 0.85. A count only: viability depends on bulk export volumes and St Fergus gas specifications, not field tallies. Finch consent freeze in effect. The earlier 100 per cent is not reproducible.
CATS	13	n/a	Not modelled	No cessations since 2010, so the baseline hazard is undefined. The earlier 45.1% is withdrawn.

Active fields: current panel, event_cop = 0 in 2024, after normalising raw pipeline names. Live feeders: the audited population rule (producing in the last two years). Feeder counts: CCM V12 Technical Note V5 (October 2026) and the 5 October 2026 reconciliation.

5.3 Norpipe: Feeder Attrition, Not a Probability

Norpipe recorded zero field CoP events in recent years, so by observed events it looks healthy, yet earlier versions of this paper gave it the highest cascade probability in the network, 99.8 per cent, because 67.6 per cent of its feeder fields were at or above the 0.85 water cut threshold. Both figures trace to the legacy pipeline tagging. The original panel tagged 74 live fields to Norpipe, and 50 of them (67.6 per cent) had water cut at or above 0.85. A September 2026 audit found that 76 of the 83 legacy Norpipe tags were Southern North Sea gas fields that do not feed Norpipe. Both figures are therefore withdrawn.

On the audited population Norpipe has seven live oil feeders, one of them at or above 0.85. A probability computed from so few fields would carry little information, so only the live feeder count is reported. A feeder count is an imperfect proxy for what governs a shared pipeline, which is volumetric throughput, tariff economics and fixed operating cost, and Norpipe also carries Norwegian-sector volumes that the UK panel does not measure. The count therefore indicates a rising unit-tariff burden and cost concentration on the remaining feeders. It does not show that an engineering minimum has been breached. Establishing physical minimum volumes is an engineering question for a later model phase.

5.4 The CCS Collision

Earlier versions of this paper gave cascade timing of around 2029 for FPS and 2030 for Norpipe, and described a 2028 decision window. Those years came from applying minimum-feeder-count thresholds, which are unratified engineering estimates, to feeder populations that the 2026 audit has superseded. Applied consistently to the audited populations the same thresholds give different answers (FPS at or near its threshold already, Norpipe below it), so the years are suspended until minimum volumes are established for a defined population. What does not depend on them is the timing of the investment decisions: the major CCS and hydrogen projects that use this infrastructure have Final Investment Decision windows between 2025 and 2030, and infrastructure decommissioned before those decisions cannot be economically recommissioned.

6. Organisational Ecology: Population Dynamics Across Regulatory Eras

6.1 The Era Structure

Era	Period	Name	D/F ratio	Ecological mechanism
I	1964–74	Founding	0.00	Liability of newness. Continental Shelf Act 1964.
II	1975–84	Legitimacy	0.04	Institutional imprinting. BNOC. PRT introduced. Capital abundant.
III	1985–2000	Peak Founding	0.11	Density peak. Piper Alpha 1988. Privatisation.

				Crowding begins.
IV	2001–08	Fragmentation	0.35	IOC exit. PE entry. Liability of obsolescence emerging.
V	2009–15	Crisis & Imprinting	1.00	Ecological death cross: mortality equals founding. OGA founded.
VI	2016–21	Dual Mandate Transition	2.65	Mortality 2.65 times founding. Net decline structurally embedded.
VII	2022–26	Late Maturity & Fiscal Shock	3.75+	EPL era. SFS = 0.7370. Cascade thresholds crossing.
VIII	2027–30	Infrastructure Cascade	n/a	Fiscal death cross. FPS and Norpipe CoP wave (projected).
IX	2031+	Terminal Ecological Succession	n/a	Post-pipeline basin. CCS and hydrogen replace extraction (projected).

The D/F (deaths to foundings) ratios were computed on the earlier panel and are being recomputed on the current one; they are shown for orientation.

The Deaths-to-Foundings ratio is the key organisational ecology indicator. A ratio above 1.0 means more fields are closing than being created: net population decline. On the earlier panel the ecological death cross occurs in 2015, seven years before the EPL, which would mean that the EPL acted on an existing structural decline and did not initiate it.

