

The North Sea Gas Paradox

System Architecture Constraints in Offshore Gas Flow

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Abstract

Across the North Sea, a structural contradiction has emerged: natural gas is present, technically recoverable, and located in close proximity to existing infrastructure — yet increasing volumes fail to reach the market.

This paper argues that the limiting factor is no longer resource availability or geographical connectivity, but the architecture and operational constraints of the existing offshore gas system. By analyzing two distinct system types — the Norwegian Continental Shelf (NCS) and the Southern North Sea (UK–Netherlands) — the study identifies a set of recurring failure mechanisms that prevent technically viable gas from being produced and monetized.

The findings suggest that the current system is no longer able to reliably convert available gas into flow, indicating a structural transition in offshore gas production dynamics.

1. Introduction

The North Sea has long been one of the most developed offshore gas provinces in the world. Over decades, extensive infrastructure has been built to connect offshore fields with onshore processing and distribution systems.

Historically, the dominant assumption has been that proximity to infrastructure ensures economic viability. Fields located near pipelines or processing hubs were considered inherently advantaged due to lower development costs and simplified integration.

However, this assumption is increasingly no longer valid.

Recent developments across both the Norwegian Continental Shelf and the Southern North Sea indicate that gas can remain unproduced or delayed despite being located within operational distance of existing infrastructure. This suggests that the limiting factors have shifted from physical connectivity to system-level constraints.

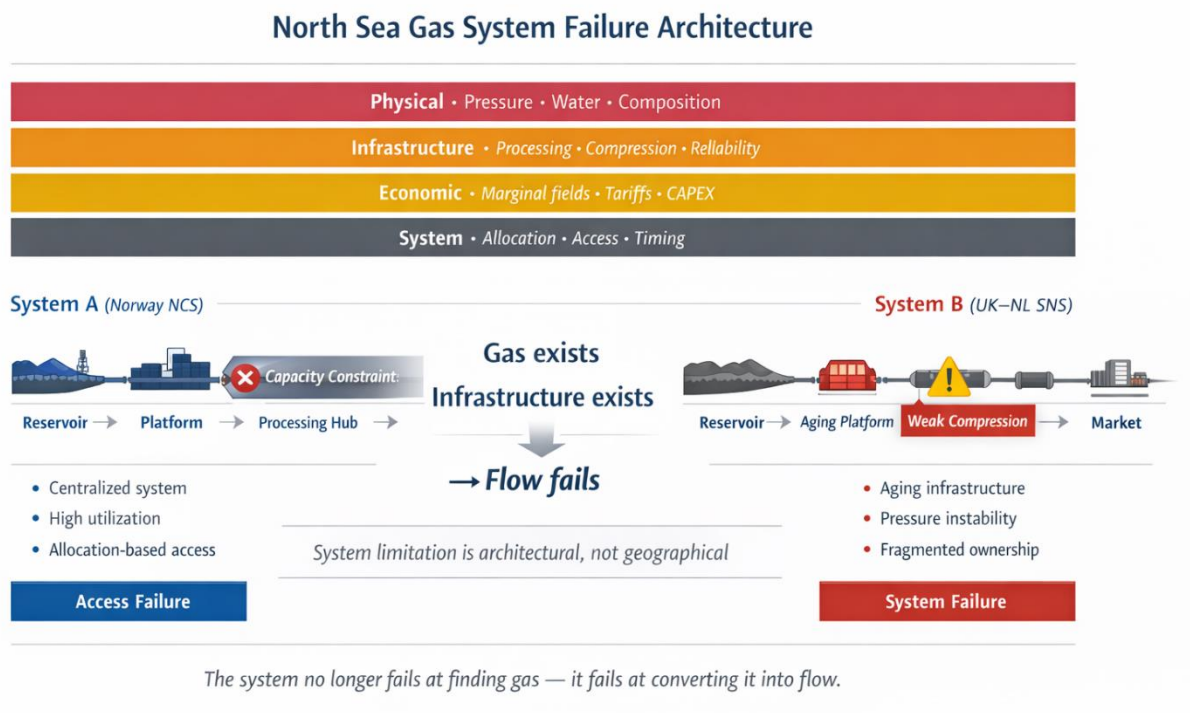
2. Methodological Approach

This study adopts a system-level analytical framework, combining four interdependent dimensions:

- Physical conditions (pressure, composition, flow assurance)
- Infrastructure constraints (processing capacity, compression, reliability)
- Economic factors (CAPEX, OPEX, tariffs, field size)
- System and organizational structures (capacity allocation, joint ventures, access regimes)

Rather than evaluating individual fields in isolation, the analysis focuses on identifying recurring patterns across the system, with particular attention to conditions under which gas fails to transition from resource to market flow.

3. Two Distinct System Types in the North Sea



3.1 Norwegian Continental Shelf (NCS): Capacity-Constrained System

The Norwegian system is characterized by:

- centralized infrastructure
- high utilization rates
- coordinated production and export systems

Despite its efficiency, the system exhibits a critical constraint: limited access to processing and export capacity.

Production from satellite fields is frequently governed by predefined capacity allocations. Even when gas is technically available, it may not be produced if access to processing, compression, or export capacity is restricted.

This results in a condition where gas is not physically blocked, but systemically constrained by allocation and capacity limits.

3.2 Southern North Sea (UK–Netherlands): Aging Infrastructure System

In contrast, the Southern North Sea represents a late-stage system characterized by:

- aging infrastructure
- fragmented ownership structures

- declining reservoir pressures
- increasing operational costs

Here, the dominant constraint is not access, but system degradation.

Common issues include:

- insufficient compression
- pressure mismatches
- gas quality constraints (e.g., dew point, water content)
- reliability issues in aging facilities

As a result, infrastructure may still exist geographically, but is no longer capable of supporting stable or economically viable production.

4. Systemic Failure Mechanisms

Across both systems, four categories of failure mechanisms can be identified:

4.1 Physical Constraints

- declining reservoir pressure
- increased water production
- gas composition challenges
- flow assurance risks

These factors directly affect the ability of gas to enter and move through the system.

4.2 Infrastructure Constraints

- limited processing capacity
- lack of compression at critical nodes
- single points of failure
- reduced system reliability in late-life assets

In the NCS, these manifest as capacity saturation.

In the Southern North Sea, as infrastructure decay.

4.3 Economic Constraints

- marginal field sizes (often 5–30 mmboe)
- rising operating costs
- high tariffs for third-party infrastructure access
- unfavorable CAPEX-to-revenue ratios

These factors determine whether technically feasible production is economically viable.

4.4 System and Organizational Constraints

- reserved capacity allocation
- dependence on host infrastructure
- joint venture alignment issues
- timing constraints related to shutdowns and integration windows

These constraints often prevent production even when physical and economic conditions are favorable.

5. System Dynamics and Lifecycle Effects

Offshore gas systems are not static; they evolve over time.

Three generalized phases can be identified:

- Expansion phase: infrastructure build-out and rapid growth
- Optimization phase: high utilization and efficiency improvements
- Decline phase: pressure loss, aging assets, rising costs

The Norwegian Continental Shelf largely operates in an optimization phase, where capacity limits dominate.

The Southern North Sea is predominantly in a decline phase, where infrastructure degradation and economic constraints define system behavior.

This lifecycle perspective explains why similar physical conditions can lead to fundamentally different constraints across regions.

6. Economic Consequences

The identified system failures have direct economic implications:

- delayed production from viable fields
- stranded or underutilized gas volumes
- reduced throughput in existing infrastructure
- diminished project viability for marginal developments

Importantly, these effects occur despite the continued presence of recoverable resources.

This indicates a growing mismatch between resource availability and system capability.

7. Central Finding

The core finding of this study can be summarized as follows:

The North Sea gas system no longer fails at finding gas — it fails at converting it into flow.

This represents a structural shift in the limiting factors of offshore gas production.

Detailed supporting analyses for both system types and their combined failure patterns are provided in **Appendix A–C**

8. From System Failure to System Requirements

The identified failure mechanisms do not point to isolated technical deficiencies, but to structural limitations of the existing system architecture.

As a result, any viable future system must meet a fundamentally different set of requirements:

- independence from centralized processing constraints
- tolerance to variable and declining pressure regimes
- scalability for small, fragmented, and short-cycle volumes
- reduced dependency on rigid capacity allocation systems
- ability to operate under late-life infrastructure conditions
- resilience against single points of failure

These requirements emerge directly from the failure patterns observed across both system types.

Importantly, they cannot be fully addressed within the constraints of the current hub-based architecture.

Various technological and architectural approaches may attempt to meet these requirements. Their evaluation, however, lies beyond the scope of this study.

9. Potential System-Level Benefits of Overcoming Structural Constraints

The failure mechanisms identified in this study are not only limiting factors, but also indicators of unrealized system potential.

If the structural constraints of the current architecture were partially or fully overcome, several system-level effects would emerge:

- **Increased recovery of marginal fields**
Smaller accumulations currently considered uneconomic could become viable under more flexible offtake conditions.
- **Reduction of stranded gas volumes**
Technically recoverable resources would be more consistently converted into production, reducing the gap between reserves and flow.

