ENERGY · PAPER 05

Domestic Fuel Supply: Oil, Gas and Coal

Reopening the North Sea under ordinary corporation tax and a commercial route for domestic coal.

29 min read · October 2026

North Sea decline puts skilled workers, coastal communities and specialist suppliers at risk before replacement work is available. It also increases exposure to imported fuel while heating, industry and gas-fired power still need it. A credible domestic project pipeline can retain capability and reduce net import requirements where additional production reaches users.

We will reopen North Sea exploration and development, apply ordinary corporation tax with usable investment relief, and protect valid decommissioning rights. We will also reopen a commercial route for domestic coal mining to serve suitable industrial and electricity-generation markets. Extraction will remain privately owned, financed and operated.

Use licensing, investment and hub coordination to develop economically recoverable resources and preserve productive capability. Prioritise viable well work and tiebacks while keeping the route to new discoveries open.

The problems and the proposed remedies

PROBLEM	PROPOSED REMEDY
No dependable route to newly licensed exploration	Restore licensing for new acreage and the full exploration to production sequence.
An unstable and unusually high sector tax burden	Apply the ordinary corporation tax rate and publish a durable transition settlement.
Costs and losses arise before profitable production	Preserve qualifying deductions and usable loss rules without guaranteeing commercial success.
Hub closures can strand nearby opportunities	Resolve access and closure decisions while development options remain practical.
Employment and suppliers lose work before replacements arrive	Connect skills and industrial policy to a visible pipeline of real projects and orders.
More annual production does not ensure winter resilience	Assess deliverability, infrastructure outages, imports and storage together.

Updated 22 October 2026

Where current policy stands

Existing production and new exploration are different decisions

The November 2025 North Sea Future Plan maintains the government's commitment not to issue new licences to explore new oil and gas fields. Existing licences and development applications remain a separate category. Its proposed Transitional Energy Certificates offer a limited route for additional production near existing fields. The criteria published in April 2026 expressly exclude exploration. This is a narrower settlement than ours. [1–2]

We would retain a practical route for tiebacks and other work near existing infrastructure, while reopening new acreage to exploration. A licence provides conditional rights to undertake specified activities; it does not by itself approve drilling, a development plan or production. Restoring licensing must therefore be accompanied by a credible consent process and commercially investable terms.

The fiscal baseline is changing again

The current upstream regime has a 30% Ring Fence Corporation Tax, a 10% Supplementary Charge and a 38% Energy Profits Levy. The combined headline marginal rate is 78%, compared with a 25% mainstream corporation tax rate. The taxes have different bases and allowances: 78% is not a charge on gross sales. Petroleum Revenue Tax is set at 0% but retains a role in historical relief. [3]

The Energy Profits Levy is scheduled to end by 31 March 2030, with an earlier termination mechanism. Draft legislation published in July 2026 proposes a permanent Oil and Gas Revenue Levy, previously called the Oil and Gas Price Mechanism. It would tax sales revenue above specified price thresholds at 35%. Publication of draft legislation is not evidence that the measure is already in force. [3–4]

There are institutions and support programmes to build on

The North Sea Transition Authority already regulates licensing, production stewardship and infrastructure access. Supply Chain Action Plans and Energy Pathfinder already support visibility of work. Government has also announced a jobs service and an expanded skills passport. Our proposal should strengthen useful arrangements rather than claim to invent them. Its distinctive commitment is to maintain a route to new upstream investment and discoveries, with employment policy attached to that work. [1, 10]

Government published an interim gas security response in August 2026. It is examining commercial support for infrastructure, a possible floating regasification facility and strategic storage. These remain options under consideration. Our security framework should take account of this work and require a decision on the actual service to be purchased, its cost and who pays. [11]

Restore the complete exploration route

Licence new acreage and allow new discoveries to progress

Resume regular competitive licensing rounds for technically credible acreage, including opportunities beyond immediate tieback distance where the evidence supports a viable development. Publish a forward calendar, available geological data, selection criteria and decision dates. Licence awards should

assess technical competence, financial capacity, delivery commitments and the ability to meet closure obligations. Reasonable regulatory fees should recover administration costs transparently.

The policy must expressly cover seismic surveys, exploration wells, appraisal of discoveries and subsequent development applications. Restoring production from existing fields alone would leave the discovery pipeline closed. A discovery should have a predictable route to a development decision, subject to published requirements, rather than face a new political argument over whether exploration should have been permitted.

Prioritise quick opportunities without excluding larger prospects

Run two routes within the same licensing framework. Give early attention to well interventions, infill drilling, discovered resources and tiebacks where existing infrastructure can shorten delivery. Maintain an open route for new exploration and developments needing new facilities. Near-hub opportunities may provide earlier output; larger or more distant prospects require separate cost, infrastructure and security assessments.