6.2 Operator Archetype Survival

Operators are classified into five archetypes by real founding or pedigree, not by later corporate events: IOC, Large_Public_Independent, PE_Backed, Small_New_Independent and Family_Independent. Survival is compared across the five groups in the post-2010, non-CATS sample (95 cessations, 32 operators).

Archetype	Operators	Fields	CoP events	Restricted mean survival (years)
IOC	13	131	38	14.29
Large_Public_Independent	5	70	17	13.39
PE_Backed	2	131	32	13.84
Small_New_Independent	10	48	8	14.06
Family_Independent	2	54	0	not estimable (no events)

Source: 05_archetypes_ceo.log, 5 October 2026. Field-operator spells can exceed the count of unique fields because fields change operator.

A field-level log-rank test rejects equality across the five groups (chi2(4) = 16.80, p = 0.0021). That result is not robust. Fields cluster within a small number of operators, so a field-level test overstates the evidence. Permuting the archetype labels across the 32 operators, keeping each operator's fields together (5,000 shuffles), gives an operator-level p-value of 0.48. Removing Family_Independent, which comprises two operators (Perenco and INEOS) and has no cessations, collapses the test to chi2(3) = 0.43, p = 0.93. Three operators carry 52 per cent of all cessations: NEO NEXT+ (26), TAQA (12) and EnQuest (11). The restricted mean survival times differ by under a year across the four groups with events. The evidence does not support the claim that any archetype, including PE-backed operators, has a shorter lifespan. On oil-producing field-years only, with calendar time as the time scale, a log-rank test across the four archetypes with events is not significant (chi2(3) = 5.12, p = 0.16). The lifespan-scale comparison was also repeated on oil-producing field-years only (5,595 field-years, 138 closures; the Family group has a single oil field-year and is excluded) and finds no difference: chi2(3) = 1.85, p = 0.60, with an operator-level permutation p of 0.86. Restricted mean lifespan to age 25 is 20.7 years for IOCs (operator-bootstrap interval 18.4 to 22.1), 17.9 for large public independents (15.6 to 22.1), 19.4 for PE-backed operators (17.2 to 20.3) and 18.2 for

small new independents (4.0 to 22.8); none differs reliably from IOCs. The earlier p = 0.002 on all field-years does not reproduce on oil-producing field-years. Imprinting by founding cohort cannot be tested with these data. The 19 operators in the oil-producing sample span five founding eras, and each of the four later eras holds one to three operators (the 2016 and later era is NEO NEXT+ alone, with 26 of the 89 closures). Founding-era terms and the headline tax rate at founding (0.97 per 10 points, interval 0.71 to 1.35, operator bootstrap) have intervals that include 1, so the evidence neither supports nor rejects imprinting.

7. Three Scenarios to 2032

Three scenarios project the active field population forward from the 2024 base of 272 fields. They are scenarios, not forecasts. S1 (continuation of the 78 per cent EPL) applies the 2024 cessation rate of 7.46 per cent, decelerating by 1.5 per cent a year; the deceleration is an assumption, not an estimate, and a sensitivity analysis is required. S2 (EPL reform) applies the pre-EPL mean rate of 2.51 per cent (2015 to 2021, primary sample). S3 (managed transition) applies an intermediate rate of 4.0 per cent, a policy assumption.

Scenario	2025	2028	2030	2032	Change from 272
S1 Continuation	252	201	174	151	-44%
S2 EPL reform	265	246	234	222	-18%
S3 Managed transition	261	231	213	196	-28%

Source: 09_sam_recalibration.log and SAM_V15_6_0_Scenarios.xlsx, 5 October 2026 (N0 = 272; r_base 0.0746; r_reform 0.0251; r_managed 0.04; deceleration 0.015).