- **Improved system throughput stability**
The dependency on a limited number of centralized processing hubs would decrease, reducing sensitivity to capacity bottlenecks and single-point failures.
- **Extended economic life of existing assets**
Infrastructure currently approaching decommissioning thresholds could remain operational under less constrained conditions.
- **Shorter time-to-production for satellite fields**
Reduced reliance on complex allocation, integration, and modification processes would enable faster monetization.
- **Higher resilience under variable operating conditions**
Systems capable of handling fluctuating pressure regimes and fragmented volumes would better reflect the realities of late-stage offshore production.

These potential benefits do not arise from a single technological solution, but from a structural shift in how offshore gas systems handle access, flow, and integration.

In this sense, the current system does not only limit production — it actively suppresses economically viable output.

This is not a theoretical projection, but a direct consequence of removing the constraints identified in the current system.

10. Conclusion

The challenges currently observed in the North Sea are not isolated technical issues, but manifestations of a broader systemic transition.

Gas remains available. Infrastructure remains present.
Yet the system increasingly fails to connect the two.

This indicates that the limiting factor in offshore gas production has fundamentally shifted — from resource availability and connectivity to system architecture and operational flexibility.

Understanding this shift is essential for evaluating future offshore developments and for identifying the conditions under which existing approaches may no longer be sufficient.

Appendix – Supporting System Analyses

Appendix A

Norwegian Continental Shelf: Capacity-Constrained System

Appendix B

Southern North Sea: Infrastructure-Constrained System

Appendix C

Cross-System Failure Analysis

Operational, Economic, and Infrastructure Bottlenecks in North Sea Gas Production on the Norwegian Continental Shelf

Background and Focus on Near-Infrastructure Assets

The key distinguishing feature of “near-infrastructure” gas projects on the Norwegian Continental Shelf [\[1\]](#) is that value creation is not primarily determined by “more geology,” but rather by the **use (or non-use) of existing processing and export capacities**. The gas transmission system is a **regulated natural monopoly**: The state controls access, capacity management, and tariffs, with the explicit goal of ensuring **equal access** while simultaneously **setting tariffs** so that socially profitable projects do not fail commercially solely due to excessively high transmission costs. [\[2\]](#)

Furthermore: The system is large, but by no means “infinite.” For Norway’s gas pipeline network, approximately **120 billion Sm³/year** of dry gas transport capacity and about **8,800 km** of total length are cited; in addition, three central onshore facilities (Kårstø, Kollsnes, Nyhamna) are integrated into the pipeline architecture. [\[2\]](#) At the same time, throughput data show that capacity utilization and availability issues are real: Gassco [\[3\]](#) reported a record transport volume of **117.6 bcm** ($\approx 1,295$ TWh) for 2024—resulting, among other things, from debottlenecking at Kollsnes, stable field production, and high reliability of pipelines and terminals. [\[4\]](#) In a system that, in practice, operates close to record levels, **every new tie-in option** automatically becomes a matter of capacity rights, turnarounds, and bottleneck management—not just “reservoir presence.” [\[5\]](#)

A second structural point: The maturity of the shelf leads to a project portfolio that is **heavily satellite-oriented**. According to Norwegian authorities, as of the end of 2025, **91 discoveries** in or near mature areas were “under consideration for development”; most of these are small and intended as satellite developments to existing fields. [\[6\]](#) It is precisely this setup that explains why ORLEN Upstream Norway, Equinor, Aker BP, and Harbour Energy (following the acquisition of the Wintershall Dea portfolio) are strategically focusing on near-infrastructure resources: one can—if *capacities and host constraints align*—develop faster, more cost-effectively, and with less surface infrastructure. [\[7\]](#)

Tie-back limitations as technical and economic “tipping points”

Technical limits: Distance is only the visible trigger

With subsea tie-backs, there are hard physical limits that manifest in practice as **requirements for temperature, pressure, hydrate/wax management, and operational control (shutdown windows)**. For “long-distance tie-backs,” a Subsea 7 technology overview specifies a clear threshold: **>50 km (oil-dominated) or >100 km (gas-dominated)**, beyond which conventional flow assurance methods (insulation thickness, traditional inhibitor logistics/branch lines) either **reach their technical limits** or become **economically prohibitive** (e.g., costs of chemical injection lines). [\[8\]](#)

In the reality of North Sea near-infrastructure, most tie-backs are significantly shorter—but the **same mechanisms** are already at work on a smaller scale as soon as (i) cold/wet flows, (ii) high water content, (iii) CO₂-rich gases, or (iv) “low-pressure” operation at the host come into play. Examples:

- Utgard [\[9\]](#) is connected to the Sleipner system as a 2-well subsea template; the stream is treated at the host for CO₂ reduction, among other purposes. [\[10\]](#)

- At Utgard, **high water production** is explicitly cited as the current key production conflict—a classic issue that exacerbates separation/handling challenges, corrosive loads, and flow assurance risks. [\[11\]](#)

- At Gina Krog [\[12\]](#), **ongoing modifications** are underway to prepare for **low-pressure production** as well as explicitly for **tie-in preparation** for Eirin. This is practically the hallmark of hosts themselves (pressure regime/compression/topside margins) becoming tie-back limiters. [\[13\]](#)

Another major technical trend: **hydrate prevention via MEG/chemical inhibitors**. The expansion of MEG regeneration capacity at the Kollsnes gas processing plant was justified by Equinor (as a technical service provider for Gassco) and others as a means to support **long-term regularity and maximum capacity**; MEG is explicitly described as a means to combat **hydrate formation and corrosion** in pipelines. [\[14\]](#) This is a concrete indication: It is not only pipeline diameter or distance that imposes limits, but **upstream-proximate chemical/regeneration chains** at the process node.

Economic limits: “perceived-as-cheap” is relative—and does not scale linearly with volume

Tie-backs are often portrayed as “cost-effective,” but in specific NCS field projects, it is evident that **even small volumes can trigger billions in CAPEX** as soon as new subsea hardware, pipelines, umbilicals, and host modifications are required:

- Eirin [\[15\]](#) (2-well subsea template, tie-back to Gina Krog, ~10 km distance from the host structure) has **2,619 million NOK** in historical investments through the end of 2024, with an additional **1,966 million NOK** in planned investments (total ~4.6 billion NOK). [\[16\]](#) ORLEN estimates the reserves for Eirin at around **27 million boe**, >85% of which is gas. [\[17\]](#)
- Utgard shows **2,371 million NOK** in historical investments plus **597 million NOK** in future investments through the end of 2024. [\[18\]](#)

This can be formulated as a pattern (derived from the cases mentioned):

Above a certain “minimum hardware threshold” (new template + new flowline/umbilical + host modifications), the cost base becomes so high that 5–10 million boe discoveries are only robust if the residual uncertainty (reservoir/flow assurance/host) is low and integration succeeds without major host modifications. This conclusion is consistent with the observation that, for very small discoveries near the host (Frida Kahlo in the Sleipner license area), Equinor explicitly attempts to **“well-to-stream” path extremely short**: Frida Kahlo (Sleipner B) is scheduled to go into production as early as April—this is the archetypal “minimal incremental facilities” approach. [\[19\]](#)

Marginal field economics at 5–30 million boe

How “small/medium” is actually calculated on the NCS

In practice, near-infrastructure fields on the NCS are not calculated as an isolated NPV exercise, but as a **portfolio and hub optimization problem**:

- **Incremental CAPEX** (subsea + host modifications + tie-in pipelines + power/control upgrades if applicable) versus **Incremental Netback** (gas price, condensate revenues, tariffs/Gassled costs, CO₂ costs, OPEX add-ons). [\[20\]](#)

- Additionally: **Option Value** (host lifespan extension / avoidance of decommissioning triggers) and **regularity/outage risk** (a host event affects multiple satellites simultaneously). [\[21\]](#)

The Norwegian cost perspective underscores the scale: For 2025, “overall costs” of just under **NOK 390 billion** are cited, of which ~60% are investments; at the same time, it is emphasized that even

smaller offshore projects are on the scale of “major industrial investments” and that cost estimates are highly uncertain. [22] This is the economic rationale behind why small fields are often **postponed** in reality when the cost front (EPC/rig rates/topside modifications) is unfavorable.

Why projects are delayed, deprioritized, or abandoned

Aker BP provides a particularly clear real-world signal regarding the formal PDO process: After submitting a PDO, licensees must declare within three months whether they will “accede” to the plan or not. [23] The same announcement documents a specific reason for cancellation: The Trolldhaugen project (Edvard Grieg Area) was **not** signed because an Extended Well Test since 2021 led to lower expected recoverable volumes and the project “no longer had sufficient financial robustness.” [23] This is the typical marginal field killer in mature areas: **performance uncertainty + cost base + tight robustness margins**.

At the same time, the cost side cyclically intensifies the selection pressure: According to Westwood, the subsea EPC cost index in 2025 was about **25% higher than in 2021** (amid simultaneous macro headwinds). [24] For near-infrastructure fields, this means: When the “perceived-as-cheap” variant (standard tie-back) drifts toward the price range of a “complex brownfield modification,” small volumes will be the first to be pushed out of the portfolio.