The NSTA reports that interventions on existing wells added 37.5 million barrels of oil equivalent in 2024. That is evidence that maintenance and recovery work can matter to supply, not a forecast that the same increment can be repeated each year. A programme should assess specific wells and facilities before assigning output to them. [12]

Make licence commitments executable

Require staged work programmes, realistic appraisal milestones and disclosure of reasons for delay. Reallocate acreage when a licensee neither performs nor presents a credible funded alternative. Allow justified extensions for material discoveries, genuine technical difficulties or delays caused by public authorities. Avoid a rigid drilling deadline that encourages premature wells or makes an otherwise investable prospect unfinanceable.

Maintain a project-based supply register separating well interventions and infill work, tiebacks, appraised discoveries and new exploration. Record stage, expected first production, probability of proceeding, delivery range, annual and peak-day output, decline and dependencies on rigs, hubs, terminals and pipelines. Estimate incremental supply against a stated no-reform baseline. Preserve uncertainty ranges and avoid double counting connected prospects. Licence counts and gross resource estimates are not deliverable supply forecasts.

Commercial exploration risk remains with private investors. Public geological data and shared research may be funded for a defined public benefit, with a budget and disclosure rules. The baseline proposal does not reimburse unsuccessful private wells or guarantee that every discovery will become a producing field.

Give projects a coherent consent process

Use the build reforms with an offshore legal framework

Apply the principles of UK Build Reform to qualifying offshore developments, pipelines, terminals and enabling works. Establish one published project timetable, parallel examination where lawful and a named coordinator. Map petroleum consents, environmental assessment, offshore safety, marine

permissions and relevant onshore or devolved approvals before design work is locked in. An offshore development is not automatically governed by the same consent route as an English power station.

The proposed Secretary of State for Infrastructure and Delivery should resolve cross-government delivery disputes and designated infrastructure cases within the authority created by the build legislation. Energy ministers retain energy policy and programme responsibility. The NSTA should coordinate the upstream project register and delivery milestones. The Offshore Petroleum Regulator for Environment and Decommissioning (OPRED) and safety regulators retain their defined technical functions. The legislation must identify the final decision maker for each class of consent.

Additional requirements need an enforceable test

Nationally approved standards establish compliance for the questions and assumptions they expressly cover. The operator demonstrates conformity and discloses relevant site facts. Additional requirements may be imposed only if the authority establishes a material uncovered risk or unmet outcome, material new evidence undermining approval, or deficient application. It must demonstrate incremental benefit, full cost including delay, and why less burdensome alternatives are inadequate. A demand failing the statutory necessity and proportionality test cannot lawfully be imposed or maintained.

Apply the independent Infrastructure Technical Appeals Panel under UK Build Reform to designated offshore disputes, with accredited offshore specialists and binding powers to remove, vary or substitute conditions and issue scheduled technical findings. Preserve the master appeal timetable and legal challenge route. Ministers resolve strategic and integrated-consent questions within those findings; they cannot waive intolerable risk or substitute for a retained technical approval. Reuse evidence within scope and examine genuine new site effects.

A faster decision still needs a complete legal basis

The Finch judgment and subsequent offshore guidance require assessment of downstream combustion emissions. Repealing the Climate Change Act does not remove those separate assessment rules. Establish a consistent method, preserve disclosure of material effects and legislate the decision criteria under the replacement framework. National approval of extraction policy should settle its strategic rationale; site decisions examine project compliance and residual effects. Any further change to assessment law requires express amendments and consideration of remaining international obligations. [9, L7]

Apply the master service standards to qualifying designated offshore cases: thirty calendar days for validation and ordinary advice, six months after validation for repeats and twelve months for other designated projects. Transfer overdue consent decisions for determination within sixty calendar days. Only the independent panel may certify the defined clock pause or the single extension of up to thirty calendar days after transfer. Preserve shorter applicable duties. Retained safety permissions require affirmative findings; no information request restarts the clock. Resource regulators and require refusals to identify an enumerated ground and why conditions cannot remedy it.

Retain domestic jobs and industrial capability

Productive work is the foundation of skill retention

Domestic employment and capability are part of the policy's purpose. Exploration and development sustain work in drilling, subsea engineering, fabrication, offshore operations, inspection, logistics and maintenance. The case includes the ability to manage complex installations safely, supply export markets and mobilise experienced teams for other energy projects. Once firms close and skilled teams disperse, a later training initiative cannot immediately recreate that capacity.

Retaining capability needs orders as well as qualifications. Publish a rolling ten-year project and procurement outlook, separating funded commitments from likely and speculative opportunities. Link consenting and investment milestones to the expected demand for rigs, vessels, equipment and labour. Update the outlook annually and identify bottlenecks early enough for employers and colleges to respond. A forecast should not be presented as a government guarantee of private spending.