By 2032 the reform scenario retains 71 more active fields than continuation (222 against 151). Whether it also raises more revenue depends on the fiscal yield per field. Over 2025 to 2032 reform has 1,946 field-years against 1,576 under continuation, so reform raises more revenue only if its yield per field is at least 81 per cent of continuation's. Cutting the effective rate from 78 to 40 per cent would lower the yield per field to 51 per cent of continuation's at constant profit, so the revenue claim requires per-field taxable profit to rise by about 58 per cent under reform, through investment response or otherwise. The earlier headline of about 0.9 billion pounds more revenue, and the revenue-neutral rate of 40 to 55 per cent, rested on yields that were backed out of the stated totals, and are withdrawn. A revenue module with an explicit investment response is needed before any revenue claim is made.

8. The Fiscal Paradox

Period	OBR forecast	Actual receipts	Shortfall
2022–2024 (3-year actual)	£26.0bn (OBR, Nov 2022: 7.2 + 10.8 + 8.0)	£9.1bn	-65%

The instrument has raised far less than the November 2022 OBR forecast: £9.1bn of cash receipts against £26.0bn forecast for 2022-23 to 2024-25. Part of the gap is price error, not only a response to the levy: that forecast used the gas prices of November 2022, which later fell. Three mechanisms are visible in the 2024 company accounts.

- Effective tax rate: Harbour Energy ETR 107.6 per cent for 2024 ($1,312m tax on $1,219m profit), above 100 per cent; Serica Energy ETR 63.8 per cent (£67.6m tax on £106.0m profit before tax). The levy extracts capital, not only surplus profit.
- Tax on pre-tax loss: Waldorf Production (now in administration, and not an operator of record in the PPRS panel) paid a $33m tax charge on a $161m pre-tax accounting loss; Repsol North Sea Ltd paid $9.4m on a $55m loss.
- ARO equity stripping: Serica Energy paid £130m in dividends against a decommissioning provision of £18.8m, about 6.9 times (Serica Energy plc 2024 accounts). The Section 29/30 back-chain and the UK taxpayer bear the residual.

9. The Decommissioning Evidence Base

9.1 What was built

Alongside the field panel, Meginráð Research has built a structured extraction of public decommissioning documents filed with the Offshore Petroleum Regulator for Environment and Decommissioning (OPRED). The Body of Knowledge revised on 23 October 2026 draws on 363 documents, and every statement in it is cited to a document and page. The documents are the decommissioning programme (DP) that sets out how an installation will be removed, the environmental assessment (EA), the comparative assessment (CA) that weighs the removal options, and the close-out report that records what was done.

Document type	Documents	Share of 363
Decommissioning programme (DP)	203	56%
Environmental assessment (EA)	70	19%
Comparative assessment (CA)	55	15%
Close-out report	35	10%
Total	363	100%

Of the 363 documents, 323 are approved, 37 are consultation drafts and 3 have unknown status. Two were only partly extracted, so any count that includes them is a minimum. The three North Sea regions hold 323 of the documents, with the Southern North Sea largest at 127. Counts are of extracted documents, not of the UKCS: the corpus can hold duplicate and superseded versions, and operator names are as printed.

9.2 What the documents show

These observations are descriptive and indicative. They describe the extracted documents and are not estimates for the basin.

- Cost outturn: of 13 close-out reports that state both an estimate and an outturn, 8 ran over budget and 5 came in under. This is a sample of reports, not a rate, and cost bases differ between documents.
- Schedule: at least 10 close-out reports cite weather or vessel availability as a cause of slippage.
- Cost disclosure: costs are commonly withheld or supplied to OPRED in confidence. This is regulatory practice and is not treated as a defect, but it limits cost benchmarking from public documents.
- Internal consistency: extractor notes record contradictions inside documents, such as tables that disagree with the text, totals that do not sum, and differing dates or quantities. The notes are classified by keyword rules, so the rates are indicative and have not yet been audited. No rate is quoted here; a hand-checked sample is the next step.

9.3 A pre-submission consistency check

Meginráð Research proposes a fixed-fee, independent check that the documents in a decommissioning submission reconcile with each other and with statutory requirements before a gate. The gate model below is version 0.1. It is proposed, to be validated with practitioners.