Another useful anchor for OPEX robustness is the operators’ operational benchmark rhetoric: Aker BP explicitly positions itself as a peer benchmark with **<7 USD/boe** “lowest operational costs.” [25] In an environment where many near-infrastructure tie-ins are attractive precisely because they are not expected to worsen unit costs, any tie-in option that noticeably increases **additional host OPEX** (chemicals, compression capacity, maintenance intensity, turnaround duration) quickly becomes a “non-robust” decision.

Infrastructure bottlenecks in hubs, processing, compression, and export

Bottleneck logic: capacity, quality, pressure level—not just “free slots”

NCS gas value creation is dominated by a series of specific nodes through which near-infrastructure assets “must pass through”:

- Kollsnes gas processing plant[26]: Authorities cite a capacity of up to **143 million Sm³/day of rich gas**. [27] Equinor describes upgrades that have increased capacity from **144.5 to 156 million Sm³/day**; this is cited as a key driver for the Troll production record in 2024. [28]
- Kårstø gas and condensate processing plant[29]: approx. **95 million Sm³/day of rich gas** capacity plus significant condensate/NGL capacities. [27]
- Gas export hubs such as Draupner serve as hubs for **blending** and export under **specified pressure/volume/gas quality**—in other words: quality specifications and pressure management are real system constraints. [30]

For near-infrastructure assets, it is crucial: It is not enough to connect “somewhere.” The gas must be **quality-compliant** (e.g., CO₂ content) and **pressure-compliant** (compression window, backpressure) to fit into the export logic.

The Sleipner cluster as an example of “processing constraints” rather than “pipeline length”

Sleipner[31] is a textbook case because several types of bottlenecks converge here: gas export via Gassled, condensate/unstable oil toward Kårstø, and an additional role as a transit/hub in the system. [32] While nearby infrastructure developments are geographically favorable there (Utgard ~20 km, Alfa Nord ~18 km pipeline), the economic reality lies in **processing and operation**:

- Sleipner Øst explicitly describes the role of Sleipner T for **processing and CO₂ removal** and lists several tie-in fields (including Utgard) connected to it; CO₂ is injected into a formation via a dedicated solution (Utsira) . [\[33\]](#)

- Utgard is tie-back-capable precisely because CO₂ reduction is available at the host—at the same time, high water production increases the operational/processing load. [\[11\]](#)

Troll Cluster: Compression, Plant Debottlenecking, and Reliability

Troll[\[34\]](#) illustrates that “more gas” in the North Sea today comes primarily through **compression + processing + availability**. Troll’s field description explicitly states that the **gas compression capacity** at Troll A was increased in 2004/2005 and again in 2015—a sign that pressure management/compression must be retrofitted as a bottleneck. [\[35\]](#)

Equinor explicitly attributes the Troll record of 2024 (42.5 bcm) explicitly to **high regularity without turnarounds**, efficiency upgrades, and, among other things, riser replacement at Troll B—that is, to asset integrity and availability work, not to “new major discoveries.” [\[36\]](#) At the same time, the increased Kollsnes capacity is cited as a necessary export/processing condition. [\[28\]](#)

Harbour Portfolio Perspective: Gjøa as a “Reserved Capacity” Bottleneck

Following the completion of the Wintershall Dea portfolio acquisition (transfer/completion September 2024), Harbour Energy has a Norway portfolio that is heavily based on **hub-and-spoke tie-backs**. [\[37\]](#) This becomes operationally apparent at the Gjøa[\[38\]](#) hub: Harbour itself describes Gjøa (non-operated) as the largest hub in Norway; Nova[\[39\]](#) and Vega[\[40\]](#) are tie-backs to it. [\[41\]](#)

The decisive infrastructure constraint is clearly documented on the NOD fact pages: “**Production from Nova is in accordance with the reserved capacity at the Gjøa processing facility.**” [\[42\]](#) This is the operational reality of near-infrastructure gas: It’s not a matter of “there’s a pipeline,” but rather **there’s reserved processing capacity**—and whether that reservation is compatible with the other satellites and the host operation.

Age and integrity risks: central nodes as systemic single points of failure

The more satellites are connected to a few hubs, the greater the systemic impact of outages. A real-world example: In 2024, gas transport at the Sleipner riser node had to be partially shut down due to pipe damage; repairs were expected to take several days. [\[43\]](#) This is precisely the risk that is often underestimated in marginal field economies: **a single hub incident can “strand” multiple tie-ins simultaneously**, which reduces the expected availability (and thus the economic value) of small fields.

Time and Decision Bottlenecks from Discovery to Production

The Norwegian government estimates the average lead time on the shelf at **11 years from discovery to production start**; small discoveries near infrastructure could often be connected faster—but only **if capacity is available**. [\[44\]](#)

The gap between “can be fast” and “is fast” is extreme on the NCS—and this is precisely where real bottlenecks arise:

- **Fast-track examples (when the host window is open):** Equinor cites the goal of “on stream in two to three years” for the Lofn, Langemann, and Sissel discoveries; furthermore, Frida Kahlo (from Sleipner B) is already scheduled to go into production in April. [\[19\]](#)

- **Multi-decade examples (when portfolio/host/economics do not align):** Eirin was discovered in 1978, PDO approval in 2024, production start “planned for 2026.” [\[45\]](#) Utgard: Discovery 1982, PDO 2017, Start 2019. [\[10\]](#)

From an operator’s perspective, the sources of delay are generally **not geological**, but rather procedural/organizational:

1. **Partner alignment within the license syndicate:** As soon as a field development decision is made, a PDO must be submitted to the ministry; thereafter, license partners must declare within **three months** whether they will join. [\[46\]](#)
2. **Brownfield engineering and shutdown windows:** Modifications are often deliberately scheduled during planned maintenance shutdowns to minimize production losses—this is good for revenue from existing production, but can “lock in” and delay tie-ins. [\[47\]](#)
3. **Regulatory IA obligations:** A PDO must cover impact assessment content (including environmental and project description). [\[48\]](#)

The pattern: **Time is a scarce production factor** because host capacity, turnaround windows, and partner decisions must be synchronized; the smallest projects suffer the most because, in case of doubt, they do not generate “time pressure” through large volumes.

Risk and uncertainty factors that can derail near-infrastructure projects

Market and price risk: Gas has become more volatile—and LNG sets the marginal prices

The International Energy Agency [\[49\]](#) reports that, while gas price volatility in Europe has calmed down following the Russian pipeline shock compared to the extremes of 2022/23, it will still be **~50% above the 2010 –2019 average**. [\[50\]](#) This aligns with the EU import structure: LNG’s share of total EU gas imports is projected at **~45%** for 2025, which reinforces price sensitivity to global LNG marginal volumes. [\[51\]](#)

For NCS near-infrastructure assets, this means: Even if CAPEX appears low, the project is highly sensitive to **short-term netbacks** (price + transport tariffs + availability), because volumes are small and the payback period often needs to be kept short. [\[52\]](#)

Regulation & CO₂ Costs: Emissions pricing is a real cash flow driver

Norway combines a CO₂ tax and the EU ETS for the petroleum sector; an effective price level of **~NOK 1,565 per ton of CO₂** is cited for 2024. [\[53\]](#) This has a direct impact on tie-backs, because additional compression, chemical handling, and longer production routes can drive energy consumption and thus emissions—unless the assets are electrified (power-from-shore). [\[54\]](#)

Added to this are the fiscal mechanics: The marginal petroleum tax rate is **78%** (22% CIT + Special Tax; technically adjusted to maintain 78% in a cash-flow system). [\[55\]](#) While the system can cushion investments fiscally, it simultaneously increases the need for projects to be **formally and transparently** robustly justified (PDO review, IA obligations). [\[56\]](#)

Technical risks: Water, CO₂, hydrates – and human operational discipline

According to SPE/JPT, the relevance of flowline blockages (hydrates/paraffins) increases with longer tie-backs; chemical injection is effective but can become **logistically difficult and expensive**, and single-line concepts are gaining importance, among other reasons, due to the costs of dual flowlines. [\[57\]](#) In the NCS context, this is particularly relevant because central hubs (Kollsnes/MEG

regeneration, Sleipner processing) influence many satellites simultaneously as shared infrastructure services. [\[58\]](#)

Operators' Strategic Behavior and Identification of Economic "Gaps"

Why Near-Infrastructure Is Prioritized

The strategic rationale is unusually directly stated in the sources:

- ORLEN explicitly describes Sissel as confirmation of an exploration strategy "close to existing installations," because it enables **rapid start-up** and **significantly reduced investment costs**; Furthermore, Sissel is intended to compensate for the decline in Utgard and thereby extend the infrastructure's lifespan. [\[59\]](#)
- JPT describes long tie-backs as attractive because they enable **fast-tracked projects**, enhance the value of existing infrastructure, and stabilize throughput at the host as old wells decline. [\[60\]](#)
- Norwegian regulatory logic emphasizes that the resource base of existing facilities grows through tie-ins from small neighboring discoveries and that spare infrastructure capacity in mature areas must be utilized for new resources. [\[61\]](#)

Partnerships as Decision Gates (and Accelerators)