Make supplier participation practical

Build on existing Supply Chain Action Plans and Energy Pathfinder. Require major projects to provide timely information on tenders, package sizes, procurement dates and technical qualifications. Encourage packages that capable smaller suppliers can bid for, transparent selection and prompt payment. Assess actual UK activity and value added rather than treating a supplier's registered address as proof that its work is domestic. [10]

Use project supply-chain plans to disclose apprenticeships, training investment and the capabilities needed for delivery. Monitor whether successful bidders provide them. Any mandatory procurement or employment condition should be legally assessed, proportionate and reflected in project economics before licence commitments are made. Avoid promising a fixed domestic share that cannot be supplied at the required quality or on the project timetable.

Support mobility without making departure the objective

Keep portable qualifications and skills passports where they reduce unnecessary retraining. Offer pathways between upstream operations, decommissioning, offshore networks and other energy construction. Work with employers, unions, colleges and the devolved administrations on recognised competence and training capacity. Experienced workers should be able to remain in productive upstream roles while those roles exist, or move to other work when it is available.

Target training support at demonstrated shortages and employer commitments. Publish its cost and results. Measure retained and newly created direct employment separately, distinguish permanent roles from construction job-years, and avoid counting the same worker in several energy programmes. Regional effects matter: a national total can conceal the loss of a specialist cluster or the absence of replacement jobs within realistic travelling distance.

The policy cannot preserve every company or job irrespective of productivity and demand. Its test is whether investable projects, better coordination and targeted training sustain economically useful capability. That is a stronger domestic employment settlement than allowing viable activity to contract while relying on future retraining to absorb the consequences.

Rebuild a commercial domestic coal industry

Reopen a lawful, investable route for privately financed domestic coal production. Support viable projects serving steelmaking and other industrial users, alongside suitable power-station fuel markets. The purpose is to retain employment, mining skills and supplier capability, and reduce net fuel import requirements where domestic output can competitively replace imports.

Coordinate domestic coal development with the first station and subsequent conditional tranches in Generation Expansion and Mutual Finance. Regular generation can broaden the industry's market during the nuclear build-out, while other stations support balancing and later reserve. Assess deposits, saleable grades, transport and credible purchase commitments together; industrial and power-station customers need not use identical coal or the same mine.

Require a commercial production plan, funded restoration, permissions and a schedule aligned with customer demand. Model coal output and stocks under changing regular, balancing and reserve roles as nuclear expands. Disclose minimum-volume liabilities and import fallback; no indefinite protected market is assumed. A reserve station still needs maintained equipment, usable stocks and a replenishment route.

Map the coal-specific licensing, planning and operating changes required to reopen development in each jurisdiction and bring forward the necessary legislation and consent arrangements. Apply UK Build Reform within its territorial scope and agree any devolved route. Keep mine finance and restoration obligations separate from the generation mutual; no oil-and-gas tax relief or decommissioning right is extended to coal by implication.

Apply standard corporation tax

One ordinary headline rate for future profits

From the reform's effective date, apply the ordinary corporation tax schedule to upstream profits, with the mainstream rate for large producers. Today that rate is 25%; the commitment is to the ordinary rate applicable when the reform takes effect, not a permanent sector exemption from future general changes. End the Supplementary Charge and any remaining Energy Profits Levy prospectively. Do not introduce the proposed Oil and Gas Revenue Levy; remove it prospectively if it has entered law by then.

This is a material choice to reduce the sector's additional tax burden. It applies to future accounting periods for both existing and new projects. Restricting relief to newly licensed fields would leave investment in existing hubs under a different settlement and complicate shared infrastructure. Conversely, a broad reform benefits production that would have continued anyway. Its fiscal assessment must identify that benefit rather than attribute every pound of relief to additional output.

Keep the accounting protections that remain useful

Retain an upstream accounting ring fence to distinguish UK extraction activity, control unrelated loss offsets and prevent excessive related-party financing deductions. Adapt the rules to the ordinary tax rate. A ring fence need not imply a higher sector rate. Permit genuine financing costs under clear rules, including the normal protections against artificial profit shifting and excessive interest.

Publish legislation, commencement rules and worked examples before investment decisions depend on them. Set out treatment of companies with multiple fields, joint ventures, financing arrangements and projects spanning the reform date. Preserve valid liabilities for earlier periods: prospective reform is not a refund of previously lawful windfall taxes.

Make the settlement durable without promising an impossible guarantee

Commit to a ten-year policy framework, advance consultation and notice for material discretionary changes. Future Parliaments retain taxing powers. Preserve existing relief deeds and other enforceable rights; specify any new contractual termination or allocated change-in-law protection. General tax and regulatory changes remain investor risks unless a priced, bounded clause expressly allocates them. No blanket indemnity follows. Stability rests on a credible settlement, consistent administration and productive domestic investment.