Gate	Question at the gate	Main documents
G0 Cessation planning	Is the decommissioning scope, cost basis and timing defined?	Cessation case, scope inventory, cost estimate
G1 Option assessment	Are the options complete, screened and scored defensibly?	Comparative assessment, CA workshop record
G2 Programme submission	Do the programme and environmental assessment match the CA outcome and each other?	DP, EA, consultation record
G3 Pre-dismantling readiness	Is the revised safety case accepted and the verification scheme revised?	Safety case, risk assessment, verification scheme, well notification
G4 Phase transition	Before each substantive phase, are risks, the safety-critical element record and verification updated?	Phase risk assessment, element record, verifier comment
G5 Close-out	Are seabed clearance, monitoring commitments and lessons recorded?	Close-out report, clearance statement, survey plan

Sixteen checks apply across these gates. Examples: components, quantities and boundaries agree across the DP, CA, EA and safety case; the preferred option in the programme matches the comparative assessment outcome, and any departure from the lowest-scoring option is explained; cost basis, contingency and withheld figures are stated; rock, vessel-day and emissions figures agree between CA and EA; the dismantling safety case covers every Schedule 8 particular; and the verification scheme is revised before the safety-critical element record changes.

Gates G0, G1, G2 and G5 need confirming against current OPRED guidance. Gates G3 and G4 rest on the Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015 (SI 2015/398) and

HSE Information Sheets 2/2008 and 3/2006. The check compares documents with each other and with published requirements. It is not a regulatory approval, a safety verification or an engineering design review, and it does not replace the independent verifier or the duty holder's own assurance.

9.4 Limits of the evidence

- The extraction is a structured first pass. No accuracy rate against a hand-checked sample has yet been measured.
- Issue dates in the documents are unreliable, so no date range or trend over time is stated.
- Scores use each document's own scale and direction, and costs have no common cost year or basis, so costs are compared only inside one document.
- Findings are descriptive and exploratory and do not support causal claims.

A no-cost pilot on one approved public document set is available: sixteen checks over two weeks, a findings table and a one-page readiness summary. Enquiries: jnscott@meginrao.com.

10. Conclusions and Policy Recommendations

10.1 Principal Findings

- Fields at a water cut of 0.85 or above close at about twice the rate of other oil-producing fields (HR 1.99, 95% CI 1.25 to 3.18). Of 157 active oil producers, 51 (32 per cent) are above the threshold.
- Each year without a development well adds about 5 per cent to the closure hazard (HR 1.05, 95% CI 1.01 to 1.08). Section 29 exposure points the same way (HR 1.43) but is not statistically significant.
- The 2024 cessation rate is 4.7 percentage points above the price-predicted rate (2.7 times, 4.2 SD above the pre-EPL mean). The timing is consistent with the EPL escalations, but the design cannot establish causation, and no field-level Cox estimate of the EPL effect is identifiable.
- Hub-level closure probabilities are not reported. The audited feeder counts show where exposure sits (Forties 19 of 66 live feeders at or above a water cut of 0.85, FUKA 3 of 13, Norpipe 1 of 7, FLAGS 2 of 2), but they are counts, not probabilities, and what thin feeder populations mean physically is an engineering question.
- Under the scenarios, EPL reform retains 71 more active fields by 2032 than continuation (222 against 151). Whether that raises revenue depends on per-field taxable profit rising by about 58 per cent under reform; the earlier revenue claim is withdrawn.
- The fiscal paradox is structural: effective tax rates above 100 per cent, tax charged on accounting losses and dividend distribution exceeding decommissioning provisions are mechanical consequences of the levy's design.
- Operator archetype differences are not robust: the field-level test is carried by two Family_Independent operators and the operator-level test gives p = 0.48.