Near-infrastructure is partnership-driven because the host operator, process nodes, and pipeline access are often located in **other** licenses/BAA structures. Specific examples: - Sissel is a 50/50 joint venture between ORLEN Upstream Norway and Equinor, with Equinor as the operator; development is explicitly

"subject to partners' decision after economic/technical/operational evaluation." [\[62\]](#)

- Lofn/Langemann were discovered "together with partner Aker BP" and are designated as subsea tie-backs with a 2–3-year target—meaning partners must not only say "yes" but also synchronize host capacities and engineering windows. [\[19\]](#)
- Harbour documents Gjøa as the largest hub; Nova/Vega are tie-backs—but production is aligned with **reserved processing capacity**. This is partnership not as a "nice-to-have," but as strict capacity governance. [\[63\]](#)

Recurring Structural Inefficiencies

Recurring bottlenecks can be identified from the specific cases, which repeatedly lead to "economic gaps" in mature fields (gas technically available but not realized economically/operationally):

Host lifespan vs. satellite timing (decommissioning cliff). Sleipner Øst is in late-tail production; at the same time, operations for tie-back fields are expected to continue. This inevitably results in a cliff: If the satellite pipeline is delayed (partner decision, CAPEX cycle, conversion shutdowns), the risk increases that the host infrastructure will be shut down before amortization or its flexibility will be restricted. [\[64\]](#)

Reserved capacity as a bottleneck, not a formality. Nova is explicitly operated "in accordance with reserved capacity." This is the pattern for many satellites: even if pipeline connection is possible, processing/compression at the host can only be run within reserved/technical limits—and new discovery volumes can thus effectively "sit idle." [\[65\]](#)

Shared-service bottlenecks (MEG/CO₂ removal/low-pressure mods) . Kollsnes required MEG handling upgrades; Gina Krog requires low-pressure and tie-in modifications; Sleipner T is a central

CO₂ removal component. These bottlenecks are structural because they are *more likely* to be exacerbated by satellite growth: every new tie-in source increases the load on shared services. [66]

Systemic outage risks at central hubs. The Sleipner riser incident in 2024 demonstrates that integrity events at a hub do not remain localized. For small fields, this means: uncertainties in the annual uptime profile have a disproportionate impact on project value because the absolute margin is small. [67]

Conditions under which “alternative concepts” become economically viable

When classic tie-backs fail (distance/temperature/shutdown window), alternative concepts become relevant—but only under clear conditions:

- **Long-distance gas tie-backs >100 km** require, according to Subsea 7 logic, non-conventional flow assurance strategies (active heating, cold-flow concepts, subsea boosting), because traditional methods are no longer viable either technically or cost-wise. This can make *previously uneconomical* prospects viable in the first place, but shifts CAPEX/OPEX into new categories (power, controls, subsea processing). [68]
- **If the export/processing system operates near record capacity utilization** (117.6 bcm in 2024) and the nominal system capacity is ~120 bcm/year, additional production will realistically only be possible through debottlenecking investments and increased availability (example: Kollsnes capacity expansion). [69]
- **CO₂ Costs and Electrification Business Case:** Electrification is explicitly positioned as a lever to enhance competitiveness and extend field life (reduce CO₂ costs, extend field life). If tie-ins avoid additional absolute emissions (higher throughput with similar emissions) or are connected to electrified hosts, this improves the robustness of marginal fields. [70]

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Systemic bottlenecks in gas production in the southern North Sea between the UK and the Netherlands

Network logic and critical nodes

The offshore corridor under consideration between the UK and the Netherlands is limited less by a “lack of pipelines” than by a **chain of gathering/hub platforms, conditioning (dewpointing/dehydration), hydrate management (MEG), pressure regimes (compression), and the transition into respective national transmission networks**. In a mature basin like the Southern North Sea (SNS), gas is therefore often **geographically close** to infrastructure but remains **systemically disconnected** because the bottleneck is *not* distance but *an operating condition* (e.g., pressure, specification, capacity rights, host lifespan).

On the UK side, the key node is the terminal cluster around Bacton Gas Terminal^[1]: It bundles several operator terminals (including Shell, Perenco, and historically Eni) and simultaneously serves as a connection point to two European interconnectors (Bacton–mainland and Balgzand–Bacton).^[2] On the Dutch side, the Den Helder^[3] line (onshore treatment/export) and the offshore trunks WGT/NGT/NOGAT are central; these connect private offshore transport systems to the national transmission network, which is operated by Gas Transport Services B.V. (GTS)^[4] (Gasunie Group).^[5]

A key structural issue underlying the problem (“The gas is there and technically recoverable, so why isn’t it flowing?”): **Even though export pipelines/border interconnection points have large nominal capacities, they do not resolve the upstream bottlenecks** (dew point/water spec, hydrate window, minimum pressure at entry, host availability, contractual rights). This is the typical SNS “close, but no cigar” mechanism.^[6]

Hub and infrastructure bottlenecks: processing, compression, export

Bacton as a cluster of bottlenecks: processing capacity, lack of onshore compression, MEG as a critical service

The Bacton system is not a single “terminal,” but a **multi-terminal cluster** with varying technical capabilities and dependencies:

- **Shell terminal (Bacton):** Gas treatment capacity **900 mmscfd** and liquid capacity **5,000 bbl/d**; Conditioning via propane refrigeration system (removal of liquids/water). Crucially: The terminal has **no onshore gas compression**; the feed is “balanced” via the pressure level of the UK National Transmission System. In practical terms, this means: If offshore sources (especially late-life/low-pressure) can no longer provide the required inlet pressure, Bacton cannot “make up” the difference—the compression load lies upstream/offshore.^[7]
- **MEG Regeneration/Distribution:** The Shell terminal includes facilities for regenerating MEG, which is explicitly required for **hydrate inhibition** in the onshore pipelines. If this chain (or the MEG supply line) fails, this is not an “OPEX detail,” but can **immediately limit throughput**.^[7]
- **Perenco Terminal (Bacton):** Dew point/processing capacity is described as a maximum of **750 mmscfd** and is supported by a **single gas compressor** (“single compressor”). This is a classic SNS bottleneck: even if raw gas physically arrives, conditioning/compression can be the bottleneck—plus the “single point of failure” characteristic.^[7]

- **Terminal consolidation/asset decommissioning:** The Bacton overview explicitly mentions that the former Eni terminal was integrated into the Perenco terminal in 2011 and that two Eni pipelines are “now disused.” This is a real-world example of how, in mature gas markets, infrastructure not only ages but **actually disappears or consolidates**, causing “nearby” assets to lose their nearby connection points.[\[8\]](#)

Offshore feeder systems to Bacton: nominal pipeline capacity is not the same as usable capacity

The Bacton network map lists specific feeder systems along with their capacities (mmcfd), thereby showing how heavily the system is segmented into **sub-networks** (Leman West, Leman East, Inde Area, ETS, etc.). Examples: Leman West System **900 mmcfd**, Leman East Area **600 mmcfd**, Indefatigable Area **700 mmcfd**, Esmond Transportation System (ETS) **400 mmcfd**.[\[8\]](#)

Important for bottleneck analysis: These values are **design/nominal capacities**. Actual limitations often occur as a combination of: * **Processing limit at the receiving terminal** (dewpointing/dehydration/MEG availability), [\[7\]](#)

Pressure/backpressure limit (especially without onshore compression at the entry point),[\[7\]](#)

Integrity/availability (repairs, freespan, turnarounds),[\[9\]](#)

*Contractual rights/capacity allocation** (see below).[\[10\]](#)

Cross-border export/import pipelines: large, but not the bottleneck “before the terminal”

Between the UK and the Netherlands, the interconnectors at Bacton are particularly relevant. Bacton documents indicate an import capacity across both European lines (“UK-Continent Interconnector” and BBL) of **>3,000 mmcfd**, and describe that these lines now operate **highly seasonally** (summer tends to be export to the continent, winter tends to be reverse).[\[11\]](#)

At the same time, regulatory documents show that the capacity actually available *also* depends on market rules/exemptions: The BBL interconnector had a (temporary) **exemption from third-party access/charging obligations**, with a capacity at that time of **1.75 million m³/h (≈15 bcm/year)** toward the UK. This is a critical systemic issue: infrastructure may physically exist, but **cannot freely serve as a relief valve** for offshore gas if the access/capacity mechanism is restricted. [\[12\]](#)

Tie-backs and satellites: practical limits in the SNS are pressure, specifications, and brownfield windows

Distance is rarely the limiting parameter—but “long tie-backs” present significant flow assurance challenges

For the SNS (flat, densely populated), many satellite connections fall within the typical range of a few to several dozen kilometers.