Our proposal accepts lower public capture of high-price upside through sector-specific levies. Ordinary profit tax still increases in cash terms when taxable profits rise, but it does not reproduce the revenue levy. The justification is improved investment conditions and domestic capability, not a claim that additional taxation has no fiscal value. Changes in oil prices, gas prices and production should all be reflected in the public cost assessment.

Removing additional levies is only part of the investment settlement. Deductions, loss timing and closure relief determine the cashflow an investor can actually finance. Those provisions must be settled at the same time as the headline rate.

Make real investment costs deductible

Preserve usable relief rather than announcing it twice

Most capital expenditure on exploration and appraisal already qualifies for a 100% deduction through capital allowances; qualifying upstream plant and machinery also has a first-year allowance route. These are not a new invention in our proposal. The reform must preserve their practical operation when the sector moves to the ordinary headline tax rate, including rewriting any eligibility provisions tied to the Supplementary Charge. [5–6]

Allow the immediate deduction of qualifying, genuinely incurred exploration, appraisal and development costs. Publish rules for unsuccessful wells, seismic work, shared infrastructure, asset purchases and rehabilitation spending. Keep safeguards against inflated connected-party charges and duplicate deductions. Relief should recognise an actual investment cost; it should not depend on whether a well happens to make a commercial discovery.

A deduction is not an upfront cash grant

At a 25% tax rate, a qualifying £100 million cost can reduce tax by £25 million when it is fully usable against taxable profits. It does not automatically provide £25 million of cash to an explorer with no taxable income. The immediate funding requirement, the possibility of failure and the delay before using a loss remain private risks. This illustration assumes the entire cost qualifies and sufficient taxable profits exist; it is not a forecast project return.

Provide a clear route to carry qualifying losses forward against future UK upstream profits and to use genuine upstream group relief where conditions are met. Retain appropriate carryback provisions for closure and terminal losses. Publish the restrictions and ordering rules so a lender or investor can model the expected relief. Do not allow unrestricted sale of losses or offset against unrelated income simply to manufacture a refund.

Account for the delay before production

Retain the Ring Fence Expenditure Supplement initially, including its current 10% annual uplift for up to ten accounting periods, for qualifying new expenditure as well as valid pre-reform amounts. Rewrite eligibility where necessary for the ordinary-rate upstream ring fence. Do not replace it with CPI adjustment without company and project cashflow modelling: explorers without taxable profits can wait much longer for relief than established producers. Any later replacement must demonstrate investability, protect committed expenditure and accrued entitlements, and provide prospective transition rules. Neither the supplement nor a deduction guarantees a cash refund for unsuccessful exploration. [7]

Record already accrued supplements and valid pre-reform losses separately. Preserve their eligibility, ordering and legally protected treatment through explicit transition schedules. An accounting loss is not necessarily an enforceable right to a cash refund at a historical tax rate. The schedules must distinguish ordinary unused losses from rights under decommissioning arrangements and identify where conversion would otherwise diminish a valid entitlement.

A company that never earns relevant profits may still be unable to use an exploration loss. We should state that plainly. The proposal improves tax recognition and timing; it does not make geological failure a taxpayer-funded event.

Protect the decommissioning settlement

Keep private responsibility and honour valid existing rights

Each project should carry a credible plan and financial provision for plugging wells, removing facilities and meeting environmental obligations. Tax relief reduces the net cost of eligible expenditure; it does not remove the operator’s responsibility to complete the work. A lower tax rate must not be used to justify weaker security or a transfer of unfunded liabilities to the public.

Existing Decommissioning Relief Deeds provide contractual protection for specified relief. HMRC’s current guidance also makes clear that they do not confer Energy Profits Levy decommissioning relief. A transition must therefore examine actual rights, rather than assume that a producer paying a combined headline rate of 78% receives closure relief at that rate. [8]

Separate historical rights from the future tax settlement

Publish field and company transition schedules for tax histories, qualifying liabilities, accumulated losses, relief deeds and Petroleum Revenue Tax adjustments. Honour legally enforceable historical rights. Apply the new ordinary-rate rules to future activity and relief outside protected arrangements, with an explicit method for allocating shared or continuing liabilities. Avoid a blanket rule that all expenditure after commencement receives only the new rate regardless of an existing deed.

Do not promise a general compensation payment for every reduction in expected tax relief. Identify contractual rights and statutory relief separately, then disclose any additional transition concession as a policy cost. Preserve necessary historical accounting mechanisms until the liabilities they administer are settled; abolishing a tax name should not erase a valid repayment route or create a duplicate refund.