10.2 Policy Recommendations

- Restore the investment allowance: reinstate the main investment allowance (29 per cent) that was abolished for expenditure from 1 November 2024, keeping the 80 per cent decarbonisation allowance, or adopt a Norwegian-style cash-flow architecture in which most capital spending is expensed at once. In the scenario model a central case of that design raises about 15.8 billion pounds over eight years, against 16.9 billion for continuation and 10.7 billion for reform without a levy, and keeps 222 fields in 2032 against 151. It rests on stated assumptions about the share of the levy base expensed and the closure rate.
- Incorporate the UKCS field mortality rate as a leading indicator in the OBR's fiscal model.
- Publish a consolidated Section 29/30 back-chain registry. The NSTA holds the licence transfer register but does not publish a field-level view of prior interest holders and estimated liability.

- Commission a formal study of the EPL rate and its revenue consequences using this panel and the ITS estimate, including an explicit model of the investment response to a rate change, on which any revenue conclusion depends, and using classified NSTA and HMRC field-level data.

10.3 Limitations

- EPL identification: the ITS rests on seven pre-period observations, one treated unit and no control series. A field-level EPL hazard ratio is not identifiable because the lagged rate varies only across 2024 to 2026 and every cessation in that window falls in 2024.
- Clustering: standard errors are clustered by field. Fields owned by one operator are not independent, so the intervals in Table 4.1 may be too narrow; the archetype test in Section 6.2 shows how material this can be.
- The threshold result was chosen after the sample problem was found, so it needs replication before it is treated as confirmed. The water cut indicator violates proportional hazards on its own (p = 0.038), so the 1.99 is a time-averaged effect that varies strongly by period (Sections 4.3 and 4.6).
- Decommissioning programme approval is sparse (31 field-years, all in 2024 to 2026) and cannot be estimated reliably.
- Hub results: closure probabilities are not reported in this edition because the canonical cascade sub-model script is not in the repository and the figures could not be reproduced from the audited feeder data. Feeder counts are an imperfect proxy for throughput; physical minimum volumes for Norpipe and FLAGS are an engineering question for a later model phase.
- Scenario deceleration (1.5 per cent a year) and the managed-transition rate (4.0 per cent) are assumptions. Revenue effects depend on an investment response that is not modelled.
- Threshold: 0.85 is a statistical risk marker and not a limit of viability; fields commonly operate profitably to 90 to 98 per cent. The feeder counts in Section 5 are taken at 0.85 and fall at stricter thresholds.
- Gas fields: the field-level hazard excludes gas-only fields because their closures are not coded in the outcome. An exploratory gas-field model exists (Section 4.5), but it is a screening model whose production drivers are partly mechanical; gas-only hubs still have no probability.
- The archetype comparison in Section 6.2 on all field-years was significant by field but not by operator. Restricted to oil-producing field-years it is not significant on either a calendar-time (p = 0.16) or a lifespan (p = 0.60) scale. Operator-level bootstrap intervals rest on 19 operators, three of which carry 53 per cent of the closures.
- Operator archetype results rest on five groups, two of which contain two operators each, and 95 cessations concentrated in a few operators.

Companion Analyses

Working Paper No. 2 (V18) examines how the choice of standard errors affects the primary model. Working Paper No. 3 (V18) extends the analysis to operators: 36 operator groups, 868 operator-years and 8 operator mortality events. It finds a significant step down in operator portfolio closure rates when the levy was introduced (level change -0.042, p = 0.022), no detectable survival difference between operator types (log-rank chi2(4) = 5.72, p = 0.22), and withdraws an earlier stranded-holder hazard ratio of 3.7 that could not be reproduced. Working Paper No. 4 sets out the theoretical framework (nested business cycles and the cycle misalignment hypothesis) and a test design; its empirical findings are inconclusive.

Abbreviations and Key Terms

Definitions for non-specialist readers; technical readers may proceed to Section 1.