Nevertheless, it is helpful to recognize the documented long-distance thresholds as “tipping points”: Subsea7 defines “long-distance tie-backs” as **>50 km (oil-dominated) or >100 km (gas-dominated)**; beyond these distances, conventional flow assurance methods are often no longer feasible—either due to technological limitations (insulation thickness) or because **costs for ancillaries such as chemical injection lines** make the project economically unfeasible.[\[13\]](#)

In the SNS, this tipping point is usually not reached by distance alone, but rather by a **combination of lower pressure (late-life), higher water content, stricter specifications, and a lack of redundancies** (MEG, compressor, dewpointing train). [\[14\]](#)

SNS-specific tie-back limits: “Entry pressure” and “Gas Spec” as non-negotiable system parameters

Two specific mechanisms repeatedly make tie-backs in the SNS unattractive or technically blocked despite “proximity”:

1. **Minimum pressure at entry / lack of onshore compression:** If a terminal (such as Shell-Bacton) lacks onshore compression and feed-in occurs at the NTS pressure level, low-pressure gas is effectively blocked unless upstream/offshore compression is retrofitted.[\[7\]](#)
2. **Specification chain: Dewpointing/Dehydration/MEG:** Perenco-Bacton specifies a maximum dewpointing capacity based on a single compressor; Shell-Bacton describes the conditioning process, including MEG regeneration (hydrate inhibition). Such services are often the actual bottleneck resource for satellites, not the “free pipeline.” [\[15\]](#)

Case study: Tie-back “technically feasible,” but economically/contractually limited by host tariffs and brownfield modifications

A well-documented SNS case is the Phase 1 Anning/ Somerville (Hartshead): The concept is based on a new subsea pipeline that connects to **underutilized Shell infrastructure** at a host platform; the gas is then to be delivered to Bacton for processing and into the UK transmission network.[\[16\]](#)

The systemic implication lies in the cost and contractual assumptions: In addition to direct OPEX, **“third-party charges” for transport and processing via Shell infrastructure** are explicitly mentioned; these tariffs are said to be “likely gas price linked.” Thus, monetization depends not only on the gas price but also on the **host’s tariff regime**—a typical SNS bottleneck that can slow down or derail projects even when pipeline “proximity” exists.[\[16\]](#)

Marginal field economics in a mature SNS system: why “small” doesn’t scale

Production profile: many fields, few carry the throughput—and that is precisely what generates fixed system costs

For the Bacton Catchment, it is reported: **>30 onstream fields**, but **6 fields supply ~2/3 of daily production** (2022). Fields mentioned include Cygnus, Barque, Galleon, and Elgin/Franklin streams. This is the typical mature basin profile: many assets have gas, but only a few keep system throughput high.[\[17\]](#)

The consequence is systemic: as soon as the major producer fields decline, **fixed O&M costs per unit** rise in terminals, hubs, and service chains

(MEG, utilities, inspection, corrosion management). This undermines the economic viability of new small tie-backs, even if CAPEX appears “relatively low.”[\[18\]](#)

Aging/integrity as a genuine production barrier (not just “more maintenance”)

Two robust, documented examples from the system under consideration:

- The Bacton FOS FEED describes **integrity and operational issues** at the National Grid portion of the site due to age and coastal location; a “significant program of asset replacement” is mentioned. This is not merely cosmetic: integrity and obsolescence limit availability and raise the threshold at which operators decide to continue operating or rationalize infrastructure.[\[19\]](#)
- At the pipeline level, a specific case demonstrates how “pipeline geotechnics” becomes a genuine system bottleneck: The Bacton-Leman-MEG pipeline (PL121) suffered a **full-bore rupture** in 2021 due to free span formation and movements caused by wave currents; it lies

in the same trench as the 30" gas pipeline PL25. Such events are operational production stoppages or risk-based throughput constraints because hydrate management and export capacity are linked.[\[20\]](#)

Dutch side: Compression is the dominant energy and OPEX driver – and late-life operation degrades efficiency

For the Dutch offshore gas industry, a PBL analysis describes that gas turbine-driven centrifugal compressors are typical (installed capacity up to **~70 MWth input**) and that compression typically accounts for **70–85%** of the energy input offshore. As production rates decline, the turbines/compressors become oversized, operate away from the best-efficiency point, and must be “restaged” to maintain performance.[\[21\]](#)

In terms of bottleneck logic, this means: In late-life phases, “gas is available” can still mean that **compression costs and availability** become the limiting factor; without compression, export pressure cannot be maintained; with compression, fuel consumption, OPEX, and emissions increase.[\[22\]](#)

Additionally, dehydration is not “optional”: Compression is followed by dehydration to meet water content requirements specified by pipeline systems or transport/sales contracts. This is a hard specification bottleneck for marginal flows.[\[21\]](#)

System-Level Bottlenecks and “Economic Gaps”: Gas Available, Infrastructure Nearby – But No Flow

The following cases/patterns are deliberately formulated to make the blockage **concrete** (what is blocking?), and to separate the cause into **physical / operational / contractual / economic** categories.

Shut-ins in existing hub networks (UK SNS): Flow is halted even though export routes exist

An environmental/operational report on UK SNS hubs (Perenco operations) lists several actual shut-ins within active export networks:

- At the Inde hub, the Davy platform and its subsea infrastructure have been **shut in since 2020**, even though the hub exports gas/condensate to Bacton via Leman-27B (PL22).

Blockers: operational/technical (shut-in asset in the hub network), typically combined with economic considerations (workover/repair vs. residual value).[\[23\]](#)

- The Durango subsea well is described as a **third-party tie-back** to the Waveney installation and has been **shut in since 2019**. **Blockers:** operational (shut-in), plus systemic: Third-party tie-backs are additionally subject to host priorities and service windows.[\[23\]](#)
- In the Leman hub, a subsea well (Leman South West) has been **shut in since 2020**; the hub continues to export to Bacton (PL23). **Blockers:** operational/technical within the subsystem; the main export pipeline is not the limiting factor, but rather the late-life source chain.[\[23\]](#)
- Trent “has not operated since 2021,” although the export route (EAGLES/PL253) to Bacton is described. **Blockers:** operational (asset decommissioned).[\[23\]](#)

These cases reveal a recurring pattern: In mature hub networks, “stranded gas” is often not a new discoveries problem, but a **brownfield integrity and prioritization problem** within an existing system.

“Near infrastructure” projects dependent on contract/tariff frameworks (UK SNS)

The Hartshead example illustrates why gas does not enter “the system” despite technical recoverability: The project logic relies on a tie-in to Shell infrastructure and Bacton processing, but

monetization must (i) secure **binding host agreements** and (ii) bear **third-party tariffs**, which may even be gas-price-indexed. **Barriers:** primarily contractual/economic (tariffs, negotiation, risk of terms), secondarily organizational (timing of FEED, FDP/regulatory steps, host brownfield modifications). [\[16\]](#)

Additionally, the existence of a separate regulatory dispute resolution system for third-party access in the UK is an indirect but strong indication that such conflicts actually arise as time/decision bottlenecks: The North Sea Transition Authority [\[24\]](#) has explicit powers for this purpose (Energy Act 2011), which also encompass services such as metering/allocation and even host utilities (fuel/power for third-party equipment); onshore terminals are within the scope. **Blocking factor:** systemic/organizational (negotiation + dispute resolution as a gate). [\[10\]](#)

Countdown effect due to infrastructure lifespan: “Infrastructure is there” – but only until a certain date

The Bacton FOS FEED sets a firm expectation: In the 2030s, it is planned that interconnectors will become the **sole** gas supply path to Bacton, “with the cessation of gas supply from the South North Sea”; a switchover point around **2035** is used for the study planning.

At the same time, it is described that Option 2 (rationalization) would only be applicable after the end of these SNS flows and even assumes the “abandonment of Shell and Perenco assets.” **Blockers:** systemic/economic (host lifespan and rationalization), not geological. [\[25\]](#)

This is one of the most significant structural inefficiencies of mature offshore systems: **the existence of infrastructure is time-limited**, and small fields often fail to make it through engineering windows, negotiations, and the FDP process in time—even if they were technically connectable.

Dutch perspective: Privately operated offshore trunks + gas quality splitting as “invisible” barrier

For NL Offshore, it is crucial that gas is transported offshore primarily via **privately owned** transport systems to land and only then connects to the national grid (Gasunie/GTS). The three main systems are WGT, NGT, and NOGAT. **Barrier:** organizational/contractual, because access is not automatically “TSO-like” but operates through private infrastructure regimes. [\[26\]](#)

The NL-EITI reporting also shows that stakes in offshore pipeline systems (e.g., WGT/NGT extensions) are structured as **contractual partnership arrangements**—i.e., contractual consortium logic rather than classically regulated open-access logic. **Barrier category:** contractual (partner rights, tariffs, allocation). [\[27\]](#)

Added to this is gas quality: A TNO report explicitly states that a LoCal pipeline (NP007) transports low-cal gas from specific wells and is operated by NAM; NOGAT (TP-001) and the onshore treatment facility in Den Helder have limited processing capacities (e.g., “can handle up to **36 million Nm³/day**” for the Den Helder plant according to NOGAT data; NGT Uithuizen plant “up to **50 million Nm³/day**”) **Barriers:** physical (train capacity) + specification (HiCal/LoCal segmentation) + organizational (operator/owner responsibilities). [\[28\]](#)

Decommissioning as “removal of the connection option” (UK perspective, Harbour reference)