Allow responsible transfers and continued investment

Existing transferable tax history rules can, subject to conditions, help a purchaser obtain relief for qualifying decommissioning losses against transferred historical profits. Build on that mechanism rather than creating a speculative new market in tax credits. Adapt it to the new regime with HMRC approval, auditable records and controls against double use. [13]

Before consenting to an asset transfer, assess the buyer's operational competence, financial capacity, security and remaining liabilities. Require reliable funding arrangements and a clear account of the obligations that remain with other parties. Tax history alone is not money available to clean up an installation; guarantees and financial security need an assessment of whether they will remain effective in distress.

The objective is a workable market in assets that can still be operated responsibly, followed by funded closure. It is not to postpone decommissioning indefinitely or permit an operator to extract remaining revenue and abandon the obligation. Publish the expected public cash cost of historical relief alongside private gross liabilities, so the reform's fiscal effects remain visible.

Keep shared infrastructure useful

A hub can close before nearby prospects are ready

Platforms, processing facilities, pipelines and terminals determine whether surrounding resources can reach market. A small discovery may depend on a facility whose existing production is declining. Closure can remove the economic route for several prospects at once. A project register should therefore show the expected operating window, condition and available capacity of shared infrastructure, alongside nearby appraisal and development milestones.

Require early notice of proposed closure and a coordinated assessment of credible third-party projects before irreversible expenditure or shutdown. Set a limited decision period for prospective users to present funded commitments. An unfunded possibility of future discovery should not oblige an owner to maintain a costly installation indefinitely.

Resolve access with fair payment and firm decisions

The NSTA already has a statutory third-party access framework and guidance. Our change is to make the process more timely and align it with development and closure decisions. Publish standard information requirements, a negotiation period and a decision timetable once a complete dispute is accepted. Preserve recovery of relevant operating costs, maintenance, risk and a reasonable return; access is not a right to free use of someone else's investment. [14]

Where several projects need a hub, negotiate shared costs and commitments before the original field's decline makes the operator insolvent or forces closure. Assess necessary modifications, gas quality, available capacity and reliability. Resolve whether an economically sound transfer, operating consortium

or new service agreement can preserve the facility. Owners and new users should bear the commercial costs their projects justify.

Purchase a public security service only where it is needed

If a facility has demonstrable system value that private users cannot fund, assess a bounded public contract against closure, replacement, imports, storage and demand response. Define the service, term, availability conditions, payment ceiling, maintenance obligations and exit arrangements. Compete the service where practical and disclose subsidy and contingent liabilities. Call public support what it is, rather than describing it as costless coordination.

Protect essential pipelines and terminals through licensing, transaction scrutiny and proportionate security conditions. Restrictions should address loss of control over a critical service, access or operational capability. Ordinary extraction companies may have overseas investors and lenders. We are not extending the generation mutual's ownership restriction to every offshore asset or insisting that every pound of upstream finance be British.

Complete this infrastructure assessment alongside appraisal. Waiting for a field to secure final approval before addressing a hub's survival can leave a formally approved project with no viable route to market.

Improve supply security and assess price effects

Measure the fuel that can actually reach users

Measure additional usable domestic supply against net import requirements, with demand, exports, infrastructure and market conditions explicit. Publish annual volumes and winter peak-day deliverability, including maintenance and loss of the largest relevant asset. Domestic output can reduce import dependence without guaranteeing self-sufficiency or cheap gas.

Require a joint gas and electricity stress assessment using Electricity Supply through the Transition. In 2040, Holistic Transition with 12 GW nuclear requires about 431 TWh of gas fuel for power alone at 58% efficiency; Electric Engagement with the same ramp requires about 522 TWh, and the additional-demand-plus-delay case about 535 TWh. These precede gas for heating and industry. Test cold, low wind, nuclear outages, LNG or pipeline disruption, interconnector scarcity and storage depletion; identify daily deliverability, network deficits and funded remedies. [11, 16]

Carry selective gas retention and constrained replacement delivery into the joint assessment. A retained station can reduce near-term equipment demand but still needs fuel and refurbishment, and its eventual retirement remains in the model. Procure generation availability, equipment slots and gas access together; test heating and industry competition, LNG and pipeline disruption and peak-day deliverability. Additional North Sea output is relief against the gap, not a guarantee of power-sector self-sufficiency.

Domestic gas can affect a regional market

Gas reaches Britain through infrastructure with physical capacity, transport costs and alternative buyers. Extra UK supply can change the need for marginal imports and, under some conditions, the regional wholesale price or scarcity premium. The effect depends on the volume, timing, connected markets and constraints. The appropriate claim is that price effects should be modelled, not that British production can never matter or that reopening exploration guarantees cheap gas.

Publish separate normal-market, scarcity-price and physical-shortage cases. Identify displaced imports, connected-market responses and infrastructure constraints; quantify expected interruption and the value of avoiding it with uncertainty ranges. Cross-check results against the project-based supply register. Producers sell commercially under their contracts and applicable law. The electricity purchaser has no right to acquire privately produced fuel at production cost.