Term	Full form	Plain-English definition
ARO	Asset Retirement Obligation	The provision an operator must set aside to fund future decommissioning. Reported on the balance sheet.
CATS	Central Area Transmission System	A trunk pipeline carrying gas from central North Sea fields to the Teesside terminal. Not modelled here: it records no cessations since 2010.
CI (95%)	95 per cent confidence interval	The range that would contain the true value in 95 of 100 repeated studies. A narrow interval means a more precise estimate.
CoP	Cessation of Production	The permanent closure of a producing field, which happens when it becomes uneconomic to operate and not necessarily when its reservoir is exhausted.
Cox PH	Cox proportional hazards model	A statistical model that estimates how much each factor raises or lowers the annual chance of an event (here, field closure) while holding the others constant. Applied here to oil-producing field-years.
D/F ratio	Death-to-founding ratio	In organisational ecology, closures divided by new fields. Above 1.0 means the population is shrinking.
DP	Decommissioning Programme	The formal submission to NSTA setting out how a field will be removed. Approval is a descriptive signal of imminent closure; it cannot be estimated as a hazard ratio because approvals begin only in 2024.
EPL	Energy Profits Levy	A UK tax on oil and gas profits introduced in May 2022. With ring fence corporation tax and the supplementary charge it raised the effective rate from about 40% to 78%.
EPV	Events per variable	Closures divided by predictors. The primary model has 17.8 (89 events and 5 predictors), above the conventional minimum of 10.
ETR	Effective tax rate	Tax paid as a share of pre-tax profit. Above 100% means an operator paid more tax than it earned.
FDP	Field Development Plan	The document approved by NSTA before a field starts production. Years since consent is used as a proxy for field maturity; it shows no detectable effect on closure.
FLAGS	Far North Liquids and Associated Gas System	A West of Shetland pipeline system. On the audited feeder list it has two live gas feeders; a count only, with no probability.
FPS	Forties Pipeline System	The largest trunk pipeline in the UKCS, carrying oil from the central North Sea to Kinneil and Hound Point. A critical corridor for the Acorn carbon storage project.
FUKA	FLAGS/UKCS gas pipeline	A trunk pipeline carrying gas from northern North Sea fields to St Fergus, the planned primary Acorn injection point.
HR	Hazard ratio	The multiplier on the annual chance of closure. HR 2.0 means twice the annual chance of the comparison group; HR below 1 means a lower chance.
ITS	Interrupted time series	A method that compares what happened after a policy with what the earlier trend predicted. The gap is evidence of timing and association, not proof of cause.
Lower bound		A figure that is at least this large. Used where an assumption (here, that fields fail independently) understates the true value.
MER UK	Maximising Economic	The statutory strategy under the Infrastructure Act 2015 that requires

	Recovery UK	licence holders to maximise recovery of petroleum.
Norpipe	Norpipe oil pipeline	A trunk pipeline carrying oil from the Ekofisk area to Teesside. On the audited list it has seven live oil feeders; a count only, and it also carries Norwegian volumes.
NSTA	North Sea Transition Authority	The UK offshore oil and gas regulator, formerly the Oil and Gas Authority.
OBR	Office for Budget Responsibility	The UK's independent fiscal forecaster, whose forecasts the levy outturn is measured against.
p-value	Probability value	The chance of a result this large if there were no real effect. Below 0.05 is conventionally called statistically significant.
PPRS	Petroleum Production Reporting System	NSTA's database of monthly production for all UK offshore fields, the source of production, water cut and closure events.
Risk marker (0.85)	Water cut of 0.85	The level at which this analysis flags a field as at higher risk. It is not a limit of viability: many mature fields operate profitably well beyond it, and the economic cut-off usually lies nearer 90 to 98 per cent. The closure rate keeps rising above it.
S29	Section 29, Petroleum Act 1998	The power for NSTA to require a former interest holder to contribute to decommissioning costs, whenever they divested and whether or not the current operator is solvent.
SFS	System Fragility Score	A Meginráð Research basin score: 0.5 x fiscal friction + 0.3 x drilling decay + 0.2 x platform age stress. It is 0.7370 for 2024. Earlier editions defined it as the share of fields above a water cut of 0.85, which was incorrect.
UKCS	UK Continental Shelf	The offshore area in which the UK has sovereign rights to explore for and produce oil and gas.
WC	Water cut	The share of produced liquid that is water, from 0 (all oil) to 1 (all water). It rises as reservoirs age and is not defined for a field that produces no oil.

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