Harbour itself documents that production in the Viking Area cluster ended in 2016 and decommissioning is nearly complete (platforms removed, wells P&A). This is the most severe case of “nearby infrastructure” illusions: In a mature system, the supposedly nearby host infrastructure may **already be gone**, meaning that even technically recoverable smaller volumes can no longer be monetized. **Blockers:** systemic (decommissioning/host gone). [\[29\]](#)

Time, decision-making, and organizational bottlenecks, as well as conditions for alternative off-take routes

Typical timeline: Tie-back can be fast—but only if the host, contracts, and window align

For UK projects, an average time of **~5 years from discovery to first production** is cited (via NSTA-referenced analyses), *provided* tie-back

routes are available. This is a best-case scenario for infrastructure-led development.[\[30\]](#)

However, the actual SNS delay profile usually arises at three points:

1. **Commercial/TPA negotiations** (tariffs, ullage, liabilities, gas quality, fuel/power at the host). The fact that the UK has dispute resolution rules and a formal process for this shows that this phase is a real gate.[\[10\]](#)
2. **Brownfield engineering and integrity work on the host/export path** (e.g., repair/remediation of pipelines; obsolescence and asset replacement at terminals).[\[9\]](#)
3. **System lifespan/decommissioning hurdles**: When a hub is moving toward rationalization/abandonment (Bacton scenario from the mid-2030s onward), the remaining time for new satellites becomes the limiting factor.[\[25\]](#)

Strategic Behavior: Why Near-Infrastructure Is Still Being Explored

Despite the maturity level, operators continue to explore near-infrastructure because—if successful—there are three key advantages:

- **CAPEX reduction through reuse and shorter cycle times** (instead of greenfield projects) . This logic is also politically/regulatorily relevant in the UK, as tie-backs are seen as a way to bring already discovered resources into existing systems.[\[31\]](#)
- **Throughput stabilization and extension of terminal/hub lifespan** (economics of fixed costs). This is precisely why Bacton “optimization” and rejuvenation investments are a recurring theme.[\[32\]](#)
- **Portfolio reshuffle via M&A**: The Viaro deal (acquisition of a Shell/ExxonMobil SNS portfolio) illustrates the strategy whereby independent operators seek to extend the economic residual value phase through changes in ownership/operatorship; the assets “tie back” to Bacton via Leman/Clipper.[\[33\]](#)

On the NL side, the strategy is more strongly shaped by **small-fields policy and network integration**: GTS has explicit responsibilities for ensuring sufficient transport capacity and tasks related to “small-fields policy”—while offshore transport up to landfall is organized privately. This favors near-infrastructure decisions but makes success heavily dependent on private offshore trunks and treatment nodes.[\[26\]](#)

Conditions under which existing systems fail and alternative off-take concepts “suddenly” become relevant

Without outlining solutions, the failure conditions can be precisely formulated: Alternative off-take routes/parallel transport only become economically or operationally imperative when at least one of the following conditions is met (typically an SNS-mature system):

- **Pressure regime mismatch**: The entry system cannot compress (Bacton Shell) or offshore compression becomes a dominant energy/OPEX bottleneck in the late life of the field; fields fall below minimum pressure → gas remains in the reservoir despite proximity.[\[34\]](#)

- **Processing bottleneck + low redundancy:** Dewpointing/dehydration/MEG are at capacity or have single-point-failure characteristics (one compressor, one MEG train, one critical pipeline). In this case, additional production cannot be monetized but only increases availability/shutdown stress.[\[15\]](#)
- **Host lifespan/decommissioning countdown:** If operators/network planners assume that SNS inflows will cease in the 2030s and host assets will be rationalized or abandoned thereafter, late tie-backs are structurally dead—infrastructure is geographically close but no longer available in terms of timing. [\[25\]](#)
- **Contractual barriers or tariffs kill netback:** Gas-price-indexed or otherwise volatile third-party charges (transport/processing) can make margins so volatile for small fields that FID does not materialize despite technical feasibility.[\[16\]](#)
- **Access/exemption regimes prevent offloading via interconnectors:** If cross-border pipelines do not function as fully open “spare capacity” buffers (exemption/TPA regimes), “European connectivity” is no guarantee that offshore gas will be monetized more easily.[\[35\]](#)
- **Reuse shifts toward “long tie-back” technology requirements:** As soon as distance/fluid/temperature conditions shift toward long-distance tie-backs (>100 km gas-dominated), conventional flow assurance methods and ancillaries become expensive or technically impractical—even if a “hub on the map” appears to be nearby.[\[13\]](#)

Operator and system context: Classification of the mentioned actors within the congestion logic

- **Harbour Energy (UK):** Relevance in the bottleneck context primarily through **late-life assets and decommissioning decisions** (Viking Area decommissioning) and through the general SNS reality that smaller volumes are only monetizable as long as host infrastructure exists.[\[29\]](#)
- **Shell (UK/NL):** In the UK SNS system, primarily through **Bacton processing, the MEG chain, and offshore pipeline integrity** (e.g., PL121 rupture), as well as serving as a host for tie-in projects where third-party tariffs/agreements and brownfield modifications are the gateways.[\[36\]](#)
- **Neptune Energy / Eni:** Eni has completed the Neptune acquisition (portfolio excluding NO/DE), thereby further consolidating Eni’s SNS asset base and, consequently, its dependence on Bacton/SNS hubs and their contract/capacity logic.[\[37\]](#)
- **NAM:** On the Dutch side, NAM is systemically relevant because—in addition to its E&P roles—it is named as the operator of landfall/treatment facilities (e.g., the Den Helder treatment facility in the TNO presentation; as well as operations for various offshore producers).[\[38\]](#)
- **Gasunie / Dutch Offshore Infrastructure:** The central system point is the **separation between private offshore transport regimes (WGT/NGT/NOGAT) and the regulated national grid (GTS)**. Many of the “close but not in the system” cases arise at this interface due to capacity/contract mechanisms, specification requirements, and treatment capacity at landfall nodes. [\[39\]](#)

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Systemic Failure Conditions in North Sea Gas Systems

Analytical Framework and Definition of System Failure

This analysis addresses **system failure** in North Sea offshore gas production systems^[1]: situations in which **gas is present and technically recoverable, infrastructure is geographically close**, but **no stable, marketable gas flow** (“monetized flow”) is achieved. The focus is on *precise* failure conditions (thresholds/triggers), not on general “mature basin” narratives.

Two clearly distinct system types are examined:

- **System Type A (Capacity/Allocation System):** Norwegian Continental Shelf^[2] – large-scale, highly integrated gas export architecture with regulated access (natural monopoly) and high utilization. ^[3]
- **System Type B (Aging/Infrastructure Bottleneck System):** Southern North Sea^[4] between the UK and the Netherlands – a dense network of aging hubs/terminals in which *pressure regimes, processing redundancies, integrity, and decommissioning countdowns* limit monetizable production. ^[5]

The operational context (for observable response patterns) includes, among others, Equinor ASA^[6], Aker BP ASA, and ORLEN Upstream Norway AS in the Norwegian system, as well as Harbour Energy plc^[7], Shell plc^[8], Eni S.p.A. ^[9]/Neptune Energy Group Limited^[10], Nederlandse Aardolie Maatschappij^[11], and Gas Transport Services^[12] (Gasunie Group) in the British-Dutch system.^[13]

Failure taxonomy: four classes that actually overlap

Systems rarely “fail” in just one dimension. In practice, failure usually occurs as a **cascade**:

Physical/technical: Pressure levels, compression, flow assurance (hydrates/water), and specifications (CO₂, water vapor/hydrocarbon dew point) result in gas being present in the reservoir but **unable to be transported stably to the point of sale**. ^[14]

Infrastructure: Processing saturation, lack of entry compression, single-point-of-failure components, aging/integrity issues, and pressure loss due to numerous tie-ins render “nearby infrastructure” effectively **unusable** or only usable with unacceptable uptime. ^[15]

Economic: Marginal fields (typically 5–30 mmboe) become uneconomical as soon as CAPEX/OPEX/tariffs erode the expected netback margin or price volatility undermines robustness. ^[16]

Systemic/organizational: Reserved capacities, third-party access regimes/exemptions, JV misalignment, dependence on the host operator, and timing gates (shutdown windows, brownfield integration) lead to *delay spirals* that can result in permanent non-development by the end of a host’s lifespan. ^[17]

System Type A: Capacity and allocation failures on the Norwegian Continental Shelf

Physical-technical failure conditions

Pressure/compression failure at the host (late-life pressure regime): When the host system (hub/platform) no longer has sufficient suction/discharge windows for new satellites, “nearby” gas is

effectively blocked. That this is a reality on the NCS is already evident from the host evolution logic: In the case of Troll^[18], the compression capacity at Troll A was demonstrably expanded multiple times (2004/2005 and again in 2015)—an indicator that compression becomes a systemic bottleneck as soon as field and system pressure drop. ^[19]

Specification failure (CO₂/processing dependency): In the Sleipner^[20] complex, CO₂ management is not a “nice-to-have” but a prerequisite for bringing satellite streams to export. Official field information explicitly states that Utgard^[21] is connected to Sleipner T to reduce CO₂; CO₂ is injected into the Utsira Formation via Sleipner A. The failure threshold here is not distance, but **free processing slot/capacity for CO₂ removal**: If this capacity is lacking or fully utilized by existing streams, the gas remains technically recoverable but is not commercially “sales-gas-capable.” ^[22]