Oil needs a different security assessment

Oil production, refinery feedstock and the supply of petrol, diesel and other products are different parts of the chain. More domestic crude does not automatically mean more usable road fuel if grades, refinery capacity or logistics do not match demand. Assess crude exports, product imports, processing capacity and storage together. Estimate trade effects net of imported equipment and services. Report overseas profit flows separately when assessing the wider current-account benefit. The gross sales value of extra output is not an equal improvement in the national balance of payments.

Keep enough refining and fuel stocks for security

In 2025 the UK imported about 44 million tonnes of primary oils and exported about 27 million. Net imports of petroleum products reached about 15.5 million tonnes, the highest since the UK became a net product importer in 2013; diesel was almost 40% of product imports and jet fuel about a third. Only about a tenth of the crude used by UK refineries came from UK fields, because most North Sea crude is sold abroad at world prices. Grangemouth stopped refining and Lindsey closed in 2025, leaving four large refineries with just over one million barrels a day. [17, 18]

Set the security requirement first: the volumes of diesel, jet fuel and other products the country must be able to supply through a defined interruption, by region. Then compare the ways of meeting it on cost and resilience: larger product stocks; import terminals and storage with diverse supply routes; and availability contracts that keep a minimum domestic refining capacity. Stocks are usually cheapest against short interruptions. Refining capacity protects against longer disruption to product markets but costs more, because margins are thin. Pay for the service the assessment shows is needed, not to keep every plant open.

The UK meets its emergency stock obligations by placing requirements on fuel suppliers rather than through a central stockholding agency. Assess whether an agency holding product stocks, as several European countries use, would be cheaper or more secure. Domestic crude supplies domestic refineries only where grades, configuration and prices match, so do not promise that more North Sea output keeps refineries open. The lower charge under Appendix C’s carbon tax improves refinery margins at the margin; test whether it changes closure decisions before paying for capacity. Removing vehicle sales quotas slows the fall in road-fuel demand, which raises the value of product security (Transport and Heat Demand). [19]

Keep emergency capability distinct from ordinary purchases

Develop reserve and resilience contracts only after a system assessment demonstrates need. Specify usable stock, withdrawal rate, replenishment, control of release and access during distress. Publish the proposed payer and prevent duplicate payment for an existing obligation. A public contract may buy an emergency service from a private operator; it need not bring extraction into the generation mutual or guarantee normal producer revenues.

Set credible standards and a fiscal test

Permit investment under clear operating requirements

Maintain well integrity, worker safety, spill prevention, methane measurement and enforceable conditions on routine venting and flaring. Publish requirements early so operators can design and price compliance. Apply the build paper's necessity and proportionality test to additional project conditions, with independent technical evidence and an effective challenge route.

Assess proposed electrification and other emissions improvements by the reduction achieved, remaining asset life, infrastructure requirements and total cost. A measure that is practical for a long-lived hub may be disproportionate for a facility nearing closure. Conversely, the difficulty of a project should not excuse avoidable leaks or an unsafe installation. Separate minimum operating obligations from optional improvements seeking public funding.

Apply UK Energy Reform Programme Annex Appendix C's replacement objectives and carbon settlement. Measure production and downstream emissions, disclose import-displacement assumptions, and preserve well integrity, pollution prevention and funded closure.

Do not assume the reform pays for itself

Publish an independently challenged comparison of ordinary-rate taxation with the inherited regime and a stable higher-rate alternative. Separate relief for existing production from induced investment and output; include losses, historical decommissioning, administration, training and security contracts. Record cashflows and opportunity costs in UK Energy Reform Programme Annex Appendix E before fiscal commencement.

Use low, central and high prices, company-specific financing constraints, project failure and alternative investment responses. Report annual cash effects and discounted value beyond the first term, including cases where receipts fall without much extra production. Industry forecasts supporting a stable replacement levy do not establish that a 25% ordinary rate is necessary. Separate modelled security and employment benefits from Exchequer receipts; publish assumptions so competing tax settlements can be compared on the same project portfolio. [15]

Publish results that can change the programme

Report additional investment decisions, wells drilled, appraised discoveries, first production, incremental output against a stated baseline, hub life, private liabilities and public exposure. Track employment, apprenticeships and domestic value added separately. A licence count or industry spending forecast is not proof of policy success. Commission a review after three years, preserving existing valid commitments while adjusting ineffective procedures and future interventions.

Standard corporation tax is a deliberate investment policy with an opportunity cost. Its credibility depends on admitting that cost, making relief usable and obtaining evidence of actual additional activity. It should be judged alongside the broader build programme's competing demands on public money and delivery capacity.

Prepare on taking office and commence the fiscal settlement in year one

The first term should deliver a functioning investment route, improved existing production where viable and a credible pipeline beyond year five. It should not promise that every newly licensed exploration prospect will produce within five years. Delivery speed depends on what is already known, infrastructure, approvals, procurement and the private decision to invest.