Flow assurance failure (hydrate window/MEG chain): The need to expand MEG regeneration at the onshore hub is a direct indication of systemic flow assurance constraints. For Kollsnes^[23], an MEG upgrade was explicitly justified by the need for hydrate prevention/corrosion protection in export/pipeline operations; at the same time, the plant is described as central to gas exports. Failure Condition: If MEG regeneration/logistics/export pumps or associated utilities are limited, additional satellite production is not released but instead increases the risk of trips/shutdown restrictions. ^[24]

Tie-back limits as a technological tipping point (for “long” satellites): For long-distance tie-backs, Subsea7 cites an industry-standard tipping point: **>50 km (oil-dominated) or >100 km (gas-dominated)** – beyond that point, conventional flow assurance approaches are often no longer feasible, or the costs of ancillary systems (e.g., chemical injection lines) make development prohibitive. In the NCS context, the practical threshold shifts earlier if host pressure/specifications/processing are already strained. ^[25]

Infrastructure Failure Conditions

Macro-capacity saturation: Transport system near design limit: Norwegian pipeline network capacity is reported at approximately **120 billion Sm³/year**. In 2024, **117.6 bcm** were delivered through the system to Europe—a near-record level in actual operation. Thus, “near infrastructure” does not automatically mean “free capacity”; rather, every new tie-in volume becomes an allocation and scheduling problem. ^[26]

Processing saturation at onshore hubs: Kollsnes is officially cited as having up to **143 million Sm³/day of rich gas**; Equinor describes upgrades that increased capacity from **144.5 to 156 million Sm³/day**—explicitly as a contribution to production records. This shows: Additional production actually requires debottlenecking at a few hubs; without this debottlenecking, “gas available” does not equate to “marketable.” ^[27]

Hub Quality/Pressure Gate (Draupner Function): Gassco^[28] describes the function of the Draupner platforms as blending/export hubs that deliver gas **at specified pressure/volume/gas quality** to the receiving end. Failure Condition: As soon as new flows exceed the specification or pressure envelope (e.g., more CO₂, more condensate/water, lower pressure), the hub function itself becomes the bottleneck—regardless of whether a pipeline is “right next door.” ^[29]

Single Point of Failure at Critical Connection Points: The crack incident at the Sleipner riser platform in 2024 led to shutdowns and reductions in gas transport and affected operations all the way to the onshore hub (Nyhamna impact mentioned in Reuters reporting). This is the worst-case scenario for a highly integrated system: A small integrity failure at a hub can “shut down” large upstream volumes and thereby also devalue satellite projects (because the uptime risk premium rises). ^[30]

Economic failure conditions (marginal gas despite infrastructure)

CAPEX surge due to “minimum hardware set”: As soon as a tie-back involves not just a short connection but requires a subsea template + flowline/umbilical + host modifications, a cost barrier arises that quickly overwhelms small volumes. Example: For Eirin[\[31\]](#), historical investments of **2,619 million NOK** plus **1,966 million NOK** (from 2025) are reported—a scale that remains robust for typical 5–30 mmbob developments only with very high certainty and stable netbacks. [\[32\]](#)

Volumetric uncertainty undermines robustness (stop threshold):

Aker BP documents the actual decision-breaking point for the Trolldhaugen project: Extended Well Test reduced expected recoverable volumes; the project is “no longer considered to have sufficient financial robustness,” hence no entry into the PDO. This is the concrete failure threshold: **If uncertainty + cost basis + time value loss erodes the robustness margin, development does not proceed—even though it is technically possible.** [\[33\]](#)

Price volatility as an NPV killer with a short remaining lifespan: The IEA shows: European gas price volatility in 2024 was still **50% above the 2010–2019 average**. In portfolio decisions, this squeezes marginal fields because short payback windows and host dependencies make cash flows “right-skewed risk.” [\[34\]](#)

Systemic-organizational failure conditions

Capacity allocation as a hard gate (reserved capacity): Nova[\[35\]](#) explicitly states: “Production ... is in accordance with the reserved capacity at the Gjøa processing facility.” This is not a semantic issue but a structural bottleneck: Gas can technically flow, but is “capped” **within reserved processing slots.** [\[36\]](#)

Access/Regulation and Tariffs (Natural Monopoly): The Norwegian system is described as a natural monopoly framework with regulated tariffs and government-controlled access; essential infrastructure is bundled via Gassled[\[37\]](#), with neutral operation by Gassco. Failure Condition: When access is formally possible but capacity is unavailable (or only available under conditions that devalue marginal projects), “near-infrastructure stranded gas” arises despite physical proximity. [\[38\]](#)

Timing Gate (Capacity Must Be Available at the Right Time): The Norwegian government’s presentation cites an average lead time of **11 years** from discovery to start-up; small finds near infrastructure can often be integrated more quickly—if **capacity is available**. This is the precise failure trigger: *capacity availability* is a necessary condition, not an assumption. [\[39\]](#)

Operational Behavior as a Symptom: ORLEN explicitly describes the “close to existing installations” strategy for the Sissel discovery, with tie-backs for a faster start-up and lower investment; at the same time, the discovery is intended to compensate for declines in the Utgard system and extend the infrastructure’s lifespan. This is a direct response to failure risks: operators are not chasing “more gas,” but rather **greater throughput stability in the existing system.** [\[40\]](#)

System Type B: Aging and Infrastructure Failure in the Southern North Sea (UK–NL)

Physical-Technical Failure Conditions

Entry pressure failure due to lack of onshore compression: For the Shell terminal at the Bacton Gas Terminal[\[41\]](#), it is explicitly stated: gas treatment capacity 900 mmscfd, but **no onshore gas compression**; the system is “balanced” under pressure from the UK National Transmission System. Failure condition: As soon as offshore sources (late-life, water-loaded, lower reservoir pressure) cannot maintain the required entry pressure, they *cannot* market their gas despite the short

distance, except through upstream compression (which in turn increases OPEX/emissions/complexity). [\[42\]](#)

Dew point/water specification failure as a processing gate: At the Bacton complex, dew point control is not optional: Perenco-Bacton relies on a single gas compressor for its dew pointing capability (max. 750 mmscfd). This means: Additional gas does not fail due to the “pipeline to shore,” but rather due to the **S specification machine** (propane refrigeration, dehydration/dewpointing, compressor train). [\[42\]](#)

Flow assurance failure across the MEG supply chain: The documented full-bore rupture of the Bacton-Leman MEG line PL121 (2021) following freespan growth is a textbook case: MEG infrastructure is a critical system service (hydrate inhibition); if this chain breaks, gas flow immediately becomes risky or impossible—even with a functioning gas export pipeline in the same trench. [\[43\]](#)

NL specification regime (dehydration after compression): The PBL analysis describes for NL Offshore that dehydration is required after compression to meet water content limits specified in transport and sales contracts. Failure condition: If dehydration/water-spec capability is unavailable at the host/landfall or becomes too expensive, gas remains “recoverable” but not contract-compliant. [\[44\]](#)

Infrastructure Failure Conditions

Processing capacity is fragmented and partially a single point of failure: NSTA documents cite a total of 1,650 mmscfd of processing capacity for Bacton across the three facilities (Shell/Perenco/National Grid), while also noting the decommissioning of the old ENI facility. Additionally, Perenco-Bacton “supported by a single gas compressor.” Failure condition: In a network with many satellites, a single compressor issue or turnaround is sufficient to effectively eliminate “capacity.” [\[45\]](#)

Aging and declining reliability as structural throughput constraints: National Gas describes Bacton as having been built in 1968; in the 2030s, the plan is to use interconnectors as the sole gas supply, with “cessation of gas supply from the South North Sea.” Performance documents also note that a 2021 FEED study assumed **2035 as the cessation date** for UKCS incomers and that “brownfield redevelopment” was identified as unviable; the shortlist options focused on “maintain and repair existing assets” through 2035. This is the most severe infrastructure failure mechanism: **time runs out**, and at a certain point, the infrastructure is no longer considered economically viable to extend. [\[46\]](#)

Explicit shut-ins despite existing export routes: The PUK-OSPAR report documents actual shut-ins in active hub networks: Davy platform/subsea infrastructure shut in since 2020; Durango third-party tie-back shut in since 2019; Leman South West subsea well shut in since 2020; Trent has not been in operation since 2021 – each with described export routes toward Bacton. This is exactly “gas is there / system is there / yet it still isn’t flowing,” typically due to integrity, well performance, host prioritization, or cost-risk considerations. [\[47\]](#)

Decommissioning permanently removes connection options: Harbour describes the Viking Area: Production stopped in 2016, decommissioning nearly complete, platforms removed, wells plugged and abandoned. Failure condition: When a host is decommissioned or goes into “cold suspension,” every tie-back option is effectively dead—no matter how close the field is. [\[48\]](#)

NL interface: private offshore → TSO onshore: NLOG describes: Offshore gas is brought ashore in the Netherlands via **privately** owned transmission systems (WGT/NGT/NOGAT) and connects there

to the national transmission network (GTS). Failure condition: Even with geographical proximity, a gate arises due to **private capacity and contract regimes** before the TSO network. [\[49\]](#)

Economic failure conditions

Third-party charges/tariffs break down marginal fields: Hartshead explicitly documents indirect costs from third-party charges for transport/processing via Shell infrastructure for an SNS project; these tariffs are “likely gas price linked.” Failure condition: For small fields, this is the direct NPV killer because the margin becomes “doubly volatile” (price + tariff linkage). [\[50\]](#)

Compression OPEX spiral in NL late-life: PBL describes that gas turbine-driven centrifugal compressors are typical in NL offshore (up to ~70 MWth input) and compression often accounts for 70–85% of platform energy consumption; as production declines, turbines become oversized, operate away from the best efficiency point, and efficiency drops. Failure Condition: As soon as additional tie-ins increase compression demand, but the host is already operating inefficiently or oversized, specific OPEX rises so sharply that marginal flows can no longer be “accommodated.” [\[44\]](#)

Macro price/market risk amplifies stop thresholds: EU data show rising LNG importance: in 2025, LNG accounted for 45% of EU gas imports. At the same time, European price volatility remains elevated (IEA: 2024 +50% vs. 2010–2019). Failure condition: In a system with short remaining lifetimes and aging infrastructure, investments in marginal tie-backs are more likely to be postponed or canceled during periods of high volatility because “downside years” override the payback logic. [\[51\]](#)

Systemic-organizational failure conditions

Third-Party Access as a Delay Machine (UK): The NSTA has a formal regime for disputes regarding third-party access to upstream infrastructure; the guidance describes the form and process by which disputes can be referred to the authority. Failure condition: If TPA negotiations (tariffs, metering/allocation, host utilities, liability) do not lead to a signature quickly, a tie-back with a limited host time window becomes a “never-sanctioned project.” [\[52\]](#)

Exemptions/partial TPA exemptions for interconnectors: Ofgem documents on the BBL interconnector show that capacity shares were temporarily exempt from regulated TPA; at the same time, the initial capacity (15 bcm/year) is specified. Failure condition: Cross-border pipelines physically exist but cannot arbitrarily serve as a “relief path” for offshore gas if access/regulatory frameworks are restricted or capacity is segmented. [\[53\]](#)

M&A/portfolio restructuring as an indirect failure indicator: Eni’s acquisition of Neptune (closing January 31, 2024, portfolio excluding NO/DE) is an example of operators in mature systems consolidating assets to improve economies of scale, bargaining power vis-à-vis infrastructure owners, and portfolio management. This is typically a reaction to structural bottlenecks (OPEX, TPA gates, Decom liabilities), not a sign of “system functionality.” [\[54\]](#)

Temporal Dynamics and Decision Thresholds

Early Phase: Capacity Competition vs. Capacity Slack

In the Norwegian model, the core is already stated in the political framework description: Small discoveries near infrastructure can be integrated quickly – **if capacity is available**. The bottleneck is thus systemic early on (Allocation/Capacity Competition). [\[55\]](#)

Historically, there was more slack in the UK-SNS model; today, fast-track projects are possible if tie-back-capable: OEUK cites 2–5 years to first production as a realistic timeframe for tie-backs. In

practice, however, this increasingly fails due to host pressure, single points of failure, and negotiations. [\[56\]](#)

Mid-Life: Optimization Limits (Debottlenecking) and “Reserved Capacity” Cap

Norway (Saturation Model): Record deliveries of 117.6 bcm with network capacity of ~120 bcm/year mean that additional volumes can often only be offloaded through debottlenecking (e.g., Kollsnes upgrades) and precise network optimization. At this point, “reserved capacity” caps (Nova/Gjøa) appear as a visible allocation barrier. [\[57\]](#)

SNS (Decay Model): Mid-life optimization here often means not “more capacity,” but “just enough uptime.” The OSPAR shut-ins show that even at mid-life, parts of the system can fail permanently, even though main pipelines and terminals continue to exist. [\[58\]](#)

Late-Life: Abandonment threshold due to pressure loss, OPEX spikes, and decommissioning countdown

Norway (integrated robustness, but high coupling risks): Late-life does not necessarily mean “system dies,” but rather “system becomes vulnerable.” The Sleipner riser crack demonstrates that integrity-related failures in a highly coupled network can trigger major economic shocks (price reactions, onshore cascades) . In late life, the threshold for new satellites therefore rises: they must not only have a positive NPV but also be **uptime/operational risk tolerant**. [\[59\]](#)

SNS (structural time decay): If system planning assumes that UKCS in-comers will phase out starting around 2035, and brownfield redevelopment is considered unviable, a hard “end-of-system” horizon emerges. Projects that do not reach FID/integration by then will effectively be stranded. [\[60\]](#)

Decision thresholds: Delay vs. Abandonment

Delay triggers (typical):

- Capacity *expected* to be available, but not within the correct time window (turnaround/shutdown collision). [\[61\]](#)
- JV/TPA negotiations not concluded, but resolvable in principle (NSTA dispute regime as an indication that time is being lost precisely here). [\[52\]](#)
- Host modifications required, but still economically “viable” (classic brownfield gate). [\[62\]](#)

Abandonment triggers (typical):

- Recoverable volumes fall below the robustness threshold (Trolldhaugen EWT result → no PDO participation). [\[33\]](#)
- Decommissioning status reached (Viking Area: platforms removed, wells P&A). [\[63\]](#)
- Pressure/specification mismatch cannot be corrected without significant OPEX/CAPEX increases (Bacton without onshore compression; NL compression OPEX spiral). [\[64\]](#)

System failure zones and conditions for alternative off-take paths

System failure zones: where bottlenecks are concentrated

Norway (capacity saturation at hubs): Failure is not concentrated “far away,” but rather at the major nodes and their specification/allocation envelopes: Sleipner complex (CO₂ removal dependency and many tie-ins), Troll/Kollsnes corridor (compression + onshore processing), as well as area hubs like Gjøa, where reserved capacity caps production. [\[65\]](#)

UK–NL SNS (Aging and Entry Pressure Zones): Failures are concentrated in catchments where many old satellites are connected to a few terminals/hubs: Bacton Catchment (Shell/Perenco/National Grid; lack of onshore compression; single compressor; MEG chain), Leman/Indefatigable/LAPS networks and their integrity risks (PL121 rupture), plus NL landfall interfaces from private offshore → GTS onshore, where contract/capacity regimes before the TSO slow down monetization. [\[66\]](#)

Conditions under which alternative off-take paths become “necessary” (without specifying a solution)

This is not about technology options, but about the point at which conventional tie-backs **structurally** fail:

A – Norwegian Continental Shelf: Alternative off-take path logic becomes imperative when at least one of the following conditions is met:

- **System capacity is permanently close to full utilization**, meaning new satellites could only be made available through debottlenecking, which is not being implemented in a timely manner or under risk/cost criteria. [\[67\]](#)
- **Specification services (e.g., CO₂ removal/blending envelope)** are the bottleneck and cannot be expanded within the existing hub window. [\[68\]](#)
- **Allocation caps (reserved capacity) prevent additional volumes from being nominated**, even if physical space were available. [\[36\]](#)
- **Interconnection risk/uptime** at critical connection points increases so significantly (based on incident experience) that marginal projects no longer meet the required availability assumption. [\[30\]](#)

B – Southern North Sea UK–NL: Alternative offtake path logic becomes mandatory if at least one of the following conditions is met:

- **Entry pressure cannot be maintained and there is no onshore compression at the terminal**, which “locks out” low-pressure gas despite the infrastructure. [\[42\]](#)
- **Processing/dewpointing depends on single-point components** (single compressor), and the resulting uptime/capacity volatility makes additional tie-ins no longer plannable. [\[69\]](#)
- **The MEG/flow assurance service chain is fragile** (PL121 rupture/free span), so system operation is only possible with a high risk of outage. [\[70\]](#)
- **The decommissioning countdown reduces the payback window to an internal minimum** (2035 cessation assumptions; brownfield redevelopment unviable; hosts are being decommissioned). In this state, even technically viable projects are “permanently delayed” until abandonment. [\[71\]](#)
- **Contract/access regimes generate negotiation durations and tariff risks** that destroy NPV robustness for small fields (TPA dispute regime; price-linked third-party tariffs). [\[72\]](#)

Conceptual economic consequences (without figures)

The monetary impact of these failure conditions is clear through three mechanisms:

1. **Lost production / stranded gas:** Gas remains in the ground or behind the host gate because capacity/specifications/pressure/contract requirements are not met. This is directly observable at Nova (capacity constraints due to reserved capacity) and the SNS shut-ins despite export routes. [\[73\]](#)

2. **Delayed monetization:** Even if future development were possible, delay massively reduces the time value; with high price volatility, the expected value is additionally “eroded.” [74]

3. **NPV compression due to uptime risk and OPEX spiral:** Declining availability (single points, integrity, turnarounds) and rising specific compression/processing costs push marginal projects below internal robustness criteria (Trolldhaugen example as a documented stop). [75]

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