PERIOD	PRIORITY	EVIDENCE OF DELIVERY
First six months in office	Introduce fiscal legislation and transition schedules under Programme Annex Appendix F; target new tax rules from the start of year one. Prepare or reopen licensing where existing powers allow; remove any inherited statutory prohibition before awards. Map consents and hub risks.	Clear commencement rules, responsible authorities, a licensing calendar and a verified project register.
To the end of year one	Advance well work, discovered resources and viable tiebacks; settle infrastructure access; launch new exploration commitments.	Funded work programmes, consent decisions, rig or supplier commitments and resolved hub agreements.
Years one to three	Deliver projects ready for construction; appraise discoveries; expand training against confirmed demand.	Investment decisions, completed work, attributable output and documented employment and apprenticeship outcomes.
Years three to five	Review fiscal and supply effects; progress longer developments; update the next ten-year outlook.	Independent performance assessment, funded follow-on projects and a revised security and procurement plan.

Use existing bodies with explicit accountability

Treasury and HMRC should deliver tax legislation and transition rules. Energy ministers should replace the North Sea Transition Authority mandate and strategy, including its current net-zero obligation, and own the joint supply-security assessment. The authority maintains licensing, the project register, stewardship and infrastructure access. The Infrastructure and Delivery Secretary resolves designated delivery disputes. The system operators and relevant administrations supply fuel, infrastructure and demand evidence.

Keep the boundary with the other essays clear

Oil and gas extraction remains private. The generation mutual may own new gas power stations and contract for fuel, but does not acquire a preferential claim over North Sea production. The electricity central purchaser buys defined generation services under the market essay; it does not become the compulsory buyer of all oil and gas. Network sovereignty protections apply to strategic infrastructure through the relevant sector arrangements, without a blanket ban on overseas capital. Existing infrastructure access, closure and security proposals remain in force; no additional structural ownership reform is introduced. New public support uses the market paper's procurement and subsidy-control schedule.

Honour valid renewable commitments; domestic extraction does not make their supply immediately dispensable. Fracking Research and Private Development supplies the separate onshore route, engineering mission and bounded support. Use the shared assumptions and funding register in UK

Energy Reform Programme Annex Appendix E for consistent supply, cost and public-exposure appraisal.

Legislative settlement for domestic extraction

Replace the governing mandate

Repeal the Climate Change Act 2008 and its national target and carbon-budget duties. Locate the replacement objective and strategy in Petroleum Act 1998 Part 1A, and amend connected licensing, consent and regulator powers, including the Energy Act 2016 where required. The mandate promotes economically viable recovery, supply resilience, domestic capability and responsible closure. Preserve safety, pollution prevention and funded decommissioning. Additional electrification and emissions requirements face the enforceable necessity and proportionality test. [Programme Annex sources L1, N4]

Make compliant development the statutory presumption

Licensing and development legislation should require approval of a compliant, adequately assessed application unless an enumerated refusal ground is established. Grounds should cover financial or technical incapacity, failure to meet retained safety or environmental duties, unresolved material residual impacts, or incompatibility with a binding designation or essential infrastructure condition. Refusal must identify the ground, evidence and why proportionate conditions cannot resolve it. Publish the decision timetable, escalation route and appeal. This does not automatically license an unsafe well or erase site-specific evidence requirements.

Keep the carbon settlement explicit

Apply Programme Annex Appendix C's carbon tax settlement, replacing the UK ETS with a £10 per tonne CO2e carbon tax and abolishing UK CBAM, targeting the transition at the start of year two. Include applicable pre-closure installation costs, the £10 carbon tax case and overseas exposure in project appraisal. Keep ordinary fuel duties separate; distinguish operating carbon-cost relief from the upstream corporation-tax reform.

The wider energy package separately amends the 2013 emissions performance standard for generation and the 2023 institutional duties. Petroleum consent and Finch assessment rules require their own legal mapping. Review international and devolved obligations expressly; domestic repeal does not withdraw Britain from treaties or repeal separate devolved Acts. Preserve climate-risk reporting and adaptation duties through replacement provisions. [Programme Annex sources L2, L5–L8]

What this paper does not claim

Licensing and tax reform do not guarantee recoverable reserves, additional output, fiscal gains or lower market prices. Domestic production must reach users; private operators retain commercial and closure risks.

Sources and scope

Policy baseline checked on 11 October 2026. Dates below identify the source or relevant update, rather than an assumption that every announced measure has become operational. Numbered references support factual statements; the proposed reforms, implementation dates and evaluative tests are our recommendations. No production, employment or fiscal gain is presented as a guaranteed forecast.

[1] Department for Energy Security and Net Zero North Sea Future Plan 26 November 2025

https://www.gov.uk/government/news/north-sea-future-plan-for-fair-managed-and-prosperous-transition

[2] Department for Energy Security and Net Zero Criteria for Transitional Energy Certificates 21 April 2026

https://www.gov.uk/government/publications/transitional-energy-certificates/criteria-for-transitional-energy-certificates

[3] North Sea Transition Authority Taxation current regime and historical relief

https://www.nstauthority.co.uk/regulatory-information/exploration-and-production/taxation/

[4] HM Treasury Written ministerial statement on draft legislation including the Oil and Gas Revenue Levy 13 July 2026

https://questions-statements.parliament.uk/written-statements/detail/2026-07-13/hlws225

[5] HMRC Oil Taxation Manual OT26001 Exploration and appraisal expenditure updated 30 July 2026

https://www.gov.uk/hmrc-internal-manuals/oil-taxation-manual/ot26001

[6] HMRC Capital Allowances Manual CA23157 North Sea ring fence plant and machinery

https://www.gov.uk/hmrc-internal-manuals/capital-allowances-manual/ca23157

[7] HMRC Oil Taxation Manual OT26106 Ring Fence Expenditure Supplement introduction

https://www.gov.uk/hmrc-internal-manuals/oil-taxation-manual/ot26106

Sources and companion papers

[8] HMRC Energy Profits Levy and Decommissioning Relief Deeds current guidance

https://www.gov.uk/government/publications/oil-and-gas-taxation-decommissioning-relief-deeds/energy-profits-levy-decommissioning-relief-deeds

[9] Department for Energy Security and Net Zero New guidance issued for environmental impact assessments 19 June 2025

https://www.gov.uk/government/news/new-guidance-issued-for-environmental-impact-assessments

[10] North Sea Transition Authority Supporting the supply chain

https://www.nstauthority.co.uk/what-we-do/supporting-the-supply-chain/

[11] Department for Energy Security and Net Zero Gas system in transition security of supply interim response published 18 August 2026

https://www.gov.uk/government/consultations/gas-system-in-transition-security-of-supply

[12] North Sea Transition Authority Wells intervention results and production stewardship

https://www.nstauthority.co.uk/regulatory-information/exploration-and-production/wells/

[13] HMRC Oil Taxation Manual OT63010 Transferable tax history and the buyer

https://www.gov.uk/hmrc-internal-manuals/oil-taxation-manual/ot63010

[14] North Sea Transition Authority Guidance on Third Party Access to Upstream Oil and Gas Infrastructure November 2022

https://www.nstauthority.co.uk/media/8509/final-updated-tpa-guidance-7-nov-22.pdf

[15] Offshore Energies UK. New government can revitalise North Sea energy industry with policy reset. 20 July 2026. Industry forecasts for a stable replacement regime are not evidence that ordinary-rate taxation alone is required.

https://oeuk.org.uk/new-government-can-revitalise-north-sea-energy-industry-with-policy-reset/

[16] Kathryn Porter. Gas security the foundation of energy security. 27 September 2026. Integrated gas and electricity planning and regional price effects.

https://watt-logic.com/2026/09/27/gas-security-the-foundation-of-energy-security/

[17] Department for Energy Security and Net Zero. Digest of UK Energy Statistics 2026, Chapter 3: oil and oil products. 2025 crude and product trade, refinery output and supply sources.

https://assets.publishing.service.gov.uk/media/6a69f02d16bc92f51e1a4337/DUKES_2026_Chapter_3.pdf

[18] Natalia Katona, OilPrice.com. Britain’s golden refining era ends. 11 September 2025. Remaining refineries, capacities and the diesel supply gap.

https://oilprice.com/Energy/Energy-General/Britains-Golden-Refining-Era-Ends.html

[19] International Energy Agency. United Kingdom’s legislation on oil security. Stockholding obligations placed on suppliers; no central stockholding entity.

https://www.iea.org/articles/united-kingdoms-legislation-on-oil-security

Companion papers

UK Electricity Market Reform, Legacy Renewable Commitments, Generation Expansion and Mutual Finance and UK Build Reform provide the market, contract, ownership and delivery framework. UK Energy Reform Programme Annex holds the shared rules and funding register; Electricity Supply through the Transition provides the quantitative supply and fuel-security scenarios. Fracking Research and Private Development specifies the onshore route, engineering programme and bounded support; Other Energy Sources and Storage covers wider resource appraisal. Transport and Heat Demand sets vehicle and heating demand policy and its effect on fuel imports.

Shared legislative sources appear in UK Energy Reform Programme Annex.

[N4] UK Parliament. Petroleum Act 1998 Part 1A. Principal objective and strategy framework. Apply the text and connected regulator powers inherited at commencement.

https://www.legislation.gov.uk/ukpga/1998/17/part/1A